Austin Energy
Rate Analysis and Recommendations Report

August 29, 2011

Rate Analysis and Recommendations Report

Austin Energy

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Preface: Letter from SAIC, Energy, Environment & and Infrastructure, LLC

August 22, 2011

Mr. Larry Weis
General Manager
Austin Energy
Town Lake Center
721 Barton Springs Road
Austin, TX 78704

Subject: **Austin Energy Cost of Service and Rate Design Analysis**

Dear Mr. Weis:

In August 2010, Austin Energy retained SAIC (formerly R. W. Beck) to perform cost of service and rate design analyses in conjunction with utility staff and to support staff during the rate review process. The analyses as described in the Rate Analyses and Recommendations Report for Test Year 2009 dated August 31, 2011 (Final Report) accurately reflect the analyses and supporting processes undertaken over the last year.

The study presents results developed through a three-step process:

1. Revenue Requirement, which determines the amount of revenue to be generated from rates.
2. Cost of Service, which determines the cost responsibility of each customer class in meeting the Revenue Requirement.
3. Rate Design, which determines the specific rates and charges to be used to recover the cost of service from customers within each class.

Each step of the analyses was performed in accordance with the City of Austin's Financial Policies applicable to Austin Energy and Austin Energy's Strategic Direction. Further, revenue requirement, cost of service, and rate design methodologies employed in the conduct of the study reflect generally accepted practices in the electric industry applicable to municipally owned electric utilities.

Based on our review and analyses, and predicated on the assumptions therein, we conclude the following:

Revenue Requirements

1) Austin Energy's current rates generate insufficient revenue to cover its costs of operation, maintenance and other financial obligations. As a result, Austin Energy has been drawing down reserves to meet its financial obligations. If uncorrected, AE's reserve fund levels will not meet the requirements set forth in its financial policies as established by the City of Austin.

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1801 California Street, Suite 2800 | Denver, CO 80202 | tel: 303.299.5200 | fax: 303.297.2811 | saic.com/EEandI

2) The Test Year 2009 revenue requirement, which reflects fiscal year 2009 audited financial performance adjusted for known and measurable changes, reasonably reflects the utility's operating costs at the time rates are expected to take effect in January 2012.

3) The Test Year 2009 revenue requirement indicates that overall system rate revenue should be increased by 13.1%. At this level, revenues will be sufficient to meet operation and maintenance expenses, debt service and debt service coverage level specified in Austin Energy's financial policies, planned capital improvement expenditures, city transfers and franchise fee obligations, and required contributions to reserves.

Cost of Service

4) The cost of service analysis provides a reasonable representation of the costs incurred by Austin Energy in serving its various customers in newly established customer classes that will better reflect Austin Energy's strategic direction. Allocation methods employed generally reflect the fixed and variable nature of Austin Energy's underlying cost structure and the associated cost causation attributable to specific customer classes.

5) The allocation of production demand related costs using the Average and Excess Demand Method (AED) is a reasonable approach and fairly assign costs to Austin Energy's customer classes. Variations of the AED production cost allocation methodology have been used by other utilities across the industry and are recognized by the Public Utility Commission of Texas.

Rate Design

6) Rate design, as proposed in the Final Report, is sufficient to meet the Test Year 2009 revenue requirement. However, special contract customer rates are fixed until June 2015. As a result, the proposed overall system rate increase of 13.1% actually yields 11.1% during the first 3-½ years of rate implementation. Thus, revenues are projected to be insufficient to meet the TY 2009 revenue requirement and prevent Austin Energy from replenishing reserves to targeted levels until special contract customer rates are adjusted to proposed levels.

7) The proposed rate design in the Final Report was developed in consideration of several rate design objectives that are in alignment with Austin Energy's strategic direction. These objectives include compliance with the laws and regulations governing Austin Energy, maintaining the financial strength of the utility, reflecting cost of service results, transparency, understandability, affordability and fairness in rate design, supporting conservation and efficiency efforts, and providing consideration for low income customers. The proposed rates and charges represent a reasonable balancing of these many, sometimes competing, rate design objectives.

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8) The proposed rate design in the Final Report includes an Energy Adjustment which replaces the Fuel Adjustment Clause. The Energy Adjustment is intended to minimize fluctuations in retail rate revenues related to net ERCOT wholesale market power costs. To accomplish this result, the Energy Adjustment will work in coordination with a Rate Stabilization Reserve as described in the Final Report. The Rate Stabilization Reserve provides important funds required to help levelize short term fluctuation in net wholesale market costs. Therefore, the implementation of the Energy Adjustment and funding of the Rate Stabilization Reserve should be considered conjunctively (i.e., one will not work properly without the other).

9) The proposed residential rate is designed to improve fixed cost recovery and incentivize customers to conserve. As a result, customers will experience variability in annual bill impacts depending upon usage levels. For low usage customers, these variations are cost based. For high users, these variations represent desired pricing signals to incentivize a reduction in energy usage.

10) The proposed Secondary Voltage rates introduce a demand charge to customers with maximum monthly demands of 20 kW or less and all Worship, Water and Wastewater and Other City customers that currently do not have a demand charges. The demand charge renders a strong price signal to commercial customers to reduce demands on the utility system and improve the efficiency of energy usage. As a result, these customers will experience wide variability in annual bill impacts depending upon their monthly load factors and their ability to reduce demand. These rate structures incentivize commercial customers to improve their monthly load factors. Customers with higher monthly load factors will receive a lower average rate than customers with lower monthly load factors. Due to the potential for significant bill impacts, a three year rate phase-in plan was developed for these customers.

11) Proposed rate designs for other secondary, primary and transmission voltage commercial and industrial customers are similar to existing rate structures, therefore, bill impacts associated with proposed rates should not materially vary from the overall class rate changes.

Given these conclusions, we recommend that the revenue requirement, cost of service analyses, and proposed rates as presented in the Final Report be presented by Austin Energy to the Electric Utility Commission and the Austin City Council.

Sincerely,

SAIC Energy, Environment & Infrastructure, LLC

Joseph A. Mancinelli
Vice President

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Executive Summary to Austin Energy Rate Analysis and Recommendations Report

Much has changed in the 17 years since Austin Energy's last comprehensive rate review. The Austin Metropolitan Statistical Area population has grown from a little over one million in 1995 to about 1.8 million in 2010; Austin Energy added about 115,000 customers, a 38 percent increase. Texas electric markets are now deregulated. Austin's urban core is bursting with new vitality and now hosts both high-density housing and a wide range of commercial enterprises. Residential communities, both single- and multi-family, have spread out across Austin Energy's service territory.

Always a home for University of Texas students, staff, and faculty, Austin has now also become a major event and tourism center, drawing large crowds of visitors for music, sports, and business events. Customers are using a wide range of new, electrically powered devices and equipment unanticipated 20 years ago. Austin hosts a thriving high-tech industrial sector that provides thousands of jobs and needs superior electric power quality and reliability. The greater Austin community looks, works, and plays very differently than it did less than two decades ago. Austin Energy, which provides energy to this community, has changed as well.

Since 1994, Austin Energy has made significant financial investments in infrastructure to ensure adequate power supply and reliability. Program offerings have been expanded in response to customer demand and strategic goals. Austin Energy's business functions are guided by a strategic plan approved by the Austin City Council in December 2003. The strategic plan emphasizes management of overall risk, sustainability of financial health, high system reliability and resource availability, innovative energy resources, cost-effective adoption of new technologies, and excellent cutomer service.

Over the last 17 years, Austin Energy has added new functions and programs, technology systems, homeland security measures, and additional power supply, and has improved its energy service delivery system. The utility earns high scores for reliability and consistently receives national recognition as a leader in energy efficiency and for its GreenChoice® program. Austin Energy is a strong partner in the region's economic growth and in community development. As a utility wholly owned by the City of Austin, the utility has returned hundreds of millions of dollars to the community in General Fund support and direct economic assistance.

Austin Energy's investments in clean energy and superior operational performance have also spurred the creation of local jobs in related fields like solar system installation, home and business energy efficiency, green building design and construction, and advanced electric system engineering. Now, Austin Energy needs to adjust its rates and rate structure in order to continue delivering clean, affordable, reliable energy and excellent customer service.

Austin Energy's 1994 vintage rate structure no longer serves the community or the utility, and does not reflect the reality of Austin Energy's business situation. Electric utility rates are designed to achieve financial goals and provide an essential service in a manner that serves the public interest. When rates no longer meet strategic public policy and business objectives, review and redesign are necessary. Austin Energy is not alone in facing the need for change. Over the past two decades, there have been fundamental changes in the way other services are provided and priced, such as cellular phone and cable television. Today, the greater Austin community needs Austin Energy to offer a modernized rate structure that promotes efficient use of energy, new energy resources, and adoption of new cost-effective energy technologies, all the while ensuring financial health and achievement of the utility's mission to deliver clean, affordable, reliable energy and excellent customer service.

Benefits of Public Power

Austin's first utility company, the Austin Water, Light, and Power Co., was a private company formed in 1887. The City of Austin determined that local control of electric service and reliability were so important to the community that, in 1902, the City purchased the company and has owned its generation and distribution system ever since. Austin Energy, the City of Austin's municipal electric utility, has provided electric service to the local community for over 100 years.

Austin Energy's service area currently encompasses 206.41 square miles within the City of Austin itself and 230.65 square miles of surrounding Travis and Williamson Counties.

Austin Energy is a public power electric utility directly accountable to the communities it serves.

Public power is a collection of more than 2,000 community-owned electric utilities, serving over 45 million people or about 14 percent of the nation's electricity consumers. The Public Power model delivers a number of distinct benefits to customers and communities. These benefits include:

- Austin Energy's policies and strategic objectives are set locally, directly reflecting community values and priorities and taking into account both near and long-term needs and concerns.
- Austin Energy's major investments are decided locally with high levels of public involvement opportunity.
- Austin Energy's staff are quick to respond to emergency problems or customer needs because they are citizens of our local and surrounding communities.
- Austin Energy's rates generate contributions to the local General Fund that benefit all members of the community—and are not distributed to distant stockholders.
- Austin Energy supports the local economy with direct and indirect contributions to economic development, community activities, and education.

Need for Rate Review

Austin Energy last reset base electric rates (non-fuel) in 1994. While those rates have served the public interest for longer than expected, comprehensive review and redesign are necessary. Austin Energy has successfully met the challenges of the last two decades with revenue from customer growth as well as cost-cutting, adjustments, deferrals, and new initiatives. The cumulative effects of nearly two decades of changes in the utility industry, the state of the economy, the shape of local business and industry, and the way customers use electricity must be effectively addressed for Austin Energy to continue to successfully serve the community cost effectively.

A sound financial condition and rates sufficient to cover expenses and investments are fundamental to maintaining and enhancing electric infrastructure, obtaining competitive borrowing rates, effective market participation, and the ability to attract and retain a highly skilled workforce.

Key drivers for rate review and change are economic, financial, market-related, and regulatory. These include:

- Austin Energy's current rate structure is misaligned with its cost structure, thus, Austin Energy under-recovers its fixed costs. Austin Energy is geographically limited, infrastructure-driven, subject to large sales variation due to economic conditions, and focused on reducing customer bills through a combination of affordable rates and cost-effective energy efficiency investment.
- Austin Energy must pay its fair share of statewide investments in transmission infrastructure and market operation systems (the "Nodal Market"). While these investments are expected to provide significant savings, they represent a new cost for Austin Energy.
- Austin Energy's revenue growth has eroded in recent years while the price of nearly everything has risen. From health care costs to commodity prices for steel, cable, and concrete, Austin Energy's base rates set in 1994 no longer reflect economic conditions.
- Austin Energy today operates in a very different financial market than 17 years ago. The financial markets crisis has adversely affected interest rates on deposits and other costs related to financial transactions, such as letter of credit fees.
- Austin Energy's customers have been significantly impacted by recent economic conditions, which in turn have directly affected Austin Energy earnings. Many large industrial and small commercial customers have cancelled or deferred expansions. The new construction markets for homes and small businesses have slowed.

Austin Energy must review and revise its rates to address the financial and revenue impacts of these changes, but also must devise and implement the measures necessary to mitigate adverse impacts from the continuation of the major trends.

In this review, the utility continues to be guided by a strategic set of objectives summarized in the following section.

Rate Review Objectives

Austin Energy is guided by a set of policy objectives derived from Austin Energy's approved strategic plan:

- ***Ensure long-term financial strength by setting rates that meet Austin Energy's revenue requirement and achieve sustained revenue stability;***
- ***Improve fixed cost recovery to maintain sufficient revenues into the future;***
- ***Align rates with Austin Energy'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***
- ***Update rates and rate structures to distribute costs fairly among customer classes and encourage efficient energy use.***

Public Involvement Process

Austin Energy formally launched the rate review process in January 2011. In addition to input sought and received at numerous Austin City Council and Electric Utility Commission meetings, the utility convened a Public Involvement Committee (PIC) to act as a sounding board for the many issues involved in developing rate recommendations and options. The PIC met monthly from January through June of 2011, and was composed of 14 members of the community representing all Austin Energy customer classes and major stakeholder groups.

Austin Energy also retained an Independent Residential Rate Advisor to provide input and feedback specifically from the perspective of residential customers. The Independent Residential Rate Advisor will produce a public report.

Materials developed for the PIC process and in response to the many inquiries received from customers and the public have been published at Austin Energy's dedicated rate review website, www.rates.austinenergy.com.

Throughout the process, Austin Energy has delivered public, televised briefings about the rate review process to the Electric Utility Commission and Austin City Council. Austin Energy will continue these activities throughout the coming months.

Revenue Requirement

Austin Energy began the internal process of reviewing rates by determining how much revenue is required from customers in a single year to continue to provide electric service. The total revenue requirement process collects data on the costs for the functions of power production, transmission, distribution, and customer service.

Revenue Requirement is the total amount of money that must be collected from customers through rates in order to pay all the costs of running the utility during a representative "Test Year."

Comparing the total revenue requirement to the amount of money actually collected in base rates is the next step in the process. Table ES-1 presents the summarized results of the revenue requirements study.

Table ES.1
Total Revenue and Revenue Need

Measure	Test Year 2009
Total Revenue Requirement ($)	1,136,020,803
Test Year Rate Revenue Under Existing Rates ($)	1,004,133,897
Needed Increase in Revenues ($)	131,886,906
Needed Increase in Revenues (%)	13.1
Needed Increase in Revenues From Contract Customers ($)	20,751,131
Requested Increase in Revenues ($)	111,135,775
Requested Percent Increase in Revenues (%)	11.1

Austin Energy's total revenue requirement is $1.1 billion. The utility requires an additional $131.9 million in annual revenue, representing a 13.1 percent average increase in revenues. Approximately $20 million of the amount Austin Energy needs to collect from its customers to meet the total revenue requirement can be directly traced to growth in the cost of serving large industrial customers currently on the long-term contract rates. These contracts expire in May 2015, so the associated revenue requirement has been excluded. Other residential and commercial customers will not be asked to pay the long-term customer portion of the increased revenue requirement. The adjusted revenue requirement is $111.1 million or a 11.1 percent increase.

Cost of Service

The next major component of any rate review is a cost of service study. This study groups customers into rate classes based on similar characteristics, and then assigns total revenue requirements to these customer groups based on the costs of providing them with service. Generally, customer classes differ according to how much energy they use and how they use it—known as "level of service."

The Cost of Service Study calculates the fair share of total revenue requirement that each customer class should pay.

The cost of providing electric service to Austin Energy customers has changed. While rates were originally set to fairly charge for a customer's level of service, today those rates do not properly cover costs. Rate review and redesign is now necessary to re-align rates to more closely reflect the cost to serve customers. Table ES-2 summarizes the results of the cost of service study.

Table ES.2
Cost of Service Results by Customer Class

Customer Class	Revenue Deficiency ($ millions)	Increase Needed to Meet Cost of Service (%)
Residential	107.0	28.7
Secondary Voltage <10 kW	10.0	27.5
Secondary Voltage 10 - <50 kW	3.3	3.6
Secondary Voltage ≥50 kW	2.2	0.6
Primary Voltage <3 MW	(1.2)	(3.9)
Primary Voltage 3 - <20 MW	4.6	9.8
Primary Voltage ≥20 MW	5.1	8.8
Transmission Voltage	(1.6)	(10.3)
AE-Owned Private Outdoor Lighting	1.9	97.4
Non-Metered Lighting	0.0	34.4
Metered Lighting	0.5	126.8
Total	**131.9**	**13.1**

Rate Design

Austin Energy used the revenue requirement and cost of service study analysis to design new rates for each customer class. The electric bill that customers pay each month is actually a combination of a wide range of charges associated with all the activities needed to provide service.

The Rate Design process seeks to fairly assign total cost of service to rate elements so that customers can understand and manage their electric bills more effectively.

For residential customers, Austin Energy proposes the following cost components:

Customer Charge for billing, meters, customer service, and other customer service related costs.

Electric Delivery Charge for the electric system infrastructure and equipment that delivers electricity to homes and businesses.

Energy Charge for power production costs including fuel costs.

Energy Adjustment Charge to account for future fluctuations in fuel and energy market costs.

Regulatory Charge for statewide transmission costs and regulatory fees imposed outside of the utility's control.

Community Benefit Charge for costs associated with services that provide benefit to the community, including the Customer Assistance Program, street lighting, and energy efficiency programs.

Commercial customers see additional rate components broken out on their bills, including a demand charge and power factor adjustment. These costs are included in the energy charge for residential customers..

Residential Rate Options

Austin Energy prepared several rate design options for residential customers. While these different options are all designed to recover the full revenue requirement associated with residential electric service in the Austin community, they vary in some important ways.

All Austin Energy residential rate options seek to recover more of the cost of service from fixed charges than was the case in the 1994 rates. As Table ES-3 shows, none of the options seek to implement rates strictly according to the cost of service analysis. The utility's goal is to implement rate redesign as close to cost of service as possible. Strict implementation would be impractical.

Austin Energy used the cost of service study, policy, and principles of sound rate making as the basis for rate design.

All Austin Energy residential rate design options continue the long-standing structure of providing a lower rate for the first tier of usage to encourage conservation and support efficient energy use. Some of the options include additional rate levels or tiers, with the rate increasing progressively as customers increase total energy use. This design feature encourages even more efficient use of energy by providing customers with a real savings incentive. Table ES-4 provides additional comparative information about the residential rate design options.

Table ES.3
Residential Rate Options and Estimated Prices

Residential Rate Options (summer season only)	Existing Rate	Cost of Service	Option Supported by Rate Analysis & Recommendation Report	Staff Options		
			Option A	Option B	Option C	Option D
Customer Charge ($/month)	$6.00	$21.69	$15.00	$10.00	$10.00	$30.00
Electric Delivery ($/month)	Inc. Below	$14.13	$10.00	$10.00	$6.24	N/A
Energy Charge (¢/kWh) – *Summer Period (June-Sept)*						
< 500 kWh *(32% of bills)*	6.948 ¢	7.504 ¢	5.514 ¢	5.514 ¢	6.948 ¢	0-300 (cust. charge)
501 – 1000 kWh *(33% of bills)*	11.218 ¢	7.504 ¢	9.514 ¢	9.514 ¢	11.218 ¢	300-1000 @ 10.000 ¢
1001 - 1500 kWh *(18% of bills)*	11.218 ¢	7.504 ¢	12.014 ¢	13.503 ¢	11.218 ¢	12.188 ¢
1501 – 2500 kWh *(13% of bills)*	11.218 ¢	7.504 ¢	13.514 ¢	16.003 ¢	11.218 ¢	13.712 ¢
> 2500 kWh *(5% of bills)*	11.218 ¢	7.504 ¢	14.514 ¢	17.503 ¢	11.218 ¢	14.728 ¢
Energy Adjustment (¢/kWh)	Inc. Above	-	-	-	-	-
Community Benefit (¢/kWh)		See below	See below	See below	See below	See below
Customer Assistance Program	Inc. Above	0.065 ¢	0.065 ¢	0.065 ¢	0.065 ¢	0.065 ¢
Service Area Street Lighting	Inc. Above	0.114 ¢	0.114 ¢	0.114 ¢	0.114 ¢	0.114 ¢
Energy Efficiency Charge	Inc. Above	0.301 ¢	0.301 ¢	0.301 ¢	0.301 ¢	0.301 ¢
Regulatory Charge (¢/kWh)	0.082 ¢	0.729 ¢	0.729 ¢	0.729 ¢	0.729 ¢	0.729 ¢
Average Monthly Bill at Usage Shown						
300 kWh Avg Annual Electric Bill	$26.84	$60.89	$42.96	$37.96	$40.71	$33.63
1000 kWh Avg Annual Electric Bill	$92.33	$119.39	$102.21	$97.21	$113.16	$102.76
2500 kWh Avg Annual Electric Bill	$247.10	$244.74	$289.53	$312.55	$281.57	$292.54
Monthly Dollar Difference from Current Rates						
300 kWh Avg Annual Electric Bill		$34.05	$16.12	$11.12	$13.87	$6.78
1000 kWh Avg Annual Electric Bill		$27.06	$9.88	$4.88	$20.83	$10.43
2500 kWh Avg Annual Electric Bill		($2.36)	$42.43	$65.45	$34.47	$45.44
Percent Change from Current Rates						
300 kWh Avg Annual Electric Bill		127%	60%	41%	52%	25%
1000 kWh Avg Annual Electric Bill		29%	11%	5%	23%	11%
2500 kWh Avg Annual Electric Bill		-1%	17%	27%	14%	18%

Table ES.4
Evaluation Matrix for Residential Rate Options

		Option Supported by Rate Analysis & Recommendation Report	Staff Options		
Rate Review Objectives and Policy Metrics	**Cost of Service**	**Option A Achieve Rate Review Objectives**	**Option B Shift Greater Fixed Costs to Energy Charge**	**Option C Current Energy Rates with New Fixed Charges**	**Option D 300 kWh Energy in Basic Monthly Charge & 4 Tiers**
Achieves Revenue Stability	Collecting all fixed costs in customer charge reduces revenue uncertainty due to economic volatility. Rate stabilization reserve established.	Improves fixed cost recovery and reduces revenue uncertainty. Rate stabilization reserve established.	Improves fixed cost recovery and reduces revenue uncertainty. Rate stabilization reserve established.	Improves fixed cost recovery and reduces revenue uncertainty. Rate stabilization reserve established.	Improves fixed cost recovery and reduces revenue uncertainty. Rate stabilization reserve established.
Ensures Long-Term Financial Strength	Meets revenue requirements.	Meets revenue requirements.	Meets revenue requirements.	Meets revenue requirements.	Meets revenue requirements.
Improves Fixed Cost Recovery	100%	70%	56%	45%	84%
Promotes Energy Efficiency & Distributed Solar	Weak incentive.	Strong incentive.	Strong incentive.	Weak incentive.	Strong incentive.
Minimize inter-class subsidies vs. cost of service study	Achieves cost of service and eliminates all inter-class subsidies.	All rate classes within 5% of cost of service goal.	All rate classes within 5% of cost of service goal.	All rate classes within 5% of cost of service goal.	All rate classes within 5% of cost of service goal.
Minimize intra-class subsidies vs. cost of service study	No subsidy. All usage tiers at cost of service.	Intra-class subsidy at mid-level.	Highest intra-class subsidy.	Lowest intra-class subsidy.	Intra-class subsidy at mid-level.
Provides Rates Simplicity	Similar to 1994 structure.	Introduces multiple tiers.	Introduces multiple tiers.	Similar to 1994 structure.	Introduces multiple tiers.
Customer Assistance Program funding.	Improves.	Improves.	Improves.	Improves.	Improves.

Commercial and Industrial Rate Recommendations

Austin Energy redesigned rates for commercial and industrial electric service. The demand charge, based on a customer's monthly peak demand, reflects the way these costs are incurred in serving commercial and industrial customers. A demand charge also provides an effective pricing signal for commercial customers to conserve energy and improve efficiency of electricity use.

A number of recommendations are proposed for the structure of commercial and industrial customer rates:

Class Consolidation: Consolidate commercial and industrial customers into seven classes.

Demand Charges: Expand the use of demand charges to all Secondary Voltage customers.

Demand Charge Phase-in: Phase in demand charges over three years for the smallest commercial customers.

Add Customer Charge: Apply a customer charge at or near cost of service for all commercial and industrial customers.

Add Electricity Delivery Charge: Apply an electricity delivery charge on a $/kW basis for all commercial and industrial customers.

Power Factor: Increase power factor adjustment from 85 to 90 percent to all but the smallest commercial customers.

Regulatory Charge for statewide transmission costs and regulatory fees imposed outside of the utility's control.

Community Benefit Charge for costs associated with services that provide benefit to the community, including the Customer Assistance Program, street lighting, and energy efficiency programs.

Table ES-5 summarizes commercial and industrial proposed rates by proposed customer class. Alternative rates will be available for Time-of-Use, GreenChoice, and Net Metering.

Table ES.5
Commercial and Industrial Proposed Rates

Commercial and Industrial Proposed Rates	Secondary Service <10 kW	Secondary Service 10-<50 kW Non-Demand	Secondary Service 10-<50 kW	Secondary Service ≥50 kW Non-Demand	Secondary Service ≥50 kW	Primary Service <3MW	Primary Service 3 - <20 MW	Primary Service ≥20 MW	Transmission
Customer Charge ($/month)	18.00	25.00	25.00	65.00	65.00	250.00	2000.00	2500.00	2500.00
Electric Delivery ($/kW billed)	1.50	2.00	4.00	2.00	4.50	2.50	3.50	3.50	N/A
Demand ($/kW billed)									
Summer	1.00	2.00	6.50	2.00	8.00	10.00	13.00	13.00	13.00
Non-Summer	1.00	2.00	5.50	2.00	7.00	9.00	12.00	12.00	12.00
Energy (¢/kWh)									
Summer	9.097¢	7.505¢	5.868¢	7.855¢	5.142¢	4.127¢	4.004¢	3.945¢	3.466¢
Non-Summer	7.278¢	7.023¢	5.491¢	7.351¢	4.812¢	3.862¢	3.747¢	3.692¢	3.243¢
Community Benefit Charges (¢/kWh)									
Customer Assistance Program	0.065¢	0.065¢	0.065¢	0.065¢	0.065¢	0.065¢	0.065¢	0.065¢	0.065¢
Service Area Street Lighting	0.113¢	0.088¢	0.088¢	0.078¢	0.078¢	0.066¢	0.062¢	0.059¢	0.053¢
Energy Efficiency Charge	0.296¢	0.231¢	0.231¢	0.206¢	0.206¢	0.174¢	0.162¢	0.156¢	0.139¢
Regulatory Charge									
(¢/kWh)	0.711¢								
($/kW billed)		2.44	2.44	2.57	2.57	2.28	2.93	2.92	2.49
Percent Class Rate Change	22%	9%	9%	6%	6%	1%	16%	15%	-5%

Conclusion

Austin Energy's 1994 vintage rate structure no longer serves the community or the utility, and does not reflect the reality of Austin Energy's business situation. Electric utility rates are designed to achieve financial goals and provide an essential service in a manner that serves the public interest. When rates no longer meet strategic public policy and business objectives, review and redesign are necessary. Today, the greater Austin community needs Austin Energy to offer a modernized rate structure that promotes efficient use of energy, new energy resources, and adoption of new cost-effective energy technologies, all the while ensuring financial health and achievement of the utility's mission to deliver clean, affordable, reliable energy and excellent customer service.

Mission:

To deliver clean, affordable, reliable energy and excellent customer service.

AUSTIN ENERGY®

Section 1
BACKGROUND AND INTRODUCTION TO AUSTIN ENERGY'S RATE REVIEW

Austin Energy ("AE") is proposing a redesign of its electric rates so that it can successfully continue to deliver clean, affordable, reliable energy, and excellent customer service. Austin Energy staff, with the assistance of cost of service and ratemaking experts, spent the past year completing research and analysis to determine the necessary changes to AE's rates and rate structure to ensure the continued financial strength of the utility. This study includes an assessment of the utility's revenue needs, an analysis of the cost to serve different customer groups, a review of existing rates, and the consideration of public input. This study produced a series of recommendations on the redesign of AE's rate structures and a proposal for new electric rates, which are presented in this report.

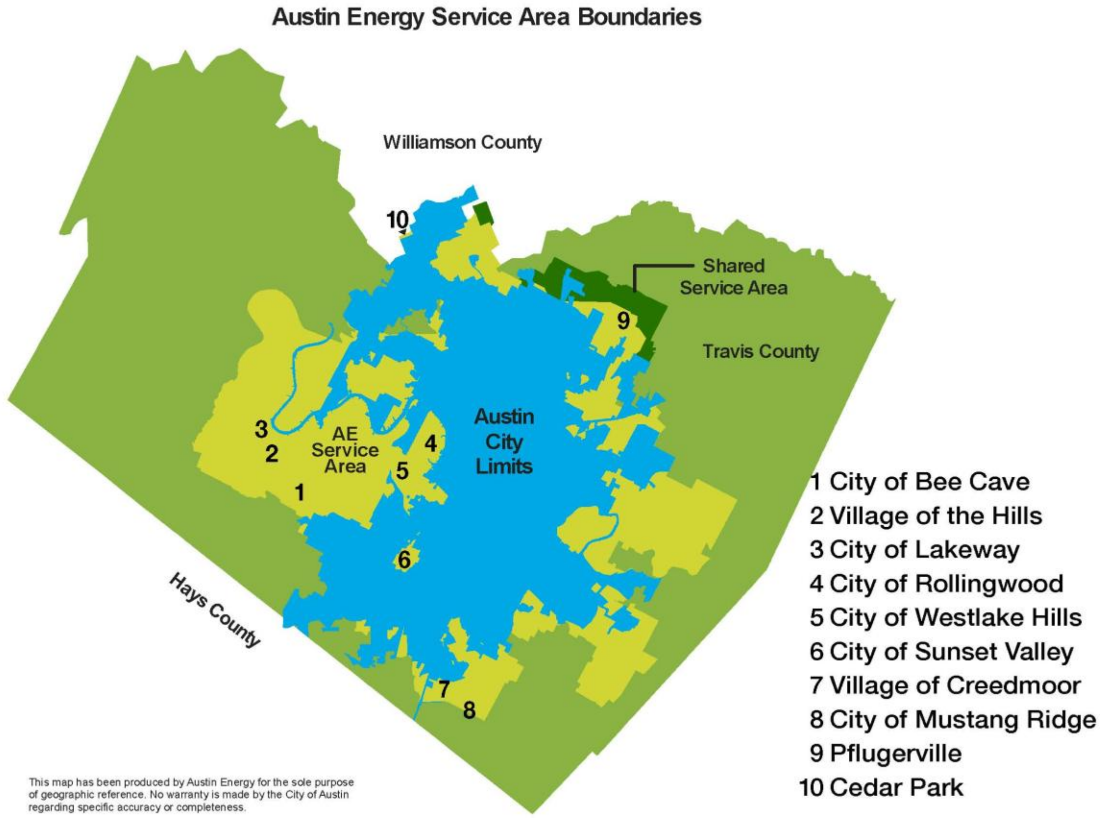
This introductory section of the report provides background on AE, discusses the needs and purpose of this rate review, introduces AE's rate design principles and the rate review process, and provides goals and a set of metrics for evaluating the proposed rates. This section is then followed by several sections of analysis and results on the utility's revenue requirement, the cost to serve different customer classes, and proposed new rates for all classes. The final section of this report presents AE's findings and recommendations. This proposal for new electric rates reflects input from AE staff, the community served by AE, and ratemaking experts with considerable experience in cost of service studies and rate design.

Austin Energy Overview

Austin Energy has provided electric services to Austin and its surrounding communities for over 115 years. Austin Energy is a department of the City of Austin and operates as a separate enterprise fund. The utility provides service to more than 400,000 customers and a population of almost one million, making it the ninth largest municipally owned electric utility in the United States. The Austin City Council ("Council" or "City Council") is responsible for setting AE's retail electric rates. Additionally, the Electric Utility Commission ("EUC") reviews and makes recommendations to the City Council regarding utility rates, policy, spending, and programs.

The AE electric system serves a 437 square mile area. The area includes Austin and other portions of Travis and Williamson counties. Communities served by AE include the municipalities of Bee Cave, Cedar Park, Lakeway, Mustang Ridge, Pflugerville, Rollingwood, Sunset Valley, Village of the Hills, and Westlake Hills. Approximately 14.5 percent of AE's customers reside outside Austin's city limits. Figure 1.1 is a map of AE's service territory.

Figure 1.1
Austin Energy Service Territory



As an electric utility, AE serves as a generator, or producer, of electric power. It performs electric delivery services as a transmission owner and operator and as a distribution company. Transmission refers to the high-voltage electric system that transfers power from generating plants to the distribution system. Distribution refers to the low-voltage electric system that delivers electricity directly to customers. Austin Energy also operates billing and collection systems as well as a customer call center to serve its customers.

Austin Energy has effectively designed and managed an electric system and portfolio of power generation resources to meet the growth and demand for electricity in its service territory and has developed programs that support environmentally responsible initiatives and new customer needs. Austin Energy continues to be recognized as a progressive electric utility that offers many unique, beneficial services to its customers, including some of the most successful renewable energy and energy efficiency programs in the United States.

Austin Energy's Mission

Austin Energy contributes to the quality of life in our community by providing the vital service of electricity, employing over 1,700 members of the community, and supporting community events and city services. Austin Energy's mission statement provides a guide for the utility as it strives to provide the highest quality service to its customers in a manner that reflects the community's values and needs.

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

In support of its mission, AE continues to expand existing programs, implement new programs, add services, and invest in new assets. Austin Energy has taken many actions over the past decade that are tied to the foundational principles of its mission statement. A description of each of these principles is provided below with examples of related initiatives.

- **Affordable Energy** – Austin Energy recognizes that it is important that the price 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 resource diversification, promoting energy efficiency and conservation, and maintaining a Customer Assistance Program that supports low-income and other disadvantaged customers, electricity has remained affordable for AE 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, such as advanced metering infrastructure. Austin Energy ranks at the top of utilities in measures of reliability and continues to be a leader in development of an advanced, or "smart," electric grid. Maintaining a highly reliable system has also minimized the cost of lost productivity associated with power outages, contributing to the affordability objective above.
- **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 the utility's diverse customer types. Austin Energy's Customer Care business unit manages the utility's customer service centers, the City of Austin 311 call center, billing services, a Customer Assistance Program that assists low-income and other disadvantaged customers, and many other customer service functions. Austin Energy also provides support to large commercial customers from a dedicated key accounts group.
- **Clean Energy** – Austin Energy recognizes that it has a responsibility to deliver 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 or install solar photovoltaic ("PV") systems, and continues to add new renewable energy resources to its power generation mix.

Rate Review Need

Austin Energy has not increased its base electric rates (which excludes the fuel charge) since 1994. Over time, the utility's rate structures have become outdated and no longer represent the way the utility incurs costs or the costs to serve different customer types. Costs for commodities and personnel have risen, and the utility has grown by more than 100,000 customers. Austin Energy recognized the need to increase its rates initially in 2006, but a combination of cost control, drawing down utility reserves, and market sales and revenues from abnormally hot weather delayed the action until now. The increased costs to serve customers means that the utility is currently under-collecting the revenues it needs to operate effectively, and rate adjustments are necessary at this time to ensure the continued financial strength of the utility.

Part of the reason that AE has had difficulties meeting its revenue needs recently is that growth in 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 that 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 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. Austin Energy 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 ("SHEC"), 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.

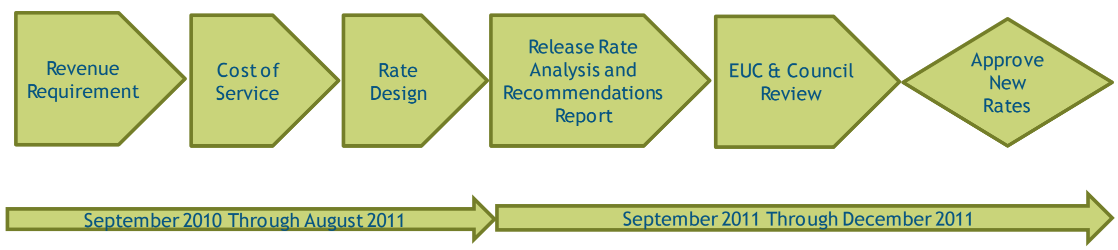
Overview of Rate Review Process

In early 2010, AE began planning for a review of its electric rates and in September 2010 AE began the formal rate study. Over the course of the following year, AE, with the assistance of ratemaking experts, evaluated its current rates, completed a cost of service study, gathered customer input on rates issues, and designed new rates. This report is the product of that year of study and public involvement. The proposed rates will now be reviewed by the utility's oversight bodies, the EUC and the City Council, and the Council will ultimately set new rates.

Analytical Process

Austin Energy's rate review process is illustrated in Figure 1.2. This is followed by a description of the primary steps in the analytical process and an overview of AE's public involvement process as well as communications during the study.

Figure 1.2
Rate Review Process Timeline



Step 1 – Determine Utility Revenue Requirement

The establishment of AE's total utility revenue requirement was the first step in the rate review process. The term "revenue requirement" refers to the utility's total cost to provide reliable service and achieve the utility's strategic objectives. The revenue requirement is the amount of revenue that the utility must recover through rates and other income sources. To help ensure that rates properly recover costs into the future, the revenue requirement represents a forward-looking utility cost structure. A historical FY 2009 was chosen and then adjusted based on "known and measurable" criteria to reflect typical or expected future financial and operating conditions of the utility. This adjustment resulted in a "Test Year" or "TY" that represents the total costs to operate AE during a typical year.

Step 2 – Prepare Cost of Service

A cost of service study was performed to determine how much it costs the utility to provide electric services to different customer types. Prior to the initiation of the cost of service study, similar customers were grouped together into proposed new customer classes. New customer classes were designed to ensure that all customers in each class have similar service requirements and electricity usage characteristics. Each customer class has different rates because the cost to provide electric service to different customer types varies. For example, customers with large loads (i.e., large commercial and industrial) tend to use energy in larger amounts than residential and small commercial customers and more consistently during the day, which impacts the cost to serve these customers. Correspondingly, the cost to deliver electricity to a very large commercial or industrial customer is different from the cost to deliver electricity to a residential home. The industrial customer may receive electricity from a single high-voltage line that extends directly from a substation while a residence receives its electricity from a series of lines that start from a substation and eventually reach the home.

Austin Energy completed an unbundled cost of service study that allocated the costs of specific products and services to each customer class. An unbundled approach to pricing helps ensure full cost recovery, provides greater transparency in pricing, and provides the opportunity to develop more clear price signals for customers to encourage efficient use of resources (e.g., energy efficiency).

Step 3 - Design Rates

After completing the cost of service analysis, AE designed proposed new rates to achieve the utility’s revenue requirement with consideration of the cost of service results, AE’s rate design principles, and public input. Rates can generally be defined as a system of charges developed to collect the needed revenues. Different components of the overall rate structure are designed to recover costs of fixed expenses and variable costs like fuel. Austin Energy is proposing to unbundle rates into components, including customer costs, electric delivery costs, energy costs (including fuel), transmission and regulatory costs, and expenditures that benefit its service area.

Step 4 – Prepare and Submit Rate Analysis and Recommendations Report

Austin Energy prepared its final rate proposal in this Rate Analysis and Recommendations Report. This report is a complete technical compilation of the rate review, including the full cost of service study and other relevant information pertaining to the analyses that support the proposed rates. This report includes all of the utility’s recommendations related to new rate levels and rate structures.

Step 5 – EUC and City Council Review

The utility’s recommendations and findings are being presented to the EUC for review. The EUC will review AE’s rate proposal during a series of public meetings and will make its recommendations to the City Council following its review. Once the EUC review is completed, the proposed rates will be presented to the City Council for further review and approval for implementation. The City Council may request staff presentations and additional public comment on the proposed rates and AE’s rate proposal may be modified before final approval.

Step 6 – Implement New Rates

After completion of the five steps described above and upon final approval of rates by the Council, new rates will be incorporated into the AE billing system and implemented beginning on a date approved by the City Council.

Public Involvement Process and Communications

A critical component of this rate review process is to keep customers informed and provide avenues for AE to receive input from its diverse customer base. Austin Energy has and will continue to update its customers regularly about the rate review process through a dedicated rate review website (www.rates.austinenergy.com) and AE's main website, customer newsletters included with monthly customer utility bills, e-mail and social media services, and the provision of educational materials to customers at public meetings. Austin Energy will also be making presentations on the proposed rates to various community organizations throughout the public review process to keep customers informed and provide an opportunity for feedback.

Public Involvement Committee

In December 2010, AE organized a 14-member committee of citizens representing all segments of AE's customer base that would become educated about utility issues and provide feedback to AE as it developed its recommendation. PIC meetings were held monthly from January 2011 through June 2011 and were open to the public. The purpose of the PIC meetings was to educate PIC members and interested members of the community about AE's rate review, to share perspectives amongst the members, and to provide an opportunity for input to be submitted to AE staff on preliminary study results and policy considerations. Austin Energy provided educational and background information in the form of white papers and presentations on specific rate topics. Table 1.1 details the PIC membership. Table 1.2 details the topics that were presented to the PIC.

Table 1.1
Public Involvement Committee Membership

Customer Type or Interest Group	PIC Representative
Residential – Advisor	Bob Wittmeyer Volatility Managers LLC
Residential – Low-Income	Beth Atherton Caritas of Austin, One Voice
Residential – At-Large	Mark McDonald Bouldin Creek Neighborhood Assoc.
Residential – Distributed Generation	Katherine Sokolic Mueller Neighborhood Association
Commercial – Small Non-Demand	Michael Cation SmarteBuilding
Commercial – Demand	Karen Friese K Friese & Associates
Commercial – Large-Medium Office Buildings	Don Weekly Brandywine Realty
Commercial – Worship facilities	Deacon Ron Walker Catholic Diocese of Austin
Large Industrial	Barry Dreyling Spansion, Inc
Large Commercial Long-Term Contract	Peter Rieck Seton Family of Hospitals
Government (State)	Jorge Ramirez Texas Facilities Commission
School Systems	Wesley Perkins Round Rock ISD
Outside Austin Communities	Steve Jones City Manager - City of Lakeway
Energy Efficiency/Environmental	Colin Meehan Environmental Defense Fund
Residential – Advisor	Bob Wittmeyer Volatility Managers LLC

Table 1.2
PIC Meeting Schedule

Meeting	Meeting Date	Meeting Topic
1	January 13, 2011	Introduction to AE’s Rate Review Process
2	February 8, 2011	Customer Classes and Rates Philosophy
3	March 2, 2011	Revenue Requirement and Cost of Service
4	April 6, 2011	Residential Rate Structures
5	May 4, 2011	Commercial and Industrial Rate Structures
6	June 1, 2011	PIC Feedback and Discussion

Discussions during PIC meetings focused on the topics identified above, and PIC members had the opportunity to submit written questions and comments on the rate topics throughout the process and verbally at the meetings. Following each PIC meeting, a written summary of the meeting was provided to document progress and act as a resource for members of the public who followed the process.

All materials provided to and received from the PIC are available at www.rates.austinenergy.com/rrresources. This includes *White Paper #6 – PIC Summary Report* which summarizes information provided to the PIC and feedback received. The PIC feedback was taken into consideration in the development of AE's rate proposal. A complete compilation of the materials prepared for the PIC, as well as summaries of the discussions and responses to questions submitted by the committee members, has been made available to the EUC and City Council and is available to the public on the rate review website.

Rate Review Project Roles and Responsibilities

During the rate review process AE worked with ratemaking experts (SAIC, formerly R. W. Beck) to perform technical analyses used to support the ultimate recommendations of AE. J. Stowe and Co. also provided independent review of all models and materials during the study. As discussed above, input was sought from the Austin community through multiple channels and this input was taken into consideration as AE prepared its rates proposal. Finally, as noted above, the EUC and the City Council will review proposed rates, with the City Council ultimately approving new rates. The roles and responsibilities of these parties on the project are as follows:

- Austin Energy:
  - Develop analytical process, examine rate structures, and make recommendations.
  - Manage the public involvement process, including organizing the PIC and PIC meetings.
  - Provide technical support and data resources for the project.
  - Assess PIC comments and input from the general public.
  - Oversee and review technical analyses.
  - Prepare recommendations for EUC and City Council review.
- SAIC, formerly R.W. Beck, Consultant Team:
  - Provide technical analyses, including cost of service and rate design analysis, and provide recommendations to AE.
  - Serve as a public involvement resource and assist AE staff as needed.
- J. Stowe and Co. Consultant Team:
  - Provide independent review of the cost of service and rate design analysis, and provide recommendations to AE.

- Public Involvement Committee and Other AE Customers:
  - Consider and discuss technical information on cost of service and rates.
  - Provide input to AE on rates issues.
  - Represent the interests of their customer or interest group and communicate about rate issues with their constituencies.
- Electric Utility Commission:
  - Review AE recommendations and input from the general public.
  - Analyze proposed changes to rates and make recommendations to Council.
- Austin City Council:
  - Review AE and EUC recommendations and input from the general public.
  - Approve any changes to AE rates and set implementation date.

Rate Review Objectives

In planning for and conducting this rate review, AE developed a set of objectives that helped guide staff throughout the study period. These objectives are centered around maintaining the financial well-being of our community-owned utility. A financially sound utility enjoys low cost for borrowing money and faces fewer risks in a changing economy. This keeps costs rates affordable in the long-term for the utility's customers. Specific objectives of this rate review are to:

(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 maintain sufficient revenues into the future;

(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.

These objectives are described in more detail below.

(1) Ensure Long-Term Financial Strength

Austin Energy is an important resource for the community and, accordingly, one of the City's highest priorities is to ensure the utility's financial integrity and competitive standing. Austin Energy is the largest City of Austin department, with revenues of over $1 billion annually and over $3.5 billion in assets. In order to maintain financial strength over the long run, AE must generate sufficient revenue through rates to meet its expenditures. Austin Energy also needs to stabilize reserves to ensure future funding for needed capital expenditures and adequate funds to maintain liquidity in the potentially volatile fuel and power markets.

The rate review process itself is intended to comply with the following AE financial policy:

> *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*.

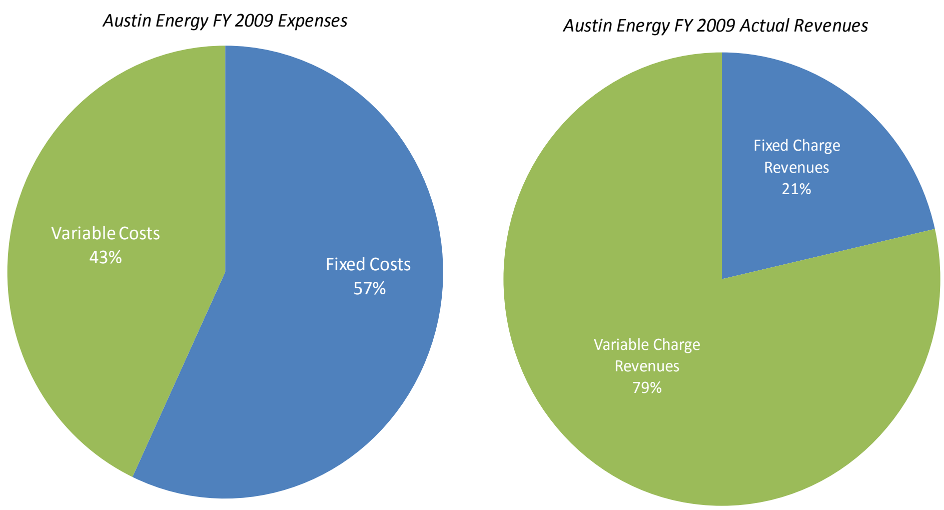
Establishing rates that fully recover the utility's revenue needs is an important factor for determining an electric utility's bond ratings. A utility's bond ratings assess its credit worthiness. As with credit scores for individuals, a bond rating influences the interest rate at which an entity must repay its debt. Therefore, a higher credit rating keeps borrowing costs lower and, in turn, rates lower. Currently, AE has established relatively strong bond ratings, including an AA- rating by Fitch, Inc. Rating agencies have pointed to AE's competitive rates, diverse power supply, consistent efforts to pay down debt, and sound financial record to account for its strong ratings. The evaluation factors considered by bond rating agencies and investors for electric utilities are of mutual importance to AE and its customers, including:

- Cost recovery certainty;
- Comparative rates and competitive position as key measures of a utility's financial health;
- Sufficient future earnings and fixed charge coverage;
- Risk mitigation strategies;
- Sound and predictable management performance and strategies;
- Compliance with debt service coverage and other bond requirements and financial policies;
- Financial flexibility to change with the market and industry including new risks affecting the availability and social acceptability of fuels used; and
- Willingness to adjust rates to maintain sound financial position.

(2) Improve Fixed Cost Recovery

Rising costs and the decline in the growth of electric sales underscore another fundamental issue facing AE: an existing electric rate design that no longer fully recovers the utility's fixed costs. Fixed costs are costs that do not vary with customer usage. The construction cost and ongoing operations and maintenance of power plants, power lines, and substations as well as customer service costs are examples of fixed costs. Larger commercial customers, whose power use peaks above a certain level, pay an additional charge on their electric bill (called a "demand charge") for their share of much of the fixed costs incurred to serve them. Small commercial customers and residential customers do not currently pay a demand charge. Instead, a charge recovering a portion of fixed costs (called the "customer charge") is currently included in their base electric rate. The remaining fixed costs not recovered through the customer charge must be currently recovered through a variable energy charge. In an environment of steady sales growth—as in the late 1990s—AE could be assured of full recovery of its fixed costs through the variable energy charge. However, in an environment of uncertain growth, AE can no longer depend on variable energy sales to recover fixed costs. As illustrated in Figure 1.3, in FY 2009, fixed costs represented 57 percent of AE's budget, but only 21 percent of revenues received were recovered through fixed charges. Therefore, the remainder of these costs were under-recovered through the variable energy charge.

Figure 1.3
Austin Energy's Fixed Cost Challenge: Cost-Structure and Cost Recovery



Improving fixed cost recovery is a major objective for AE. Austin Energy has established a variety of programs that are consistent with its strategic objectives of supporting energy efficiency and conservation as well as customer-owned distributed power generation (e.g., solar PV) and it has established goals of achieving 800 MW of demand reduction through energy efficiency and 200 MW of solar installed (with some portion being customer-owned) by 2020. Since these programs are intended to lower a customer's net energy usage, fixed costs recovered through the variable energy charge may not be fully recovered from customers who participate in these programs or who lower their energy usage through other means. Over time, AE will face an even greater challenge recovering its fixed costs as AE makes progress in achieving these strategic goals.[1]

[1] The fixed cost recovery problem is unique to the electric utility industry. Like many industries, an electric utility must install fixed infrastructure to provide core services. But at the same time, no other industry actively *discourages* customers from consuming its product—through energy efficiency,

To complement and align AE's rates with its strategic goals, the proposed rate design has been developed to improve fixed cost recovery. The strategy to address the fixed cost recovery problems is: 1) to increase or establish fixed monthly customer charges for all customers at or near the fixed amount of those costs to ensure recovery of the fixed customer service costs, and 2) to implement a fixed monthly electric delivery charge for all customers to ensure recovery of the fixed electric system costs that all customers benefit from by being connected to the electric grid. It should be noted that while some of these charges are new for some customers, these costs would otherwise be recovered in existing charges. For example, the addition of an electric delivery charge means a proportionate reduction in the distribution costs otherwise embedded in the energy charge.

(3) Align Rate Design with Strategic Plan

In alignment AE's mission to deliver clean, affordable, reliable energy, and excellent customer service, AE adopted its Strategic Plan in 2003 (with updates as recent as 2011) which established a set of strategic objectives to help AE prepare for the future by reducing financial risk, providing excellent customer service, and acknowledging environmental issues and the importance of energy efficiency and renewable energy programs. In 2010, the City Council adopted AE's *Resource, Generation, and Climate Protection Plan to 2020* ("Resource Plan") which serves as a resource planning guide to bring together demand and energy management strategies over the planning horizon. The Resource Plan establishes clean energy goals, recommits to providing affordable electricity to customers, and continues to stress the electricity reliability and improved customer service targets set forth in AE's Strategic Plan. Additionally, in February 2011 Council approved an affordability goal to accompany the Resource Plan. The affordability goal requires that AE operate so as to limit all-in rate (base, fuel, riders, etc.) increases for residential, commercial, and industrial customers to 2 percent or less per year. In addition, the goal is to maintain AE's rates in the lower 50 percent of Texas rates overall. The affordability goal will be effective upon implementation of AE's new rates following this rate review.

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

- Risk Management:
  - Maintain financial integrity; and
  - Reduce carbon dioxide by 20 percent below 2005 level by 2020.
- Excellent Customer Service:
  - Improve customer and employee satisfaction;
  - Provide exceptional system reliability; and
  - Create and sustain economic development.

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conservation, and distributed generation like solar PV. The more successful the utility is at discouraging energy use, the more exaggerated the fixed cost recovery problem.

- Energy Resources:
  - 800 MW of energy efficiency by 2020;
  - 35 percent of energy from renewable resources by 2020; and
  - 200 MW of installed solar generation capacity by 2020.

(4) Update Rate Structures and Establish Fair Rates

Since the last rate review in 1994, the utility's rate structures have become outdated and no longer represent the way the utility incurs costs or the costs to serve different customer types nor do they recognize changes in the broader electric utility industry have made AE's current rate structures outdated. New environmental concerns, increased regulation, and new technologies are requiring electric utilities to develop and implement non-traditional approaches to rate design and the provision of electric services to ensure sustainability into the future and meet new customer needs.

Addressing the fixed cost recovery problem is one way in which AE is updating its rate structures to establish fair and equitable rates. Another way in which AE is trying to accomplish this objective is by completing an unbundled cost of service study that allocated the costs of specific products and services to each customer class. An unbundled approach to pricing helps ensure full cost recovery, provides greater transparency in pricing, and provides the opportunity to develop more clear price signals for customers to encourage efficient use of resources (e.g., energy efficiency). Unbundling is also intended to accommodate new products and services and support the utility's energy efficiency and customer-owned renewable generation goals.

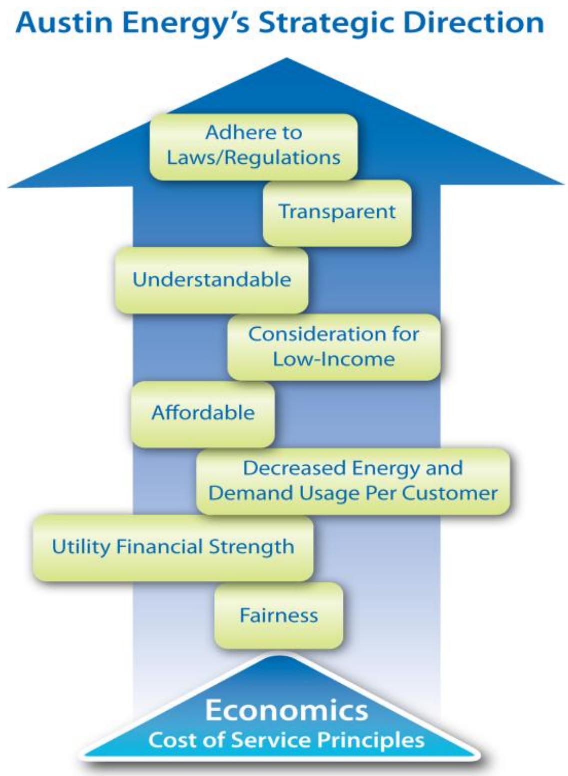
The cost of service analysis performed by AE for this study determined how much it costs the utility to provide electric services to different customer types. Austin Energy's proposed rates are designed to better align customer rates and the rate structures with the cost to serve customers while meeting AE's strategic objectives. Aligning rates to the extent possible with cost of service ensures that customers pay their fair share for receiving electric services while minimizing inter-class subsidization. The proposed new rate structure is intended to be both financially sustainable and provide the flexibility to meet current and future needs of customers.

Austin Energy's Rate Design Principles

After determining the primary objectives of the rate review, AE developed a set of rate design principles to serve as a guide during the ratemaking process. These rate design principles are discussed in more detail in Section 5 of this report. In designing rates, public power utilities like AE consider many factors including the results of a cost of service study and the economic health and priorities of the community. Rates may deviate from the cost of service results within each class, while remaining close to cost of service at the class level to meet social and policy objectives of the utility and the community.

Austin Energy's adopted rate design principles are illustrated in Figure 1.4 and are listed below. All of AE's rate design principles are grounded in industry ratemaking best practices and are representative of local community values.

Figure 1.4
Austin Energy's Rate Design Principles



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 among customer classes.
4. Rates should ensure the long-term 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.

Rate Review Policy Guidelines

Austin Energy developed a series of policy goals and metrics as identified in Table 1.3 to serve as a guide for evaluating the reasonableness of this proposal and the new rates adopted during the public review process. These policy guidelines are intended to ensure that the utility satisfies its rate review objectives for financial strength and fair and equitable rates, among others. Austin Energy's measurement of these metrics is included in Section 9 of this report along with the findings and recommendations of this study.

Table 1.3
Rate Review Policy Goals and Metrics

Policy Goals	Metrics
Achieve Revenue Requirement	Revenues sufficient to fund core functions & strategic objectives.
Align with Cost of Service (minimize subsidies across customer classes)	No customer class pays greater than 105% or less than 95% of its cost of service.
Provide Affordable Energy (mitigate impacts within customer classes)	○ No residential customer electric bill below 1,500 kWh to increase by more than $20 per month on average. ○ Transition non-demand secondary commercial customers to demand rates.
Affordability Forecast Goal	System average rate increases of no more than 2% annually, after implementation of new rates and rate design.
Rate Benchmarking	Customer bills within the lowest 50% of comparable Texas utilities.
Customer Assistance Program	○ Increase funding by at least 100 percent to increase the numbers of customers receiving assistance. ○ Provide a Customer Assistance Program discount of $25 per month.
Achieve Long-Term Financial Stability	○ New rate design ensures utility's long-term financial strength & are in compliance with Financial Policies. ○ Improve recovery of Customer and Distribution fixed costs through fixed charge collection to at least 60%. ○ Maintains or improves credit ratings.
Maintain Renewable Energy Program Excellence (GreenChoice® & Solar)	○ Rate redesign retains national leadership position of GreenChoice®. ○ Continue solar incentives coupled with net metering rate redesign.

Section 2
CONSOLIDATION OF CUSTOMER CLASSES

A customer class is a grouping of customers with similar characteristics. In the electric utility industry, customer classes exist because the cost to serve different customers can vary substantially depending on a customer's service needs and the way in which the customer consumes electricity. For example, customers with large loads (i.e., large commercial and industrial) tend to use energy in larger amounts than residential and small commercial customers and more consistently during the day, which impacts the cost to serve these customers. Correspondingly, the cost to deliver electricity to a very large commercial or industrial customer is different from the cost to deliver electricity to a residential home. The industrial customer may receive electricity from a single high-voltage line that extends directly from a substation while a home receives its electricity from a series of lines that start from a substation and eventually reach the home.

Typically, customers are grouped together into classes based upon common service requirements and electricity usage characteristics. Because the cost to serve customers with shared characteristics tends to be similar, customer classes were formed to bill groups of customers in a common manner. A utility must evaluate its customer classes and make any necessary adjustments to its customer classes before completing the cost of service study. This ensures that the cost of service analysis produces accurate and meaningful results.

Since AE's 1994 rate review, the number of customer classes and price offerings within customer classes has expanded and become increasingly complex. Currently, AE supports 24 distinct customer classes and nearly 90 unique price offerings. After reviewing the service requirements and electricity usage characteristics for customers within each of the existing 24 customer classes, AE and its rate consultants determined that many of these customer class distinctions were unnecessary and not consistent with industry best practices for designing customer classes.

Austin Energy evaluated an extensive amount of customer data, including billing data and load research, to redesign customer classes based upon industry best practices. Austin Energy is recommending that customer classes be consolidated from 24 to nine customer classes to better recognize the underlying cost of service for each class, to create meaningful cost of service differentials between customer classes, and to better align with the best practices of other Texas electric utilities.

This section of the report provides background on the need for AE's customer class consolidation, data and information analyzed to determine the proposed customer class design, and an overview of the proposed customer classes. Cost of service results and the proposed rates are presented in this report for each proposed customer class. Optional rates for residential and commercial and industrial customers, respectively, are provided for each customer class and presented in Sections 6 and 7 of this report. Multiple rate classes have been designed within the lighting customer class to address cost differences exhibited by different types of lighting and are presented in Section 8 of this report.

Need for Customer Class Consolidation

Austin Energy has recognized the need to consolidate its customer classes for several years. Since AE's 1994 rate review process, the number of customer classes and rate classes has expanded and become increasingly complex. A customer class is a group of customers with similar customer and usage characteristics, while a rate class is a group of customers charged a similar rate. Within a customer class there may be several applicable rates or rate classes. Rate classes have been developed to support new programs such as GreenChoice and other specific customer needs. All rate offerings of the utility are described in the utility's electricity tariff. An electricity tariff is a schedule of fees or prices that relate to the receipt of electricity from a specific provider such as AE. The current AE tariff identifies 24 distinct customer classes and nearly 90 unique price offerings from AE. This level of complexity suggests that AE should consolidate its customer classes to align with meaningful differences in customer service and usage characteristics giving consideration to AE service offerings available to each customer class.

Analytical Tools for Designing New Customer Classes

The process of creating new customer classes is iterative. Austin Energy first analyzed customer data to determine the initial set of customer classes on which to conduct the cost of service analytical process. Customer data includes service voltages, metering capabilities, customer monthly demand and energy requirements, and hourly load shapes. Customer data was derived from billing data and load research maintained by AE staff. Customer data facilitates the grouping of customers based upon similarities that impact the cost to serve customers. The new customer classes were ultimately validated by the cost of service analysis (i.e., different customer classes exhibited differences in the cost to serve them).

Billing Data Analysis

The use of billing data allows one to analyze consumption, or customer usage, for all customers in a given year. This information is helpful both with customer class design as well as calculation of revenues under current and proposed rates to ensure sufficient future cost recovery. Billing data can be sorted for any group of customers or customer class by usage levels to create what is often referred to as a bill frequency distribution. Bill frequency data is used to show monthly electricity usage characteristics of customers by amount of usage. When using bill frequency charts to develop customer classes, an analyst considers the variation in electric bills over the course of the year due to seasonal changes in consumption and system demand typically caused by changes in the weather that impact electricity consumption levels.

Load Research Analysis

Load research, the measurement and analysis of customer electric loads over time, allows a utility to further analyze customer electricity usage characteristics in relation to system load characteristics. The peak demand of a utility, a major driver for certain costs of the utility, is driven by the combination of load patterns for the customer classes. Each customer class may have a distinctive daily and seasonal load profile which cannot be determined by billing data alone. Load research requires certain special metering equipment be installed to measure loads.

Austin Energy maintains a rigorous Load Research Program for a variety of purposes. Austin Energy's Load Research Program allows the utility to study the way customers use electricity over the hours of a day and across seasons. This data is helpful in cost of service studies, rate tariff and pricing studies, customer and system load forecasts, resource planning and distribution system planning, and analysis of the impact of demand-side management programs such as energy efficiency programs. Specifically for this rate review, load research data was valuable in the identification of new customer classes, the normalization of TY loads and supporting power supply costs, and the allocation of demand and energy costs to each customer class.

Load research data is developed from statistical samples of demand and energy for AE's current customer classes and major customer groups using methods consistent with statistical principles and standard practices as discussed in the Association of Edison Illuminating Companies ("AEIC") Load Research Subcommittee's Load Research Manual. Load research data has been gathered for most AE customer class samples for a number of years, and the samples have been reviewed and adjusted if necessary at the end of each year to insure statistical significance. All AE rate classes are represented in AE's Load Research Program. For the cost of service analysis class load research data was aggregated into the proposed customer classes.

Austin Energy uses the LodeStar load research program (now known as Oracle Utility Load Analysis), a nationally recognized software package for this process. Sample data is used to calculate hourly average profiles for AE's customer groups, which are then multiplied by class populations to estimate class hourly loads. The class hourly loads are adjusted for estimated line losses, based on the connection voltage in which customers in the class receive service (i.e., transmission, primary, or secondary service level) and then summed and compared with AE's hourly net to system generation, or system load. The class hourly estimates are further adjusted for sampling error (the difference between samples' summed estimates and system load), based on sample types; fully metered samples, where all customers in a class are metered, do not receive sampling error adjustments. The final product of this data analysis is hourly class estimates which sum to AE's system load as well as average customer load profiles for each class. The analyst can then measure load diversity, or the amount of variation between individual customer or customer class loads with the system peak. A customer or customer class' peak can be measured in terms of coincidence with the system peak, a measure known as coincident peak, or the class maximum peak regardless of the system peak, a measure known as non-coincident peak. These measures will be discussed later in this report as they apply to the cost of service analysis.

Consistent with AEIC standards, AE's objective is to design customer class samples with a sample accuracy of +-10 percent at a 90 percent confidence level. Austin Energy meets this objective for five of the nine proposed customer classes that are metered as shown in Table 2.1. Table 2.1 shows the relative precision of the sample during the four summer peak demand months of June through September. Customer classes with higher sample errors are reflective of greater diversity in usage characteristics within the class.

Table 2.1
AE Sample Errors at a 90 Percent Confidence Interval

Class	Source	Average Sample Error (%)
Residential	Sample	7.7
Secondary Voltage <10 kW	Sample	13.9
Secondary Voltage 10 - <50 kW	Sample	8.2
Secondary Voltage ≥50 kW	Sample	11.3
Primary Voltage <3 MW	Sample	10.4
Primary Voltage 3 - <20 MW	Sample	8.2
Primary Voltage ≥20 MW	100% Sample	0.0
Transmission Voltage	100% Sample	0.0
Service Area Street Lighting	Estimated	n/a
AE-Owned Private Outdoor Lighting	Estimated	n/a
Non-Metered Lighting	Estimated	n/a
Metered Lighting	Sample	19.7

On a total system basis, for each month of the TY, estimated class demands compared to system demands are within +/- 5 percent as shown in Table 2.2.

Table 2.2
Sum of Class Coincident Demands Compared to Actual System Peak (TY 2009)

Month	Sum Hourly Class Demands / Net-To-System Demand (%)
Oct-08	104.1%
Nov-08	102.1%
Dec-08	98.8%
Jan-09	103.0%
Feb-09	104.4%
Mar-09	98.4%
Apr-09	99.9%
May-09	96.8%
Jun-09	96.6%
Jul-09	99.2%
Aug-09	97.1%
Sep-09	105.4%

Load research data used for this rate review is based on FY 2009 data for October 2008 through September 2009, adjusted for normal weather patterns and year-end customer count. Fiscal Year 2010 load shape data from new samples of specific subgroups within the residential class was used to capture the hourly impacts of (1) customers receiving discounts under AE's Customer Assistance Program and (2) solar customers. Data from these samples has been used to augment the FY 2009 residential customer class load research data. Analysis of 2010 data improved the accuracy and relevancy of the load data for these subgroups.

Customer Data Analysis

Customer data analyzed by AE provided information on the following two categories that were considered in customer class design:

- Electricity usage characteristics
    a. Energy Consumption (kWh);
    b. Peak demand (kW);
    c. Load factor; and
    d. Load profiles.
- Service requirements
    a. Infrastructure needs represented by connection voltage;
    b. Metering technology; and
    c. Customer service needs.

Customer data was derived from billing and load research data for the normalized TY to align with the financial records used as the basis for the historical TY of the cost of service study. The objective of the statistical analysis of billing data, load research, and other customer profile data is to group customer with similar service requirements and other electricity usage characteristics.

Electricity Usage Characteristics

Electricity usage characteristics reflect the way individual customers and customer classes use electricity. Austin Energy looked at a customer or customer class's usage profile to determine patterns that help consolidate customers into common groups, or customer classes. Measures of electricity usage show when and how much demand is placed on the system by a customer or customer class, how consistent their level of power use is (load factor), and what their average amount of electricity used over each hour of the day is (load profile).

The two primary measures of electricity usage are demand and energy. Demand is the measure of power in kilowatts ("kW"), used at a specific point in time. Energy kilowatt hours ("kWh") is the measure of customer electricity usage over time. The customer's pattern of usage is best represented by a load profile. Industrial and large commercial classes tend to have larger loads and, use energy more consistently than residential customers. The relationship between these two measures (demand and energy), known as load factor, was also an important consideration used by AE in developing proposed customer classes. These types of measures are discussed in more detail below.

Consumption

Electricity consumption is a usage characteristic that was considered in developing AE's proposed customer classes. Consumption can be measured annually, seasonally, monthly, daily, hourly, and even in 15-minute intervals if the required metering equipment is in place. Average consumption is measured as well as variability in consumption over the course of the day, month, season, or year. This information can be profiled using a load profile discussed below.

As discussed above, AE analyzed and normalized billing data for each current and proposed customer class to determine average monthly electricity consumption. Bill frequency distribution charts were developed based on actual FY 2009 data. Variation in consumption over the course of the year is expected due to seasonal changes in usage caused by changes in the weather.

Peak Demand

Peak demand refers to the maximum demand placed on the system by a customer or group of customers and is a primary determinant of the cost to serve customers. Austin Energy plans its transmission and distribution infrastructure and power generation resources to meet the peak demand. Customers who have a greater contribution to the system peak require AE to make a greater investment in infrastructure and generation to serve peak load. This contribution is referred to as a coincidence. Customers that are highly coincident with system peak (in other words, have high loads at the same time the system peaks) are more costly to serve than are customers who do not contribute significantly to the coincident peak. When two customers consume the same amount of electricity in a given month, the cost to serve the customer whose demand contributes significantly to the system peak is greater than the cost to serve the customer whose demand does not contribute as much to the system peak.

The contribution of different customers or groupings of customers to overall system demand can be measured in different ways. Non-coincident peak ("NCP") demand and coincident peak ("CP") demand are two meaningful measures of the impact of a customer or group of customers on the investments needed to maintain the electric system. Coincident peak demand is the power needed by a customer or group of customers during the period of highest electricity usage for the overall system. Non-coincident peak demand is the maximum power needed to serve a customer or group of customers during a particular time period regardless of the overall system peak demand. Coincident peak demand is an important consideration in planning for power generation and transmission facilities while NCP demand tends to drive distribution and customer-specific investments. These measures are summarized below.

Table 2.3
Demand Measurements by Customer Class
(TY 2009)

Classes	CP (kW) August	NCP (kW)	Billed Demand (kW)
Residential	987,789	1,194,076	22,668,750
Secondary Voltage <10 kW	82,121	99,100	1,155,332
Secondary Voltage 10 - <50 kW	244,672	257,114	3,000,305
Secondary Voltage ≥50 kW	863,190	909,375	10,370,350
Primary Voltage <3 MW	64,703	70,815	935,115
Primary Voltage 3 - <20 MW	100,952	110,081	1,195,446
Primary Voltage ≥20 MW	120,016	126,283	1,431,533
Transmission Voltage	29,410	51,459	408,622
Service Area Street Lighting	90	9,470	124,124
AE-Owned Private Outdoor Lighting	0	4,595	45,263
Non-Metered Lighting	6	643	6,677
Meter Lighting	451	4,187	17,064
Total	**2,493,400**	**2,837,197**	**41,358,581**

Load Factor

Load factor measures the consistency of power usage over time and is a measure of end-user efficiency. A measurement of the relationship between demand and energy, load factor is the ratio of the average load supplied to a customer's peak (in kW) during a specific period of time. Load factor is expressed as a percentage, with higher load factors representing greater efficiency from a system engineering perspective.

Customers with higher load factors tend to have a lower cost of service per unit of energy consumed because fixed utility expenses are spread over more units of billed electricity usage.

Load factor is calculated by dividing actual electricity consumed over a period by a customer's theoretical maximum energy. Theoretical maximum energy is just maximum demand times the number of hours in that same period. For example, if a customer had a peak demand of 6 kW for a given year and consumed 26,280 kWh over the course of the year, their load factor would be 50 percent, as shown below.

Theoretical maximum energy

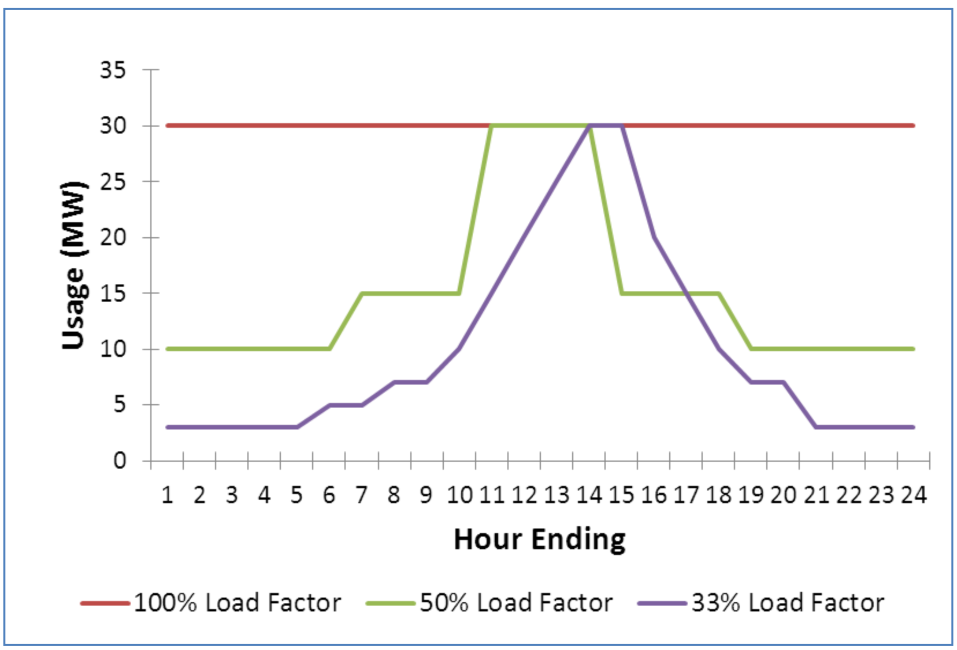
6 kW x 24 hours x 365 days in a year = 52,560 kWh

and dividing that value by the actual consumption:

26,280 kW / 52,560 kWh = 0.50 or 50 percent

Figure 2.1 illustrates different electricity consumption patterns over the course of the day for customers with various load factors, but all profiles have the same maximum, or peak demand, of 30 megawatts ("MW"). While a customer with a lower load factor, such as the 33 percent and 50 percent profiles in Figure 2.1, uses less overall energy (the amount of space below their respective line of usage), they have a similar impact on system demand.

Figure 2.1
Various Load Factors for a 30 MW Customer



The concept of load factor is most easily understood by using the common light bulb as an example. Assume a 60-watt light bulb is turned on and off (just once) instantly over the course of an entire month. That light bulb places 60 watts of demand on the system. Austin Energy must have in place enough infrastructure to ensure that the light turns on whenever called upon. Because AE never knows when the customer will flip the light switch, it must have the necessary infrastructure and generation facilities to serve that need. This requires a significant investment in power plants, wires, and personnel. In this example, the efficiency of the end-user is poor as the light was only on for an instant. The bulb placed a 60-watt demand of the system but used very little energy. In this case, the load factor associated with the bulb is practically 0 percent.

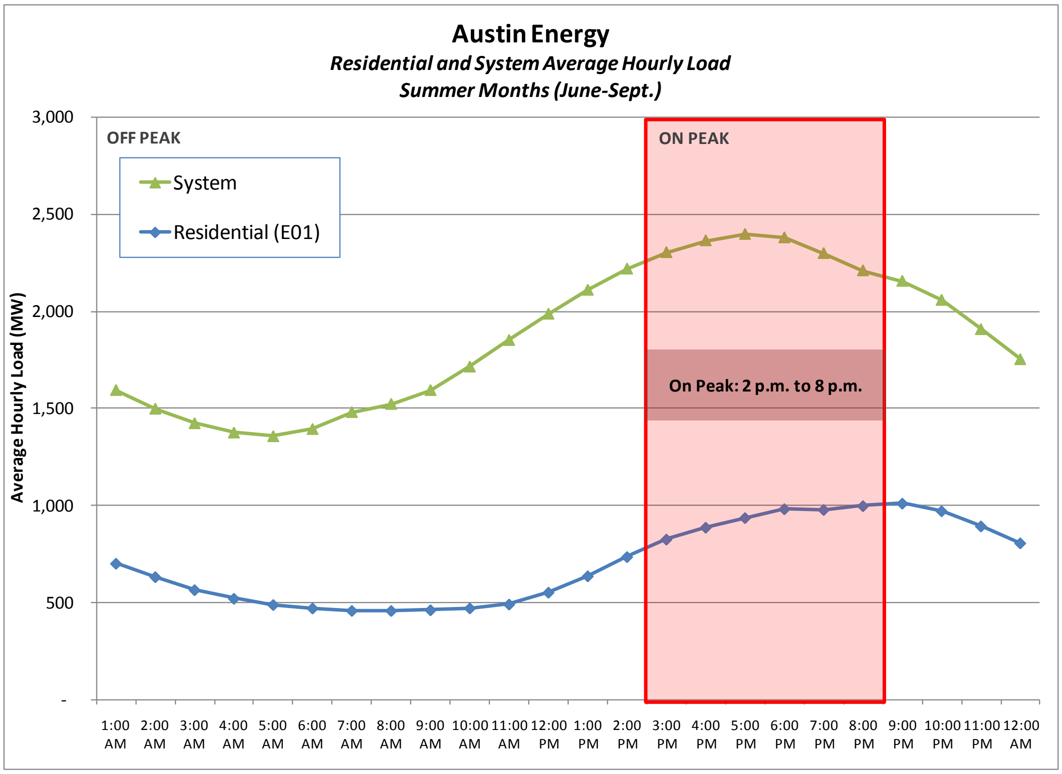
Now assume that the light bulb is turned on and left on continuously for an entire month. The demand placed on the system is still 60 watts. However, the energy used by the light bulb during the course of the month is 60 watts multiplied by 730 hours (average hours in a month) or 43.8 kWh. To keep the light on over time, utility power plants powered by non-renewable resources must burn fuel. In this scenario, the light bulb is as efficient as possible from an engineering perspective as the light bulb is on all the time and the associated demand on the system remains constant over the entire month. In this case, the load factor associated with the bulb is 100 percent.

If we assume that the owner of this light bulb is charged on a per kWh basis for service, the load factor of the light bulb is critically important to the utility's ability to recover its costs. In the case of the low load factor customer, AE has only one billing hour during the entire month to recover its fixed costs, if the rate charged is based on energy only (cents per kWh). As a result, low load factor customers usually pay less than cost of service under an energy-only rate structure. However, in the case of the high load factor customer, fixed costs can be recovered over all 730 hours in the month. Thus, high load factor customers usually pay more than their cost of service under an energy-only rate structure. To address the variability in customer load factor and equitable cost recovery, utilities frequently implement a demand and energy rate structure. Properly designed rates that include a demand and energy charge recover costs appropriately from customers with varying load factors. Regardless of the customer's mix between demand and energy, the customer always pays the appropriate amount as the demand charge recovers the fixed cost associated with the utility providing the customer sufficient capacity and the energy charge recovers the variable costs the utility incurs to produce energy. Most customer classes have load factors ranging from 20 to 80 percent with infrequent users of electricity having low load factors and heavy users having high load factors.

Load Profile

A load profile examines how customers or groups of customers use power at different times of the day and year. Figure 2.2 illustrates the load profile of AE's residential customer class and the system as a whole for a typical summer day in TY 2009. The horizontal axis indicates the hour of the day. The vertical axis shows the amount of load (in MW) used in each hour on an average summer day.

Figure 2.2
Austin Energy Example Hourly Load Profile for Residential Customers FY 2009



The profile in the figure above for a peak summer day indicates that both residential and system load, or hourly demand, increases slowly throughout the day until it peaks in the late afternoon or evening hours. Residential customers tend to use electricity in a similar manner which supports grouping all residential customers into one class. Figure 2.2 shows residential peak demand for a peak summer day diverging slightly from the system profile, with the residential customer class demand starting to rise at 10 a.m., peaking between the hours of 6 p.m. and 9 p.m., and dropping until residential demand reaches minimum levels around 7 a.m. to 10 a.m.

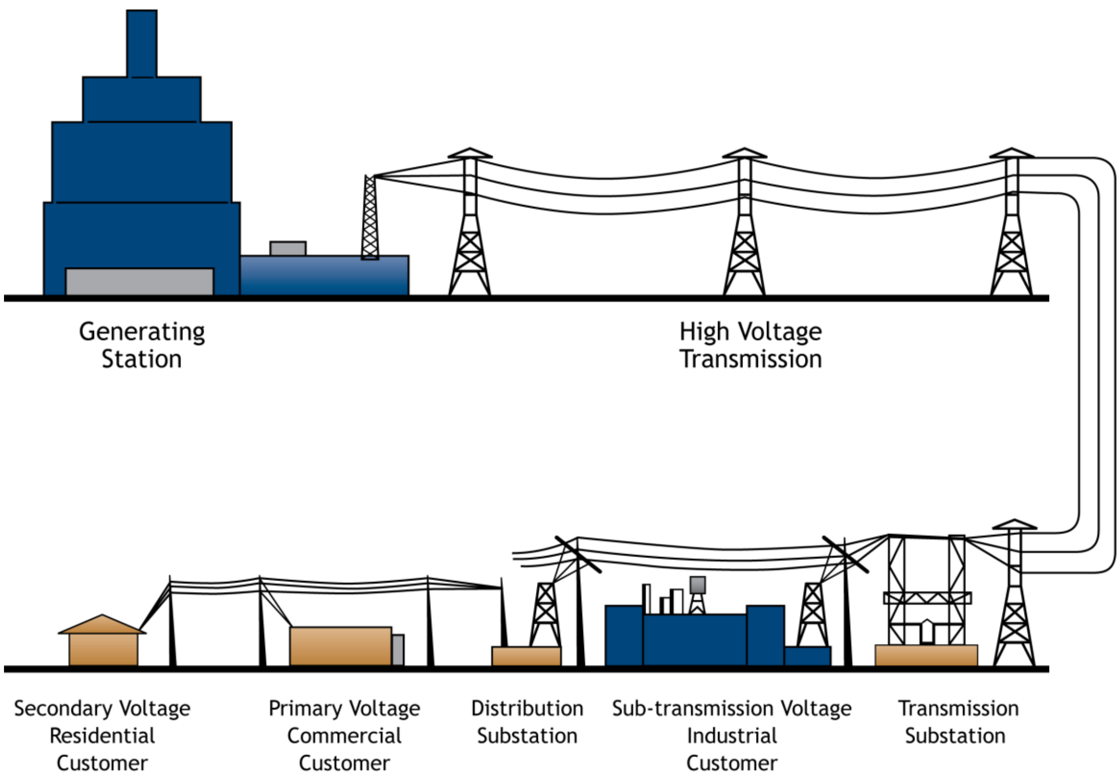
Service Requirements

Service requirements refer to the infrastructure required to deliver power at a required level (voltage) to a customer as well as their metering and the customer service needs. For instance, some very large companies in AE’s service territory receive their electricity through a power line that goes directly from a substation to the company. By contrast, homes receive their electricity through a complex series of power lines and equipment known as the distribution system. Installing and maintaining the infrastructure to deliver power to secondary voltage customers (e.g., residential customers) is more costly per unit than delivering power to primary or transmission voltage customers and this difference must be accounted for when grouping customers into customer classes.

Infrastructure Needs and Connection Voltage

Different customer types require specific infrastructure that is typically determined by the voltage level at which the customer connects to the system. Some large commercial and industrial customers take service at a higher voltage (primary or transmission), bypassing certain lower voltage (secondary) elements of the distribution system. Lines and wires that extend to other commercial customers and all residential customers are not needed to support customers who take service at the primary or transmission voltage level. These customers have made capital investments in infrastructure to take service at this level such as purchasing their own transformers. Since customers taking service at the primary or transmission voltage level are using only some parts of the electric system, they typically have a lower cost of service for fixed cost components of the system. For these reasons, mixing customers of different voltage levels in the same class is not advised and AE is not proposing to do so. The typical electric system infrastructure needs for different types of customers are illustrated by Figure 2.3.

Figure 2.3
Electric System Diagram



Power Factor

Power factor is another measure of efficiency that reflects the amount of real power delivered and used by a customer. Power factor is the ratio of real power delivered to a customer to total (or apparent) power produced by the utility. Real power is electricity that can actually be used to perform work such as running a motor or heating an oven. Total power is the amount of electricity the utility must produce and delivery to a customer to operate the customer's machinery and equipment. If uncorrected, a portion of total power is consumed by motors and other devices on a customer's premises before the equipment is capable of performing real work. This result causes real power to be less than total power and is inefficient. For an equivalent amount of real power, customers with low power factors require more electricity to be delivered by a utility than high power factor customers. The delivery of more electricity results in greater system losses and requires the utility to install additional capacity, at additional cost, throughout the electric system. Therefore, customers with lower power factors have a higher cost to serve. This higher cost of service is reflected in the rate structure via a power factor adjustment. This adjustment is discussed in Section 5 of this report. By installing devices near their equipment, such as capacitors, a customer can improve their power factor. Such an improvement in power factor will result in a lower monthly customer electric bill.

Metering Technology

Different types of customers require particular metering technology and meter data management needs to support billing and analysis. All AE customers currently have automated meters, meaning that data is automatically collected and transferred to a central database for billing and analysis. This automation saves trips to manually read meters which can lead to reduced costs for fuel, vehicles, and personnel as well as reduced liability related to entering properties. Some of AE's automated meters use one-way wireless technology and others have two-way wireless technology which impacts the capabilities to both send and receive data in real-time. Often, this type of advanced metering infrastructure is referred to as a "smart grid." Specific meters are typically grouped into three categories:

- Standard Kilowatt-Hour (kWh) Meter – A meter that only measures and records a customer's monthly energy consumption.
- Standard Demand Meter – A meter that measures and records a customer's maximum monthly, or peak, demand and monthly energy consumption.
- Interval Demand Recording Meter – A meter that measures and records a customer's demand at 15-minute intervals.

Customer Service Needs

Customer service needs consider the level of customer service support AE must provide to different customer types in order to achieve excellent customer service. For instance, due to the large number of customers and their generally less stringent power requirements, the residential customer class typically exhibits a unique set of customer service needs. Likewise, large commercial and industrial customers often have special reliability and customer service needs that require additional support from the utility.

Service Requirements for Current Customer Classes

Table 2.4 provides a matrix representation of the various service requirements described above for each of AE's current 24 customer classes, demonstrating that many of AE's customer classes overlap in terms of service requirements. This suggested a need to consolidate some customer classes.

Table 2.4
Existing Austin Energy Customer Class Service Requirements TY 2009

		Service Connection								
		Meter			Service Voltage			Electric Service Type		
Customer Class	**# of Cust.**	**AMR**	**Demand**	**IDR**	**Secondary**	**Primary**	**Trans**	**Firm Service**	**Interruptible Service**	**Stand-by Service**
Residential	365,140[3]	√			√			√		
General Service Non-Demand	33,341	√	√		√			√		
General Service Demand[1]	10,097	√	√		√			√		
Primary Service	60	√	√	√		√		√		
Large Primary Service	24	√	√	√		√		√		
Transmission Service	3	√		√			√	√		
State General Service Non-Demand	199	√	√		√			√		
State General Service Demand	245	√	√		√			√		
State Primary Service	6	√	√	√		√		√		
State Large Primary Service	5	√	√	√		√		√		
Ind. School Districts General Service Demand	12	√	√		√			√		
Ind. School Districts Time-of-use	254	√		√	√			√		
Texas Dept of Transportation Sign and Street Lighting	1	√			√			√		
Water and Wastewater	178	√	√	√	√	√		√		
Other City	693	√	√		√			√		
Street Lighting and Traffic Signals	5				√			√		
Security Lighting	Multiple				√			√		
Non-Metered Outdoor Lighting	Multiple				√			√		
Primary Standby Capacity	2	√				√				√
Transmission Standby Capacity	1	√					√			√
Economic Development	0	√	√	√		√		√		
Residential Time-of-Use[2]	0	√		√	√			√		
Interruptible Service	0	√	√	√		√			√	
Unmetered Non-Demand Commun-ications Equipment	0				√			√		

Notes:
1. Includes all secondary meters for special contract customers.
2. Closed to new participants.
3. Sum of Residential customers and worship facility customers.

Customer Data Analysis Findings

The data provided in Table 2.4 above demonstrates customer class similarities and differences in service requirements. In addition, Table 2.5 below summarizes similarities and differences in electricity usage characteristics by customer type. Please note that this listing of customer types is different from the listing of customer classes and is intended to show the primary differences in customer profiles by customer type which is how customers tend to identify themselves. The findings of this analysis are described below under groupings of the major customer types.

Table 2.5
Electricity Usage Characteristics By Existing Customer Type TY 2009

Customer Type	# of Customers	Average Monthly Load Factor (%)	Average Energy per Customer (kWh)	Average Max Demand per Customer (kW)
Residential [1]	354,602	23.3	883	5.2
Residential Worship Facilities	619	23.7	6,286	36.1
General Service Non-Demand	33,341	49.8	1,236	3.4
General Service Demand	10,046	50.4	31,378	84.9
Independent Schools	266	38.7	76,313	269.0
State	455	66.6	100,862	207.2
Water and Wastewater	178	73.9	100,414	187.2
Primary Service	60	65.7	311,869	647.6
Special Contracts	76	87.4	2,343,896	3,672.9

Note:
1. Residential usage characteristics exclude 9,919 Customer Assistance Program participants due to insufficient data.

Residential

Austin Energy's existing Residential customer class includes residential, residential low-income, and worship facility customers. Electricity usage for residential customers tends to vary by season with usage substantially higher in the summer months. Customer profile data for these three types of customers indicate that residential and residential low-income customers have similar characteristics. However, worship facility customers show a substantial difference in electricity usage characteristics compared to residential customers. Worship facility customers place larger demands on the system, consume more total electricity, and consume a greater proportion of their electricity during off-peak hours than do residential customers. Worship facility customers exhibit characteristics more similar to non-residential customers with secondary service, an indication that worship facility customers should be removed from the Residential customer class and placed into the appropriate Secondary Voltage customer class for commercial customers.

General Service Non-Demand

Existing General Service Non-Demand customers are mostly small business customers or small commercial offices with electricity usage characteristics similar in size to residential customers. These customers take power at secondary voltage and have demand, total electricity consumption, and contribution to the system peak at levels only slightly higher than residential customers. However, businesses that operate during typical business hours (8 a.m. to 6 p.m.) tend to have load profiles that are different from residential customers. Other differences between general service non-demand and residential customers is class size and customer service needs. The existing general service non-demand class has significantly fewer customers than the residential class. Additionally, general service non-demand customers have a wide variation in usage characteristics such as monthly load factor. These differences justify the continued separation of small non-residential customers into a customer class that is distinct from residential customers as well as from mid-sized and large commercial customers. However since AE is able to bill all non-residential customers for demand, AE is proposing eliminating all non-demand small commercial customer classes and grouping those customers into the appropriate Secondary Voltage customer class that is subject to a demand charge.

General Service Demand

Currently the general service demand class encompasses customers with demands ranging from just over 20 kW to almost 2,800 kW, a difference in peak demand of over 100 times. Presently, customers with a demand of at least 20 kW served at the secondary service voltage level are grouped under the same customer class as customers with a demand of several MW who are served at the secondary voltage level. This means that customers with relatively high demand and consumption such as a high-rise office building, hospitals, and hotels are grouped with customers with relatively low demand such as fast food restaurants, gas stations, and small retail businesses.

The cost to serve customers within this existing class can be materially different depending on the customer's demand. This can be corrected by breaking secondary voltage service into multiple classes based on customer peak demand. Customer maximum demand requirements, class load factor and class coincident factors are important cost of service differentiators. For general service demand customer's average demand per customer, monthly load and coincident factors are shown in Table 2.6.

Table 2.6
General Service Demand – TY 2009

Customer Class	Demand per Customer	Average Monthly Load Factor (%)	Coincident Factor (CP/NCP)
Secondary Voltage <10 kW	3	45	0.83
Secondary Voltage 10 – <50 kW	24	45	0.95
Secondary Voltage ≥50 kW	269	55	0.95

Analysis of customer energy usage and demand indicate that break points at 10 kW and at 50 kW help distinguish cost of service differentials for these customers. The Secondary Voltage ≥50 kW customer class has significantly larger demand requirements, higher average monthly load factor and the highest coincident factor of the three subgroups compared in the above table. However, the Secondary Voltage <10 kW and the Secondary Voltage 10 – <50 kW customers exhibit similar characteristics except the average customer in the Secondary Voltage <10 kW class is significantly smaller than the average customer in the Secondary Voltage 10 – <50 rate class. As a result of the size differential, distribution costs per customer are greater for the larger general service sub-groups. In total, the cost of service differentials between these three customer subgroups is meaningful as described in greater detail in Section 4.

Primary Service

Distinct differences in service requirements and costs for being served at a primary connection voltage level justify maintaining separate customer classes for Primary Voltage customers. As with commercial customers being served at the secondary service voltage, customers served at the primary voltage level can vary in size considerably, with some customers having demand of less than 1 MW and others of greater than 20 MW. Analysis of distributions of customer energy usage and demand indicate that break points at 3 MW and 20 MW help distinguish cost of service differentials for these customers. Customer maximum demand requirements, class load factor and class coincident factors are important cost of service differentiators. For primary service customers average demand per customer, monthly load and coincident factors are displayed in Table 2.7.

Table 2.7
Primary Service Demand – TY 2009

Customer Class	Demand per Customer	Average Monthly Load Factor (%)	Coincident Factor (CP/NCP)
Primary Voltage <3 MW	764	59	0.91
Primary Voltage 3 - <20 MW	4,981	88	0.92
Primary Voltage ≥20 MW	Confidential	Confidential	Confidential

The table above indicates that as primary service customers' demands increase, average monthly load factors increase significantly. Coincident factors for all three sub-groups are similar. Because of the size and load factor differentials, these sub-groups have meaningful cost of service differentials.

Transmission Service

Austin Energy's existing Transmission Service class is designed to provide service to customers receiving electric service at the transmission voltage level. Since customers in this class receive service at the transmission voltage level they bypass AE's distribution system and should be distinguished as a separate customer class.

City, Schools, State, and Water and Wastewater Customers

Currently, AE has designed unique customer classes for City of Austin, independent school districts, state, and water and wastewater customers. Basing customer classes on ownership rather than shared characteristics is counter to industry best practices for customer class design. Customer data for these current customer classes indicate that these customers should be merged into the appropriate secondary or primary voltage customer class for commercial customers depending on the voltage level at which they receive service, and the demand they place on the system as with all other commercial and industrial customers.

Special Contracts

Through May 2015, several of the largest commercial and industrial customers served by AE are under contract to receive service at a discount rate. Large customers are served under this special contracts to support economic development. These customers provide benefits to the community in terms of providing a large numbers of jobs and other economic stimulus benefits. Customer profile data suggests that these customers be placed into their appropriate customer class upon expiration of their contracts or that their contract be re-negotiated based on the cost of service analysis results.

Benchmarking Customer Classes in Texas

To validate the reasonableness of the proposed customer classes, AE benchmarked the customer classes of several utilities in Texas as a consideration for the proposed design. Table 2.8 lists the proposed customer classes with the classes of five utilities in Texas. CPS Energy is the only municipally-owned utility included in the table as this is the only public power utility in Texas of comparable size to AE. Oncor, CenterPoint Energy, AEP Texas North, and AEP Texas Central are the largest investor-owned utilities providing transmission and distribution service in the Electric Reliability Council of Texas ("ERCOT") electric system operating region. Investor-owned utilities are regulated by the Public Utility Commission of Texas ("PUCT") and pass on charges solely for transmission and distribution (or "wires") services to customers being served in the competitive market areas of Texas. Regulated utilities must gain approval for their customer classes by the PUCT.

Table 2.8
Comparison of Proposed AE Customer Classes and Texas Electric Utility Customer Classes as of March 2011

Customer Class	Austin Energy	CPS Energy	Oncor	Center Point	AEP Texas North	AEP Texas Central
Residential Service	√	√	√	√	√	√
Residential All Electric Service		√				
General Service		√				
Extra Large Power (>1 MW)		√				
Large Lighting and Power		√				
Secondary Voltage ≤10 kW w/o demand			√	√	√	√
Secondary Voltage <10 kW w/ demand	√					
Secondary Voltage >10 kW			√	√	√	√
Secondary Voltage 10 - <50 kW	√					
Secondary Voltage ≥50 kW	√					
Primary Voltage				√		
Primary Voltage ≤10 kW			√		√	√
Primary Voltage >10 kW			√		√	√
Primary Voltage <3 MW	√					
Primary Voltage >3 MW - <20 MW	√					
Primary Voltage ≥20 MW	√					
Transmission Voltage	√		√	√	√	√

All of the utilities in Table 2.8 have a separate residential service customer class, transmission service class, lighting services class, and classes based on connection voltage for other customers. Also, notice the impact of the competitive retail market design on customer class designations. Customer class designations are uniform for all investor-owned utilities other than Oncor and AEP's distinction of lower than 10 kW Primary Service customers (a rare occurrence) and are based solely on service requirements. This is a by-product of regulation by the PUCT as these utilities now only provide wires services. Class differences are based only on metering technology and service connection voltage. Retail Electric Providers ("REPs") provide electric service to customers in the competitive markets and pass on the bundled wires service charges to customers along with their customer service offerings and energy price offerings. This is typically provided at an "all-in" price offer to customers in competitive markets. Retail Electric Provider customer classes are broad and simple with only residential and commercial class designations. As a municipally-owned utility in Texas, CPS Energy offers full bundled service to its customers in the same way as AE. CPS Energy currently has only five customer classes. These customer classes primarily consider customer size and service requirements. CPS Energy's customer classes are comparable to those of the investor-owned utilities.

Austin Energy's proposed customer classes similarly designate non-residential customers based upon service connection voltage and demand. The key difference between AE and other large electric utilities in Texas in their customer class distinctions is AE's further designation of commercial and industrial customers based on the customer's demand on the system.

Proposed Customer Classes

Based on review of the customer data and benchmarking described in this section of the report, AE recommends that the existing 24 customer classes be consolidated into the nine customer classes described below. Service connection voltage, customer demand and load factor where found to be the most distinguishing characteristics that created cost of service differentials. For this reason, customer classes are distinguished by the level at which they connect to the system and, in the case of residential customers, the class's customer service needs. Larger customers tend to have higher load factors, a key determinant in cost of service results as discussed earlier in this section. Additionally, because substantial variation exists in customer demand for customers served at the secondary voltage level and primary voltage levels, the secondary voltage and primary voltage customer classes are further defined by demand on the system to account for this cost of service differential.

Residential

Austin Energy is proposing the continuation of the Residential customer class with worship facilities removed and placed in their appropriate customer class listed below. The residential customer class is by far AE's largest existing customer class in terms of number of customers served. Although service requirements and some electricity usage characteristics for residential customers in certain circumstances are similar to smaller non-residential secondary voltage customers, the size and customer sophistication of this group of customers warrant a separate class. Electricity usage patterns are also unique to this group of customers.

Secondary Voltage < 10 kW

Non-residential Secondary Voltage <10 kW customers represent the smallest commercial businesses and are currently grouped in the General Service Non-Demand customer class. Creating a break point at 10 kW improves the comparability of customers in this customer class with other customers in ERCOT as this aligns AE with ERCOT utilities operating in the competitive market in Texas. Although customers in this class have not historically been billed for demand, they do have demand meters in place, and demand charges are being recommended in the design of rates for this class. The proposed charges billed on demand will be phased in over a three-year period to help customers in this class adjust to the new rate structure and mitigate any rate shock for low load factor customers. The Phase 1 (Proposed Rate FY 2012) for all proposed transition rates would be implemented at the point in which new rates are approved in FY 2012 and the second and third phases would occur in either the beginning of the following fiscal years, the beginning of the following calendar years, or at a time to be determined by AE staff. All commercial and industrial customer classes would be billed for demand to improve fixed cost recovery and provide strong energy efficiency pricing signals for these customers. All businesses, worship facilities, schools, state facilities, and city facilities currently in other customer classes that meet the requirements for this class will be placed into this class rather than into a separate customer class. Customers currently with special contracts that meet this class' requirements would be placed in this customer class upon expiration of their contracts. Compared to other Secondary Voltage commercial customers, these customers have the highest cost of service due to a combination of the relatively low energy usage and low monthly load factor.

Secondary Voltage 10 kW – <50 kW

Secondary Voltage customers with demand between 10 kW and 50 kW represent mid-sized commercial businesses and are currently grouped in the General Service Demand customer class for customers with peak demand greater than 20 kW and the General Service Non-Demand customer class for customers with peak demand between 10 kW and 20 kW. The proposed charges billed on demand for customers in this class who currently do not have demand charges will be phased in over a three-year period to help those customers adjust to the new rate structure and mitigate any rate shock for low load factor customers. The Phase 1 (Proposed Rate FY 2012) for all proposed transition rates would be implemented at the point in which new rates are approved in FY 2012 and the second and third phases would occur in either the beginning of the following fiscal years, the beginning of the following calendar years, or at a time to be determined by AE staff. Customers in this proposed class have a wide range of monthly load factors and usage, but in general these customers have load factors higher than customers in the Secondary Voltage <10 kW customer class. All businesses, worship facilities, schools, state facilities, and city facilities currently in other customer classes that meet the requirements for this class will be placed into this class rather than into a separate customer class. Customers currently with special contracts that meet this class's requirements would be placed in this customer class upon expiration of their contract.

Secondary Voltage ≥50 kW

Secondary Voltage customers with demand equal to or greater than 50 kW represent large commercial businesses served at the secondary voltage level and are currently grouped in the General Service Demand customer class. The proposed charges billed on demand for customers in this class who currently do not have demand charges will be phased in over a three-year period to help those customers adjust to the new rate structure and mitigate any rate shock for low load factor customers. The Phase 1 (Proposed Rate FY 2012) for all proposed transition rates would be implemented at the point in which new rates are approved in FY 2012 and the second and third phases would occur in either the beginning of the following fiscal years, the beginning of the following calendar years, or at a time to be determined by AE staff. These customers, however, are significantly larger with typically higher monthly load factors than those found in Secondary Voltage customers classes with demand less than 50 kW.

Customers in this proposed class have relatively large electric bills and tend to have greater sophistication of how to manage energy use and control costs. Additionally, these customers have greater incentives to make building efficiency improvements and lower peak demand than customers of smaller size. All businesses, worship facilities, schools, state facilities, and city facilities currently in other customer classes that meet the requirements for this class will be placed into this class rather than into a separate customer class. Customers currently with special contracts that meet this class's requirements would be placed in this customer class upon expiration of their contracts.

Primary Voltage <3 MW

In addition to requiring less infrastructure, as these customer are served at primary voltage, customers served at the primary voltage level tend to be significantly larger than customers served at the secondary service level. These customers include very large commercial buildings and small to mid-sized industrial facilities. This customer class generally has higher monthly load factors than Secondary Voltage customers. All schools, state facilities, and city facilities currently in other customer classes that meet the connection voltage and demand level requirements for this class will be grouped into this class rather than into a separate customer class. Customers currently with special contracts that meet this class' requirements would be placed in this customer class upon expiration of their contract.

Primary Voltage 3 MW – <20 MW

This class includes a small number of very large commercial and industrial customers with a demand between 3 MW and 20 MW. These customers exhibit high monthly load factors and are highly sophisticated in their power usage. These customers also tend to have unique service requirements and customer service needs with a particular emphasis on reliability. Customers currently with special contracts with demand under 20 MW will be placed in this customer class upon expiration of their contract absent a re-negotiation of their contract based upon the cost of service for this class.

Primary Voltage ≥20 MW

Customers served at the primary voltage level with a demand equal to or greater than 20 MW are the largest customers served by AE and exhibit the highest monthly load factors. Underlying business operations for these customers tend to be industrial in nature. Again, there are only a few customers in this category and they are highly sophisticated in their use of power. These customers also tend to have unique service requirements and customer service needs with a particular emphasis on reliability. Customers currently with special contracts with demand of 20 MW or greater will be placed in this customer class upon expiration of their contract absent a re-negotiation of their contract based upon the cost of service for this class.

Transmission Voltage

Austin Energy recommends continuing the current Transmission Service customer class (but renaming it as Transmission Voltage). Customers in this existing class are typically large industrial customers that require service at transmission voltage as these customers own and maintain distribution substations and related infrastructure. This class includes a small number of highly sophisticated power usage customers. Customers currently with special contracts and served at the transmission voltage level will be placed in this customer class upon expiration of their contract absent a re-negotiation of their contract based upon the cost of service for this class.

Standby Service

Austin Energy recommends continuing the Standby Service customer class. Standby Service customers self-generate and take non-firm service from AE. They have an intermittent need for electricity from AE, so they tend to exhibit poor load factors from the utility's perspective. This customer class has a small number of customers who tend to be sophisticated power users.

Lighting Service

Austin Energy is consolidating its existing customer classes related to lighting into one customer class. However, within the customer class, multiple rate classes are being designed to account for differences in customer types who receive lighting services. These rate classes are described in Section 8 of this report. Lighting customers are private and public end-users that require lighting for streets, highways, security, and athletic events. Although specific infrastructure requirements may vary by types of lights supported, electricity usage characteristics tend to be relatively consistent and almost always off-peak.

Proposed Customer Class Data

Table 2.9 summarizes the electricity usage characteristics and service requirements for each of AE's proposed customer classes. More customer class data is provided in Appendix A of this report.

Table 2.9
Proposed Customer Classes - Characteristics (TY 2009)

Customer Class	Number of Customers	Average Demand per Customer (kW)	Average Monthly Energy Usage per Customer (kWh)	Average Monthly Load Factor (%)	Meter Type	Service Voltage
Residential	364,521	5	883	23	kWh	Secondary
Secondary <10 kW	32,001	3	987	45	Demand	Secondary
Secondary 10 - <50 kW	10,360	24	7,939	45	Demand	Secondary
Secondary ≥50kW	3,214	269	107,415	55	Demand	Secondary
Primary <3 MW	97	764	331,657	59	Interval Demand	Primary
Primary 3 MW - <20 MW	20	4,981	3,207,625	88	Interval Demand	Primary
Primary ≥20 MW	2	Confidential	Confidential	Confidential	Interval Demand	Primary
Transmission	3	Confidential	Confidential	Confidential	Interval Demand	Trans.
Lighting	44	3,286	92,626	35	Demand	Secondary

Notes:
1. "Number of Customers" is an estimate based on the number of bills being used in the TY divided by 12 months.
2. "Average Monthly Energy per Customer" represents the total class retail energy sales (weather normalized) divided by the number of bills in the TY.
3. "Average Demand per Customer" equals the class annual billed demand divided by the number of bills.
4. "Average Monthly Load Factor" represents the average monthly load factor based on retail energy sales and estimates of sum of maximum demands for the 12 months of the year.

Example customer types for each proposed customer class are provided in Table 2.10.

Table 2.10
Proposed Customer Classes – Example Customer Types

Customer Class	Example Customer Types
Residential	Home, Apartment, Condo
Secondary Voltage <10 kW	Small Business, Billboard, ATM, School Portable Buildings
Secondary Voltage 10 - <50 kW	Small Office, Mid-Sized Retail Business, Restaurant, Nail Salon, Small School Building, Daycare, Auto Repair Shop, Small Worship Facility, Water/Wastewater Facility
Secondary Voltage ≥50kW	Large Office, High-Rise Building, Big Box Retail, Medium-Large School or Government Building, Hotel, Soup Kitchen, Medium-Large Worship Facility
Primary Voltage <3 MW	Large Office, Large Grocery, Big Box Retail, Large School or Government Building, Small Industrial Facility, Light Manufacturing Facility
Primary Voltage 3 MW - <20 MW	Large Manufacturing, University, High Tech Facility, Large Industrial Facility, Large Government Building, Hospital, Data Center
Primary Voltage ≥20 MW	Large Industrial Facility, Semi-Conductor Facility
Transmission Voltage	Large Industrial Facility
Lighting	Street Lighting, Security Lighting, Parking Lot Lighting, Ballpark and Stadium Lighting

As noted above, this consolidation of customer classes requires that certain customers be assigned to new customer classes based on their service characteristics and level of demand on the system (in kW). In some instances, moving a customer into a new customer class may actually lower their electricity bills while in other cases their electricity bills may increase. For this reason, bill impacts for all existing customer classes are included in this report.

To assist the reader of the report with understanding these impacts, a mapping of customers classes is provided in Table 2.11, where AE's existing customer classes are mapped into the proposed customer classes. The columns on the left side of the table show the current customer classes and FY 2009 revenue in million dollars for each class. The top row of the shaded columns lists the proposed customer classes. Shaded boxes show where customers in the existing customer class would be placed in the proposed customer classes based on connection voltage and demand. Numbers in the shaded boxes represent the FY 2009 year-end monthly bills and approximate the annual number of customers for each existing customer class.

Table 2.11
Assignment of Customers from Existing to Proposed Customer Classes

		Proposed Customer Classes									
Current Customer Class	2009 Revenues ($M)	Residential	Secondary Service < 10 kW	Secondary Service ≥ 10 < 50 kW	Secondary Service ≥ 50 kW	Primary Service < 3 MW	Primary Service ≥ 3 < 20 MW	Primary Service ≥ 20 MW	Transmission Service	Lighting	Standby
Residential	$ 411.8	364,521									
Residential - Church	$ 5.0		104	448	67						
General Service - Non Demand	$ 47.9		31,284	2,021							
GS-ND Sportslighting	$ 0.3									36	
Water and Wastewater	$ 18.1		68	60	34	16					
Other City	$ 10.9		384	186	110	14					
Streetlighting and Traffic Signals	$ 7.6									5	
General Service - Demand	$ 337.2			7,461	2,585						
Primary Service	$ 10.0					53					
Primary Service - Secondary	$ 7.0				7						
School General Service - Demand	$ 0.3			12							
Transmission	Confidential								2		
State General Service - Non Demand	$ 0.4		161	35						3	
State General Service - Demand	$ 23.0			78	166	1					
State Large Primary Service	$ 6.9					2	1				
State Large Primary Service Time-of-Use	Confidential						2				
State Primary Service	$ 1.5					6					
Ind. School Districts TOU	$ 19.6			61	193						
Large Industrial Rate, Primary	Confidential						2				
Large Industrial Rate, Secondary	$ 9.1				18						
Large Industrial Rate TOU, Primary	Confidential					2	6	2			
Large Industrial Rate TOU, Secondary	Confidential				2						
Large Industrial Rate TOU, Transmission	Confidential								1		
Large Primary Service Spec. Contract Rider	$ -										
Large Primary Service Spec. Contract Rider Secondary	Confidential				1						
Large Primary Service Spec. Contract Rider TOU	$ 20.6					3	9				
Large Primary Service Spec. Contract Rider TOU Secondary	$ 13.7				30						
Transmission	$ (0.0)								-		
Standby	$ 1.1										6
Security Lighting / Outdoor Lighting	$ 2.1									-	

Conclusions

In summary, the proposed customer classes are designed to be as simple and understandable as possible consistent with cost of service and unbundling objectives, so that customers can readily match their service requirements and usage characteristics to the appropriate class description and supporting rate structures. The proposed customer classes reasonably aggregate AE's customers into distinct groupings that reflect the utility's service requirements to successfully meet customer needs. Austin Energy believes that this proposal aligns with industry best practices for the following reasons:

1. Proposed customer classes reflect significant differences in the cost to serve; and
2. Proposed customer classes are designed to equitably aggregate customers with similar cost characteristics.

Section 3
REVENUE REQUIREMENT

The first step in the rate review process was the determination of the total utility revenue requirement for Test Year 2009 to represent the utility's normalized expenses and investment required to provide reliable electric services to customers and fulfill the utility's strategic objectives. To ensure that rates adequately recover costs, the revenue requirement represents historical expenditures, capital improvement requirements, and customer loads adjusted for current known and quantifiable changes. An historical fiscal year (FY 2009) was chosen and then adjusted based on "known and measurable" criteria to reflect typical or expected future financial and operating conditions of the utility. This adjustment resulted in a "Test Year" that represents the total costs to operate AE during a typical year. The total AE revenue requirement for TY 2009 is $1.136 billion. This section of the report describes the calculation of the utility's revenue requirement in detail.

After determining the utility's revenue requirement, a cost of service analysis was performed to determine how much it costs the utility to provide electric services to different customer classes. This process distributed the utility's revenue requirement by applying methodologies for allocating costs commonly used throughout the industry. The cost of service analysis helped the utility determine what charges and prices, or rates, to apply to each customer class or rate class. The next section of this report describes the cost of service analytical process and provides the cost of service results for this study.

Test Year Concept

The revenue requirement calculation is based on historical audited financial records with certain adjustments. Adjustments are made to historical records to reflect normal conditions and any change in expenses or operations that will be incurred by the time new rates are implemented. For an adjustment to be made to the historical financial records, the adjustment must meet the "known and measurable" test; first, the adjustment must be quantifiable within reason, and second, the adjustment must be "in use" or take effect prior to the effective date of the supporting rate structure.

Known and measurable adjustments may include the weather normalization of loads and associated revenues and expenditures, annualization of certain costs only included partially in the historical year, inclusion of new costs reflective of current operations, adjustments of historical costs that have changed significantly and removal of costs no longer relevant or useful to customers. It is common practice in the industry for municipal utilities to rely on approved budgets for certain adjustments. These adjustments, when applied to the historical FY audited financial statements, result in a "Test Year revenue requirement" to be used in the cost of service analysis and rate setting process.

FY 2009 Audited Financial Statements

Austin Energy used FY 2009 (October 2008 through September 2009) financial records for this rate review process, as these were the most recent audited financial records available at the time the study began. The benefit of using audited financial records is that this reflects the independent review and scrutiny of an accounting firm. Fiscal Year 2009 audited financial statements were then adjusted based on "known and measureable" criteria resulting in the TY 2009 revenue requirement. The audited financial statement results as well as the adjusted TY results are provided later in this section in Table 3.2.

Consistency with City of Austin Financial Policies

The TY 2009 revenue requirement was developed to be consistent with AE's financial policies, business goals, and objectives. With respect to financial policies, the City of Austin has adopted requirements related to capital structure, funding sources, debt and debt service coverage, general fund transfer, and reserves to which AE must conform. Abridged AE financial policies are included in Appendix B. Key financial policies taken into consideration in the development of the utility's revenue requirement are described below:

Debt Service Coverage:

- Austin Energy must maintain a minimum of 2.0 times ("x") debt service coverage for its existing Electric Utility Bonds. All short-term debt, including commercial paper, and non-revenue obligations must be maintained at 1.0x. Debt service coverage is the amount of cash flow available to meet annual interest and principal payments on debt. Debt is primarily incurred by the utility to fund capital projects, such as the construction of new power generation plants, transmission or distribution construction, metering projects, etc.

Reserves:

- Austin Energy may be required to maintain an additional debt service reserve fund if net system revenues are less than 1.5 annual debt service requirements.
- Austin Energy must maintain a Working Capital Reserve Fund. The Working Capital Reserve Fund serves to provide funds to meet normal day- to-day operation and maintenance expenses of the system.
  - The Working Capital Reserve Fund is funded at 45 days of system operation and maintenance expense excluding power costs.
- Austin Energy must maintain a Repair and Replacement Reserve Fund. The Repair and Replacement Fund shall be used for providing extensions, additions, and improvements to the Electric System.
  - The Repair and Replacement Fund is funded at a level that is equal to one-half (½) of annual depreciation expense. One-half of depreciation expense is a reasonable approximation of system wide repair and replacement requirements funded from cash. Depreciation expense as included in the

revenue requirement and described in this section provides an important source of cash to fund Repair and Replacement Fund and other reserve requirements.

- Austin Energy must establish a Strategic Reserve Fund. The Strategic Reserve Fund serves to provide funds to offset revenue fluctuations in AE's General Fund, which may come about due to natural or economic disasters. The reserve fund must have the following three components:
  - An Emergency Reserve with a minimum of 60 days of operating cash.
  - A Contingency Reserve with a maximum of 60 days of operating cash.
  - A Rate Stabilization Fund with a minimum of 90 days of power costs.
- Austin Energy must also maintain Nuclear and Non-nuclear Decommissioning Reserve Funds.
  - A Nuclear Decommission Reserve Trust Fund is periodically evaluated by AE management and currently established at $168,034,000.
  - A Non-nuclear Decommission Reserve Fund is periodically evaluated by AE management and currently established at $67,169,946.

Reserve Requirement

Over the past several years, AE revenues generated from rates have not covered total system expenditures or revenue requirements. As a result, AE has been drawing down cash reserves to meet its financial obligations. Using cash reserves to cover expenditures is an unsustainable process that threatens the long-term financial strength of the utility. The TY 2009 revenue requirement indicates that AE is no longer meeting minimum reserve requirements as described above and reserves must be replenished. This is a strong indication that a rate increase is necessary.

As part of the FY 2012 budget process, AE has updated its reserve policies so that existing and newly defined reserves appropriately reflect the use of funds and ensure the continued financial strength of the utility. The TY 2009 revenue requirement includes line items that identify specific reserve funding levels and allow the utility to gradually re-build those reserves that are currently deficient. Changes to the existing reserve policy is as follows.

Rate Stabilization Fund

Austin Energy is proposing the establishment of the Rate Stabilization Fund. The Rate Stabilization Fund would replace The Competitive Reserve Fund. Funds in this reserve are to be used to stabilize electric utility rates in future periods. Annual transfers into and out of this fund 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 Fund may be used to absorb fluctuations in the net settlement costs associated with the ERCOT power market. To the extent that funds are available above minimum funding requirements, rate stabilization funds may be used to offset the cost of new power generation that would increase electric rates. Transfers from the Rate Stabilization Fund are authorized on an event driven basis with approval by the City Council via budget action. The administration of the Rate Stabilization Fund goes hand-in-hand with the proposed Energy Adjustment as described in Section 5.

Repair and Replacement Fund

Austin Energy is proposing establishing the funding of the existing Repair and Replacement Fund at one-half the dollar value of annual depreciation. This financial target is suggested with consideration to the capital funding assumptions included in the TY 2009 revenue requirement. The TY 2009 revenue requirement assumes that the Utility will fund capital projects equally from debt and current earnings. Setting the Repair and Replacement Fund at this level insures the AE will have adequate resources to properly recapitalize the system.

Cash Approach Methodology

Municipal utilities such as AE typically follow the “cash approach” methodology to determine their revenue requirement. Municipal utilities are not-for-profit and are primarily concerned with meeting their budget, contributing to their city’s general fund, and meeting their financial obligations such as debt service requirements. Therefore, in accordance with the cash approach methodology, the revenue requirement represents the gross annual cash required to operate, maintain, and capitalize the utility. The revenue requirement calculation for AE contains the following elements and is consistent with AE’s financial policies: (1) reasonable operating expenses; (2) debt service; (3) revenue to pay for capital projects; (4) annual deposits to replenish required reserves; (5) general fund contribution to the City of Austin; (6) recognition of other revenues to be earned such as new service connections; and (7) all other miscellaneous financial obligations related to the provision of electric service.

Austin Energy follows FERC guidelines for accounting of utility revenues, expenses, and the utility’s assets and liabilities. Revenues and expenses are grouped by FERC accounting numbers in AE’s revenue requirement calculation and its COS study results. Results of the revenue requirement calculation, including work papers for the known and measurable adjustments, and cost of service analysis results provided in the Appendices of this report include the FERC accounting numbers for all utility expenses. FERC accounting is required for all investor-owned utilities, but is not a regulatory requirement for most municipally-owned utilities. However, adhering to FERC accounting guidelines is an industry best practice that AE has chosen to follow. Key components of the cash approach revenue requirement calculation are described below. The audited financial statement results for FY 09 as well as the adjusted TY results for each of these categories of expenses is provided in Table 3.2 later in this section.

Operation and Maintenance Expenses

Operation and maintenance ("O&M") expenses include all costs to operate the utility and provide electric services to customers, including customer service, and all maintenance and repair of utility assets. Austin Energy incurs O&M expenses for each of its four primary utility functions (Production, Transmission, Distribution, and Customer Service) so that it can maintain an efficient and reliable system and provide excellent customer service. For AE, O&M expenses make up approximately two-thirds (67 percent) of the utility's total expenses, a typical result for a vertically-integrated utility like AE. FERC accounting methodology tracks O&M expenses under the following categories:

- **Power Production Expenses** – O&M expenses for power production including fuel, labor, routine maintenance, system control and dispatch of power plants, and purchased power expenses. Power production is the generation of electricity.
- **Transmission Expenses** – O&M expenses for transmission lines and transmission substations including labor and routine maintenance. Electric transmission reflects the infrastructure by which electricity produced at power plants is transported over long distances to customers. In ERCOT, the system in which AE operates, the transmission function is defined as facilities operating at a voltage of 60,000 volts or higher.
- **Distribution Expenses** – O&M expenses including labor and routine maintenance for overhead and underground distribution lines and circuitry, distribution substations, streetlights, service transformers, and meters. Electric distribution is the final stage in the delivery of electricity to customers and includes stepping down the service voltage to a level of usage that is safe for different customer types. On AE's system, distribution equipment is generally operated at 12,500 volts (12.5 kV) or less and includes the electrical equipment that directly serves customers.
- **Customer Expenses** – Customer-related O&M expenses including meter reading, billing, collections, sales, advertising, customer assistance, and other customer service and communication activities.
- **Administrative and General ("A&G") Expenses** – Operating expenses including salaries of general and administrative personnel, office supplies and expenses, insurance, outside services, injuries and damages, employee pensions and benefits, and other general expenses. Because AE is a department of the City of Austin, certain administration and general support functions are provided by the City. AE reimburses the City for these services.

Depreciation Expenses and Amortization of Contributions in Aid of Construction

The AE financial policy requires annual depreciation expenses for plant and facilities as well as amortization of Contributions in Aid of Construction ("CIAC") to be included in the revenue requirement calculation. Depreciation is an annual charge included in expenses to reflect the use of an asset or group of assets over their estimated life. As an example, an asset with an estimated life of 30 years may have one-thirtieth (1/30 or 3.33 percent) of its original cost as an annual depreciation expense to reflect the age and value of the asset.

Depreciation expense does not represent an actual cash expense, as the cash expenditure associated with the asset is incurred when the asset was built or installed. AE pays for utility plant with a combination of cash from reserves or with debt. Debt financed plant is included in the revenue requirement as debt service. Even though depreciation is a non-cash item, funding of depreciation expense creates cash for AE that is directed towards annual capital needs for improving the system. The primary advantage of including depreciation in the revenue requirement calculation is that cash generated through depreciation expense mirrors the capital costs associated with maintaining existing plant-in-service as it naturally wears out. Therefore, including depreciation in the revenue requirement creates a pool of cash that contributes to renewal and replacement of the existing system. Funding of depreciation expense through rates is an important source of cash for AE and is a key component in the margin calculation described later in this section.

Amortization of CIAC reflects contributed capital AE receives from customers associated with the cost of extending or connecting utility service to customers. AE amortizes these capital contributions over the life of the underlying asset. Similar to depreciation, amortization of CIAC is a non-cash item in the revenue requirement and is included in the margin calculation along with depreciation expense.

Capital Expenditures

Most electric utilities, including AE, are extremely capital intensive because a large amount of investment is needed to develop and maintain the electric utility system. Utilities must continually add new infrastructure and upgrade or replace existing infrastructure to maintain high system reliability. Austin Energy funds these capital projects through its capital improvement program with a combination of debt and current earnings generated from rates. Current earnings are the result of cash margins AE generates. One important contributor to these margins is depreciation expense as discussed above. Annually, AE finances about one-half (50 percent) of its capital expenditures from debt, and the other half from cash margins which falls within the requirements of AE’s financial policies.

Debt Financing and Debt Service

The portion of AE’s capital improvement program that is funded with debt is done so with a combination of short-term and long-term financing instruments. In the short term, AE utilizes a commercial paper program where funds can be borrowed as needed to pay for capital projects. The commercial paper program operates similarly to a letter of credit a homeowner may have with the bank. Typically, AE borrows short-term through the commercial paper program and builds a balance over a 12 to 18-month period. Typically, over this time AE will have borrowed approximately

$150 million in support of funding approximately one-half of its capital program. When short-term borrowing reaches this level, AE converts the commercial paper into long-term debt, typically in the form of electric utility revenue bonds. Long-term debt is similar to a homeowner's mortgage and requires AE to pay principal and interest on the debt over the term of the issue. The term of AE's long-term debt is generally 30 years because, per financial policy, AE cannot finance capital projects beyond their useful life.

Austin Energy's revenue requirement calculation includes annual debt service expense (principal and interest) associated with long-term debt plus interest expense related to short-term commercial paper borrowing. Per financial policy, AE must maintain a debt service coverage ratio of not less than 2.0 times on electric utility revenue bonds. A coverage ratio of 2.0 is in alignment with debt service coverage ratios of other public power utilities across the country. According to American Public Power Association 2009 data, municipal electric utilities that serve over 100,000 customers have a median debt service coverage ratio of 2.54 and a mean of 2.06. The debt service coverage ratio is the ratio of cash available for debt servicing to interest, principal, and lease payments. Adequate funding of AE's revenue requirement through rates must ensure that this policy is met. Meeting the proposed TY revenue requirement achieves a debt service coverage ratio of 2.37.

Capital Paid from Current Earnings

The remainder of the capital improvement program is paid with cash made available through rate revenues. Austin Energy maintains this cash in its Capital Improvement Program Fund and its Repair and Replacement Fund. In AE's revenue requirement calculation, capital improvement projects funded with cash are included in the margin calculation described below.

General Fund Transfer

The General Fund Transfer is included in AE's revenue requirement calculation. It is common practice for municipally-owned electric utilities such as AE to transfer a certain percentage of revenues to the city. Municipally-owned utilities provide general fund transfers in lieu of franchise fees, dividends, and return on investment similar to that of Investor Owned Utilities ("IOU"). As with IOUs, these costs are borne by all municipal utility customers. Unlike IOUs, these funds are invested back into the local community rather than to outside investors. This is a unique benefit of public power. Austin Energy provides its General Fund Transfer to the City of Austin on an annual basis in the amount of 9.1 percent of adjusted gross utility revenues averaged for the current budget year and the two most recent historical operating years.

Margin

Austin Energy's revenue requirement includes a margin. The margin reflects the remaining cash needs of AE after all other components of the revenue requirement have been considered. The margin calculation takes into consideration sources and uses of cash. Cash sources include depreciation expense (net of amortization of CIAC) as well as interest and dividend income. Cash uses include capital expenditures from current earnings and required contributions to reserves. For TY 2009, the required margin is $8,957,418 as shown in Table 3.3.

Other Expenses

Other expenses included in the revenue requirement are relatively minor. The most significant Other Expense item is associated with non-utility operations expense. This is related to AE's district cooling and heating business unit. All direct and indirect non-utility operations expense including the underlying investment has been removed from the revenue requirement.

Revenue Requirement Offsets

As described above, all of the components of the revenue requirement calculation capture the total annual revenue needs for the utility and the cost to serve customers. Included within these costs are investments and expenses incurred to provide services that will not be recovered through base rates, but rather through a compendium of miscellaneous service charges, monthly pass-through amounts, and charges to other third-party users of the system. Since the objective in assessing overall revenue requirement is to determine the total costs that must be recovered through base rates, revenue recovered through these additional methods must be computed as an offset to the amount needed to be recovered through base rates.

Other Revenue

Other sources of income that are not related to rate revenues must be netted against the total system revenue requirement. Other sources of income include fees and charges related to connection fees, equipment rentals, service charges, and maintenance agreements, among others. These income adjustments lower the overall revenue requirement.

Pass-Throughs

Pass-throughs are adjustments to base rates that can be made outside of a full rate review process to reflect changes in actual costs from year to year. An example of a common pass-through cost is a fuel charge that is typically billed to customers based on total monthly amount of electricity consumed. Fuel costs are reflected in a fuel adjustment clause due to the volatility of fuel prices and uncontrollable nature of fuel markets. In this rate review, AE is resetting its Energy Adjustment (previously called Fuel Adjustment Clause) to zero by including the current total cost of power in base rates. Other pass-through charges proposed for AE's new rates include a Regulatory Charge to recover regulated transmission costs and ERCOT fees and a Community Benefit Charge to recover costs associated with funding community street lighting across the entire AE service territory, a low-income discount program, and AE's energy efficiency initiatives. These pass-through charges will be discussed in Section 5 of this report.

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

Known and Measurable Adjustments

Austin Energy has made numerous known and measurable adjustments to the audited FY09 data which reflect normalized financial and operating conditions. Adjustments take into consideration costs and revenues that are the influenced by one-time events, abnormal weather or operating conditions, changes to costs since completion of the FY, or other events not reflected or improperly reflected in the historical year. Adjustments related to changes in cost structure, customers, or other factors are limited to items that are known, measurable, and in service by the time rates become effective. Table 3.1 lists the known and measurable adjustments made to FY09 financial statements by major category. Adjustments were made to both revenue and expense items totaling $30,372,435. Revenue and expense adjustments are shown in the table below with either positive (+) or negative (-) signs. Items with positive signs raise the revenue requirement. Items with negative signs lower the revenue requirement. A brief description of each adjustment follows the table. Supporting documentation for these adjustments is included in the cost of service model in the form of work papers. These work papers, contained in Appendix C of this report, include the calculations and assumptions used to determine the adjustments and references to source documents.

Table 3.1
Known and Measurable Adjustments by Major Revenue Requirement Category, TY 2009

		Revenue Requirement Category									
	Adjustment	**Total Operations & Maintenance Expenses**	**Depreciation & Amortization of CIAC**	**Debt Service**	**General Fund Transfer**	**Margin**	**Other Expenses**	**Other (Non-Rate) Revenue**	**Base Rate Revenue**	**FAC Revenue**	**Total Adjustment ($)**
1	Normalized Capital Improvement Program	-	-	-	-	-41,579,109	-	-	-	-	-41,579,109
2	Off-System Sales Revenue	-	-	-	-	-	-	+35,130,256	-	-	+35,130,256
3	Reserve Fund Contributions	-	-	-	-	+22,677,528	-	-	-	-	+22,677,528
4	Non-Electric Expense	-840,234	-3,619,223	-3,951,869	-	+3,619,223	-10,078,218	-	-	-	-14,870,321
5	Non-Electric Revenue	-	-	-	-	-	-	+13,799,872	-	-	+13,799,872
6	Transmission COS Offset	-	-	-	-	-	-	-10,066,863	-	-	-10,066,863
7	Interest & Dividend Income	-	-	-	-	+9,804,953	-	-	-	-	+9,804,953
8	Normalization of Load and Resources	-42,146,544	-	-	-	-	-	-	+34,304,635	+17,503,790	+9,661,881
9	Labor Costs	-8,552,604	-	-	-	-	-	-	-	-	-8,552,604
10	Transmission Expense	+7,437,633	-	-	-	-	-	-	-	-	+7,437,633
11	STP & FPP O&M	+4,746,478	-	-	-	-	+20,415	-	-	-	+4,766,893
12	Re-aggregated Customer Classes	-	-	-	-	-	-	-	-4,576,371	-	-4,576,371
13	FY 2011 Debt Service	-	-	-4,897,654	-	-	-	-	-	-	-4,897,654
14	Service Area Street Lighting Revenue	-	-	-	-	-	-	-	+5,821,743	-	+5,821,743
15	SHEC O&M	+4,147,447	-	-	-	-	-	-	-	-	+4,147,447
16	FPP Scrubber O&M Expense	+2,433,504	-	-	-	-	-	-	-	-	+2,433,504
17	Power Factor Revenue	-	-	-	-	-	-	-	-2,305,760		-2,305,760
18	Metering Expense	+2,047,526	-	-	-	-	-	-	-	-	+2,047,526
19	Remove Holly Write-off	-1,756,428	-	-	-	-	-	-	-	-	-1,756,428
20	STP Regulatory Asset Deferral	-1,748,752	-	-	-	-	-	-	-	-	-1,748,752
21	Rate Review Expenses	+1,292,907	-	-	-	-	-	-	-	-	+1,292,907
22	Franchise Fees	-	-	-	-	-	+1,123,778	-	-		+1,123,778
23	City Service	-4,488,138	-	-	+8,000,000	-	-3,871,685	-	-		-359,823
24	Uncollectible Accounts	+1,020,593	-	-	-	-	-	-	-	-	+1,020,593

Table 3.1
Known and Measurable Adjustments by Major Revenue Requirement Category, TY 2009

		Revenue Requirement Category									
	Adjustment	**Total Operations & Maintenance Expenses**	**Depreciation & Amortization of CIAC**	**Debt Service**	**General Fund Transfer**	**Margin**	**Other Expenses**	**Other (Non-Rate) Revenue**	**Base Rate Revenue**	**FAC Revenue**	**Total Adjustment ($)**
25	Update Other Revenue	-	-	-	-	-	-	+19,807	-	-	+19,807
26	New Building Lease	+517,778	-	-	-	-	-	-	-	-	+517,778
27	Legislative Advocacy	-314,242	-	-	-	-	-	-	-	-	-314,242
28	Removal of Holly Non-Labor O&M	-178,063	-	-	-	-	-	-	-	-	-178,063
29	Removal of Non-Electric Indirect	-	-	-	-	-	-125,676	-	-	-	-125,676
30	Overhead Redistribution	-125,676	-	-	-	-	+125,676	-	-	-	0
31	Net Additional Depreciation	-	+11,842,844	-	-	-11,842,844	-	-	-	-	0
	Category Total	**-36,506,815**	**+8,223,622**	**-8,849,523**	**+8,000,000**	**-17,320,250**	**-12,805,709**	**+38,883,072**	**+33,244,247**	**+17,503,790**	**+30,372,435**

Notes:

1. Excludes several adjustments that moved expenses between O&M FERC accounts, but did not increase or decrease the overall expense or revenue requirement.

1. **Normalized Capital Improvement Program** – Austin Energy makes annual investments, or improvements, in its system through its capital improvement program. The amount of investment in new capital projects varies annually depending on need and budget constraints for a particular year. Normalization of capital expenditures is a two part adjustment. First, the level of capital improvement program spending was normalized by taking an average of FY 2009 actual expenditures and projections for FY 2010 and FY 2011. Second, the financing of capital expenditures was adjusted assuming a 50/50 debt to current earnings capital structure. The combination of both adjustments resulted in a reduction in the total revenue requirement by $41,579,109.
2. **Off-System Sales Revenue** – Prior to implementation of the ERCOT nodal market in December 2010, AE earned revenue from selling power to the wholesale power market when it made economic sense to do so. These sales were specifically accounted for as off-system sales. Due to changes in the settlement process of the Texas wholesale power market implemented in December 2010, off-system sales accounting is no longer straightforward and the financial transactions surrounding off system sales are difficult to ascertain. Given this change in market structure, AE has included in the revenue requirement a normalized purchased power amount that reflects total purchased power costs net of market sales, or the ERCOT settlement balance. Therefore, off-system sales are included in the revenue requirement determination although not explicitly itemized. To prevent double counting of off-system sales, Other Revenue identified in FY09 as off-system sales were removed from the revenue requirement calculation. The new Energy Adjustment proposed by AE may include changes to the future ERCOT settlement balance for any future adjustments made.
3. **Reserve Fund Contributions** – Following the City of Austin's financial policies, AE annually sets aside certain amounts of money into specific reserve accounts, as described previously in this section. Test Year reserve levels associated with Working Capital, Strategic, and Repair and Replacement funding requirements are insufficient by $47,881,599 and do not meet AE financial policies. To replenish these reserves, the TY 2009 revenue requirement reserve margin includes $15,960,533 as shown in the Table 3.3 Margin Calculation. Additionally, TY 2009 reserve levels associated with the Non-Nuclear Decommissioning reserve are insufficient by $67,169,946 and do not meet AE financial policies. To replenish this reserve, the TY 2009 revenue requirement margin includes $6,716,995 as shown in the Table 3.3 Margin Calculation. In consideration of sources and uses of capital, as shown in the Table 3.3, the resulting margin line item included in the TY 2009 revenue requirement is $8,957,418.
4. **Non-Electric Expense** – This adjustment removes non-electric expenses from AE's revenue requirement as these expenses are generally recovered through direct billing to the customers who incur those expenses. Expenses classified as "non-electric" that AE incurred in FY09 included expenses for heating and cooling systems utilizing centralized systems (e.g., chilled water systems),

district energy systems, and other associated expenses. Removal of these expenses resulted in a reduction in the total revenue requirement in an amount equal to $14,870,321. This adjustment impacts power production, distribution, customer service, and administration and general operation and maintenance expense categories.

5. **Non-Electric Revenue** – The revenue requirement was adjusted to remove non-electric revenues consistent with the removal of non-electric expense as described above.

6. T**ransmission Cost of Service ("TCOS") Offset** – The TY 2009 revenue requirement assumes that the total cost associated with AE's regulated transmission function will be fully reimbursed by ERCOT participants through AE's approved wholesale transmission rate. Therefore, TCOS revenues were increased to equal the cost of the regulated transmission function as reflected in the cost of service analyses. The study assumes that AE will be regularly truing up the cost of the regulated transmission function through established TCOS proceedings at the PUCT. Note: the regulated transmission function excludes transmission of electricity by others (as identified in FERC code 565), which is recovered in AE's retail rates.

7. **Interest and Dividend Income** – This adjustment accounts for the decreased amount of interest and dividend income expected to be available as a funding source within the margin calculation. Interest and dividend income is associated with cash reserves and investments held by AE. Austin Energy investments are managed by the City of Austin Treasury Office. This adjustment resulted in a reduction in the total interest and dividend income available as a source of funds in the margin calculation by $9,804,953.

8. **Normalization of Load and Resources** – Weather conditions, unexpected power plant outages, and other abnormalities in any given year can skew customer load and resources used to serve that load for that year. In order to accurately reflect a typical year, a utility normalizes its load and resources for weather, customer growth within the TY, and typical operating conditions. Additionally, if new resources have come on-line since the selected TY or are expected to come on-line by the time new rates are implemented, those resources should be reflected in the utility's expected production costs.

   A normalization adjustment was made to reflect a normal weather conditions and customer growth during the TY. Austin Energy's system energy sales for FY 2009 were higher than expected due to high ambient temperatures which caused the system to experience its peak demand in June of 2009. Under normal conditions the AE system peak occurs in the month of August.

   This adjustment also accounts for the projected impacts on the operational dispatch of AE's power production resources and associated costs due to the addition to date of new resources or new resources expected to begin operation prior to new rates being implemented. This adjustment is made based on a production cost run, or simulation, of how AE's updated resource portfolio will be dispatched in the wholesale market. The simulation model used by AE, a software program called UPLAN that simulates market conditions, also accounts for the new nodal market structure implemented in December 2010, which impacts the way in which the utility's resources are dispatched and the settlement of revenues generated AE's production resources and costs to serve AE's customer load. The production cost run simulates the dispatch of resources and projects fuel and purchase power costs incurred by the utility. Production resource adjustments made in the production cost run include the addition of two new 45 MW quick start gas-fired combustion turbines at the SHEC (which began operation in 2010); the addition of a 30 MW solar PV facility located in Webberville (expected to be on-line in December 2011); and the replacement of expired wind power contracts with new wind power contracts assumed to be executed and in operation prior to the time new rates are implemented. The production cost run also accounts for the reduction in operational efficiency at the Fayette Power Project Plant ("FPP") due to the implementation of scrubber technology, which since FY 2009 has reduced sulfur dioxide emissions by up to 95 percent.

As discussed above, ERCOT implemented a new nodal market structure in December 2010. As a market participant, the Nodal Implementation Surcharge Rate AE is required to pay increased from $0.169 per MWh in FY 09 to $0.375 per MWh, which resulted in an increase in this portion of the ERCOT Administration fee of $2,408,468. The two other components of the ERCOT Administration fee were also adjusted based on the generation load predicted in the UPLAN production cost run, resulting in an adjustment of $126,731. Thus, the total adjustment to the ERCOT Administration fee in the TY was an increase of $2,535,200. Overall, normalization of customer loads, adjustments to the AE generation resource mix and additional ERCOT market participant costs reduced power supply O&M costs by $42,146,544.

Normalization of system loads and the supporting generation portfolio also impacted base rate and fuel revenues reflecting lower sales volumes and fuel costs. Weather normalization lowered sales volumes resulting in less base rate revenues. Additionally, lower costs associated with wholesale power market transactions resulted in lower fuel adjustment factor revenues. As a result, base rate and fuel revenues were reduced by $51,808,425.

The FY 2009 customer count was normalized to reflect the year end customer count.

The net impact of both components of this adjustment resulted in an increase of TY 2009 revenue requirement by $9,661,881.

9. **Labor Costs** – Labor costs for AE were adjusted downward to reflect a lower full time equivalent employee count ("FTE") as approved in the FY 2011 AE budget. Also, the FY 2011 budget approved an overall increase in employee salaries of 2.5 percent. Finally, labor costs were adjusted to remove a one-time non-cash expenditure related to a change in the funding of AE's retirement program. These adjustments resulted in a reduction of the total revenue requirement by $8,552,604.

10. **Transmission Expense** – This adjustment reflects the transmission expense AE incurs as a participant of the ERCOT nodal power market. AE must pay a portion of ERCOT system-wide transmission costs based on its contribution to the ERCOT summer peak. Transmission costs were adjusted to reflect AE normalized system peaks (see adjustment 8) and the most current transmission system-wide cost data provided by the PUCT. This adjustment resulted in an increase in the total revenue requirement of $7,437,633

11. **South Texas Project (“STP”) and FPP O&M Expense** – Compared to FY 2009, STP O&M costs have increased significantly as a result of added oversight and regulatory compliance requirements at the power plant. This adjustment resulted in an increase of the total revenue requirement by $5,143,930 for STP. The cost of O&M at FPP is increasing as well. However, an increase in O&M at FPP was offset by an amortization of a one-time expense related to the power plant’s ash pond, which occurred in FY 2009. The net impact of these offsetting adjustments resulted in a decrease in FPP O&M of $377,037. The combined FPP and STP O&M adjustment in the TY was an increase of $4,766,893 over the FY 2009 Actual.

12. **Re-aggregated Customer Classes** – As described in Section 2, AE has simplified existing customer classes and aligned customers based on cost of service differentiators such as service voltage and size. As a result, some customers in existing classes are being reassigned to new customer classes. Rate revenues were calculated for reassigned customers under the applicable rates. This reassignment of customers increased current rate revenues by $4,576,371.

13. **Debt Service** – This adjustment reflects a decrease in debt service payments based on AE’s existing debt amortization, net of debt service associated with non-electric utility assets. This adjustment resulted in a reduction of the total revenue requirement by $4,897,654.

14. **Service Area Street Lighting Revenue** – In FY09, AE recorded base rate revenue and fuel cost recovery associated with street lighting services for the City of Austin and neighboring communities. Under the proposed Community Benefit Charge, as discussed in Section 5 of this report, all costs associated with street lighting services throughout the AE service territory will be passed through to all electric customers, rather than being billed directly to the communities served. Therefore, revenue from these sources, in the amount of $5,821,743, was removed from the revenue requirement.

15. **SHEC O&M** – The cost to AE for the maintenance contract at the SHEC gas-fired power plant was normalized to reflect the variability of maintenance expenses associated with the facility’s five-year maintenance cycle. An adjustment was made to FY 2009 actual O&M expenditures based on a five-year average of the maintenance expense, including the 2011 budget for this maintenance contract. The resulting adjustment increased the revenue requirement by $2,699,254. Further, the operation of the new gas combustion turbines at SHEC is expected to add $1,448,193 in fixed and non-fuel variable

O&M to the cost of operation. The resulting total impact on the revenue requirement was an increase of $4,147,447.

16. **FPP Scrubber O&M Expense** – In the spring of 2011, the FPP coal plant was retrofitted with pollution control equipment known as scrubber technology to meet environmental compliance standards. Scrubber technology impacts plant efficiency and increases O&M costs. Plant efficiency impacts were included in the normalized generation portfolio analysis as described in adjustment 8. This adjustment takes into consideration increased O&M, associated with the scrubbers. The scrubbers will increase the total revenue requirement by $2,433,504.
17. **Power Factor Revenue** – AE is proposing to implement a power factor charge that encourages customers to operate at power factor levels at or above 90 percent. The current power factor charge encourages customers to operate at power factor levels at or above 85 percent. The increase in the power factor threshold is expected to increase revenues by $2,305,760, which reduces the revenue requirement.
18. **Metering Expense** –Since 2009, AE has entered into multi-year contracts for software and data management services to support new advanced meters. The TY was adjusted to reflect the costs associated with these contracts. This adjustment resulted in an increase of the total revenue requirement by $2,047,526.
19. **Reversal of Holly Inventory Write Off** – In FY09, AE expensed remaining inventory associated with the retired Holly Power Plant. This was a one-time, non-recurring expense. Thus, the TY was adjusted to remove this one-time expense from the revenue requirement, which reduced the revenue requirement by $1,756,428. Note: additional adjustments for Holly labor and non-labor O&M are reflected in adjustments 9 and 28.
20. **STP Regulatory Asset Deferral** – As a partial owner of the STP nuclear plant, AE is required to make certain payments for the regulatory assets associated with the facility. This known and measurable change is the result of an audit adjustment for the facility and resulted in a reduction of the total revenue requirement by $1,748,752.
21. **Rate Review Expenses** – This adjustment is to recover the costs associated with the rate review process and reflects AE's current budget estimate amortized over three years. This adjustment resulted in an increase of the total revenue requirement by $1,292,907.
22. **Franchise Fees** – As AE serves several surrounding communities in the City of Austin area, it recently agreed to serve these customers under the terms of franchise agreements which include a payment of franchise fees for the right to serve these customers. This adjustment resulted in an increase of the total revenue requirement by $1,123,778.
23. **City Services** – The TY reflects three separate adjustments associated with the City of Austin. The first adjustment is the expected new contra-expense

stemming from the City of Austin's Solid Waste Department sharing in the cost of the 3-1-1 Call Center. The second adjustment is the expected transfer from other City of Austin departments to share in the capital cost of a new billing system. The third adjustment is the increase in certain program costs supporting the City of Austin as well as the General Fund Transfer. In total, the net adjustment resulted in a decrease of the total revenue requirement by $359,823.

24. **Uncollectible Accounts** – When AE is unable to collect for services provided to a customer, these costs are not recovered through the normal rate mechanisms and must be collected from other customers. This adjustment takes into consideration rate changes proposed within this report and the resulting impact on uncollectable accounts. As such, the total revenue requirement was increased by $1,020,593 to account for the projected increase in uncollectible accounts.

25. **Other Revenue -** The Solar Explorer program is to be discontinued and, thus, the revenue from this program will no longer continue. This adjustment increases the revenue requirement by $19,807.

26. **New Building Lease** - This adjustment recognizes the increase in the cost of a new building lease and increases the total revenue requirement by $517,778.

27. **Legislative Advocacy** – Austin Energy has reduced certain expenses associated with federal legislation advocacy. This adjustment resulted in a reduction of the total revenue requirement by $314,242.

28. **Removal of Holly Non-labor O&M** – In FY09, a residual amount of O&M associated with the retired Holy Power Station remained in O&M expense. This O&M was removed from the TY resulting in a reduction of the total revenue requirement by $178,063.

29. **Removal of Non-Electric Indirect -** Consistent with adjustments 4 and 5 as describe above, indirect costs associated with non-utility expenses were removed from the FY 2009 O&M expenses. This adjustment resulted in a reduction of the total revenue requirement by $125,676.

30. **Overhead Redistribution** - In FY 2009, indirect overhead costs associated with capitalized labor were removed from A&G expense account (FERC 920) and added back to the appropriate FERC accounts (417, 500, 935). This adjustment is required as the City of Austin does not use the FERC system of accounts. Therefore, the City's accounting system cannot properly assign indirect overheads associated with capitalized labor to the specific applicable FERC expense account. As a default, the City's accounting system assigns these costs to FERC 920. Therefore, indirect overhead costs attributed to capitalized labor are understated in FERC accounts related to generation, transmission and distribution, and overstated in FERC 920 - A&G. To correct this misalignment of costs, a manual entry was made to more reasonably reflect actual cost by FERC account.

31. **Net Additional Depreciation** - This adjustment adds additional depreciation expense to the revenue requirement based adjustments to the TY plant in service. Adjustments include the removal of plant retired since FY 2009, non-electric plant in service, out-of-service meters, and the Holly power plant. Adjustments include the addition of the new scrubbers at FPP, the new combustion turbines at SHEC, the advanced metering system and the new billing system. As mentioned earlier in this Section, depreciation expense is a non-cash expense. Inclusion of depreciation in the revenue requirement provides a source of cash to AE in the margin calculation. As depreciation expenses changes, so does the cash available to fund AE capital programs and reserve requirements as shown in Table 3.3. The level of depreciation expense directly influences the margin amount included in the revenue requirement.

Other Adjustments

In addition to the Known and Measurable adjustments described above, certain other adjustments were made that did not impact the TY 2009 revenue requirement. These adjustments are as follows:

Reclassification of Costs

a. Meter Reading: A certain amount of meter reading expense in the FY 2009 actual ($1,131,023) was moved from FERC account 586 (Meter Expenses) to 902 (Meter Reading Expenses) to correctly account for this expense and facilitate proper allocation.

b. Prepaid Insurance: A certain amount of prepaid insurance in the FY 2009 actual ($2,382,695) was moved from FERC account 925 (Injuries and Damages) to 924 (Property Insurance) to correctly account for this expense and facilitate proper allocation.

c. Production: The costs associated with certain programs (energy efficiency, green building, and solar rebates), which are accounted for within the Customer and Information Expenses FERC accounts, were moved to the Production function to allow these programs to be allocated as generation resources based on the way in which AE views these programs.

d. SHEC: Certain costs associated with the operation of SHEC were moved from the steam FERC accounts to the FERC accounts associated with other generation to correctly account for these expenses.

e. G&A: The costs associated with certain programs accounted for within the Customer and Information Expenses FERC accounts were moved to the G&A FERC accounts as these programs were determined to be better allocated with G&A expenses. These programs include expenses associated with ITT and Human Resources.

Test Year Revenue Requirement

As detailed in Table 3.2, the total TY Revenue Requirement is the sum of total O&M expenses, depreciation and amortization, debt service, general fund transfer, margin, other expenses less non-rate revenue. The margin is calculated by determining the difference between the cash sources (depreciation expense and investment income) and cash uses (capital improvements plus required contributions to reserves). Given this calculation, the TY Revenue Requirement is approximately $1.136 billion. Additional detail with respect to the calculation of the margin is shown in Table 3.3.

Table 3.2
Test Year 2009 Revenue Requirement

Item	FY09 ($)	Adjustments ($)	TY09 ($)
Operation & Maintenance Expenses			
Production ($)	547,333,150	(4,217,099)	543,116,051
Transmission ($)	66,913,260	10,906,062	77,819,322
Distribution ($)	39,157,987	9,884,532	49,042,519
Customer ($)	67,341,767	(21,685,757)	45,656,010
A&G ($)	135,795,362	(31,394,553)	104,400,808
Total Expenses ($)	856,541,526	(36,506,815)	820,034,711
Depreciation & Amortization of CIAC ($)	108,990,890	8,223,622	117,214,512
Debt Service ($)	176,919,813	(8,849,523)	168,070,290
General Fund Transfer ($)	95,000,000	8,000,000	103,000,000
Margin ($)	26,277,668	(17,320,250)	8,957,418
Other Expenses ($)	16,358,459	(12,805,709)	3,552,750
Other Non-Rate Revenue ($)	(123,691,950)	38,883,072	(84,808,878)
Total Revenue Requirement ($)	**1,156,396,406**	**(20,375,603)**	**1,136,020,803**
$/MWh	95.75	0.41	96.16
Test Year Rate Revenue ($)	1,054,881,935	(50,748,038)	1,004,133,897
Deficiency ($)	101,514,471	30,372,435	131,886,905
Deficiency (%)	9.6	3.5	13.1

Table 3.3
Margin Calculation

Item	FY09	Adjustments	Test Year 09
Cash Sources			
Depreciation Expense ($)	114,171,721	8,223,622	122,395,343
Amortization of CIAC ($)	(5,180,831)	0	(5,180,831)
Interest and Dividend Income ($)	17,401,562	(9,804,953)	7,596,609
Cash Sources Total ($)	**126,392,452**	**(1,581,332)**	**124,811,121**
Cash Uses			
Capital From Current Revenue ($)	152,670,120	(41,579,109)	111,091,011
Required Contributions to Decommissioning Reserves ($)	0	6,716,995	6,716,995
Required Contributions to Working Capital, Strategic and Renewal and Replacement Reserves ($)	0	15,960,533	15,960,533
Cash Uses Total ($)	**152,670,120**	**(18,901,581)**	**133,768,539**
Required Margin ($)	**26,277,668**	**(17,320,250)**	**8,957,418**

Table 3.4
Debt Service Coverage

Item	FY09	Adjustments	Test Year 09
Debt Service Coverage Ratio	1.73	0.64	2.37

The TY 2009 debt service coverage ratio is 2.37 assuming that rate revenues are raised at the level requested. TY 2009 revenues at current rate levels yield a debt service coverage ratio of 1.58.

Austin Energy Revenue Increase Needed

Test Year rate revenue was calculated based on AE's existing rate structure utilizing the same normalized customer sales used in the TY revenue requirement. Table 3.2 shows that $1.004 billion would be expected to be generated given AE's existing rates, resulting in a short fall of approximately $132 million dollars, or 13.1 percent, between the TY revenue and the TY revenue requirement of approximately $1.136 billion.

Conclusions

The results of the revenue requirement analysis indicate the following:

1) AE's current rates generate insufficient revenue to cover its costs of operation, maintenance, and other financial obligations.
2) The TY 2009 revenue requirement indicates that overall system rate revenue should be increased by 13.1%. At this level, revenues will be sufficient to meet operation and maintenance expenses, debt service and debt service coverage, planned capital improvement expenditures, city transfers and franchise fee obligations, and required contributions to reserves.
3) The TY revenue requirement reasonably reflects the utility's operating costs at the time proposed rates are expected to take effect in January 2012.

Section 4
COST OF SERVICE ANALYSIS

A cost of service study is an analysis of how much it costs to generate and deliver power and support the customer service needs for each customer class. As described in Section 3 of this report, customer classes exist because the cost to serve different types of customer varies. For instance, the cost to deliver electricity to a very large industrial customer is different than the cost to deliver electricity to a home. The industrial customer may receive power from a single large power line that extends directly from a substation, while homes receive their electricity through an extensive network of power lines which represent greater infrastructure costs to build and maintain.

Austin Energy completed an unbundled cost of service study, meaning that costs were first separated by their underlying business functions and then allocated to customer classes. This enabled AE to develop charges and rates based on the way in which the utility incurs those costs. This enhances AE's assurance that it will meet its revenue requirement even when promoting energy efficiency, conservation, and self-generation, which create uncertainties in the revenue stream. Unbundling rates also creates opportunities to explore new rate options for customers. The unbundled cost of service analytical process contains three distinct steps:

1. Cost Functionalization – The TY Revenue Requirement is assigned to the major utility functions and sub-functions to reflect the overall cost of providing services to customers.
2. Cost Classification – Once costs are functionalized, the underlying factors that drive these costs are identified. Most commonly, utility costs are associated with the number of customers served and their demand and energy requirements.
3. Cost Allocation – Classified costs are allocated to each customer class based on the class contribution to total system costs.

The fully allocated cost of service study shows how much a customer class is over- or under-paying for electric service. This analysis provides the basis for developing new rates.

This section of the report describes the steps in the cost of service process, compares various methodologies for allocating fixed production costs, provides recommendations for allocating costs to customers, and provides the results of AE's cost of service study based on the TY Revenue Requirement and recommended cost allocation methodologies. This cost of service analysis was prepared in accordance with generally accepted practices in the industry as described by the American Public Power Association ("APPA"), the National Association of Regulatory Utility Commissioners ("NARUC"), and the National Rural Electric Cooperative Association ("NRECA"). The results of the cost of service analysis are summarized in this section with more detailed information provided in Appendix D.

Step 1: Cost Functionalization

The first step in AE's unbundled cost of service analysis was functionalizing the revenue requirement into the various utility functions (production, transmission, distribution, and customer service), a process that effectively unbundles these costs, and then sub-functionalizing costs within each function. These functions represent the products and services provided by the utility. In theory, each utility function faces unique market environments, business risks, and objectives. Therefore, cost drivers are unique to each function and should be reflected in the design of rates. The distinctive characteristics of each of AE's functions are summarized in Table 4.1.

Table 4.1
Major Utility Functions of Austin Energy

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

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

Derived allocators are allocation factors that are based on the sum, average, or weighted effect of different underlying factors. Derived allocators can be complex and should reflect the logical answer to the following question, "what underlying activities drive the cost of this item?" For example, A&G expenses are associated with the management and operation of all utility functions and thus are incurred throughout the utility in each function. Many A&G activities are associated with the management of utility staff. Therefore, these expenses are typically allocated to each function based on labor cost, which can be measured by the "level of effort" by function. Measures of level of effort include "employee salaries" and "number of employees." The PUCT provides guidelines associated with the allocation of A&G costs in TCOS filing requirements. In general, derived allocators used in this study were developed in accordance with PUCT TCOS guidelines.

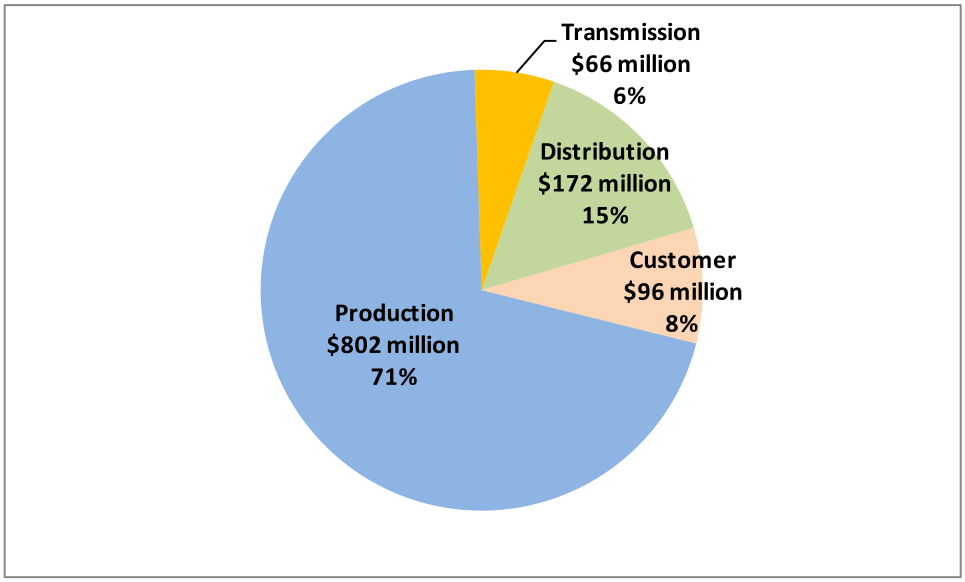
Using this approach, the TY Revenue Requirement was "unbundled" into the four functional areas. The results of this unbundling are summarized in Table 4.2 and illustrated in Figure 4.1.

Table 4.2
Unbundled Test Year Revenue Requirement

Function	Amount ($)	Average $/MWh Sold	% of Total
Production	801,730,829	67.86	70.6
Transmission(1)	65,915,251	5.58	5.8
Distribution	172,452,854	14.60	15.2
Customer Service	95,921,868	8.12	8.4
Total	**1,136,020,803**	**96.16**	**100.0**

Note:
1. Transmission of Electricity by Others (FERC 565) for retail rate recovery (i.e. excludes regulated transmission costs).

Figure 4.1
Test Year Revenue Requirement by Function



Production Function

Austin Energy generates about 12 billion kWh of power annually to meet the power supply needs of its customers by maintaining power generation resources including coal, natural gas, nuclear, wind, and landfill methane gas. Additionally, AE is bringing a solar PV facility online in December 2011. Maintaining a diverse resource portfolio is a risk management strategy as any resource can experience cost fluctuations in any year. Additionally, different resources are designed to supply power in different ways to meet the fluctuating demand of customers over the course of the day and seasons of the year. Costs associated with the production of electricity include fuel and purchased power expenses, certain O&M expenses, and expenses related to the financing and repair and replacement of AE's power generation resources.

Power generating resources are classified as either baseload, intermediate, or peaking to reflect how and when those units operate. Austin Energy's baseload power generation units, the most consistently used production resources, include AE's share of the FPP coal plant and STP nuclear plant. These resources cannot be quickly turned on or off and therefore tend to operate continuously. Baseload resources also tend to have high fixed costs that must be spread over many hours of operation to be cost-effective, and lower operating (primarily fuel) costs. Austin Energy's combined nuclear and coal generation provide almost 60 percent of the electricity produced by the utility's power production fleet.

Austin Energy's intermediate production resources, which help meet customer demand as it rises during the day, are the natural gas-fired steam turbines at Decker Creek Power Station and the natural gas-fired combined cycle units at SHEC. Intermediate resources tend to be fairly efficient resources and capable of tracking demand (easy to ramp up and down) over the course of the day.

In order to meet peak demand, the utility operates combustion gas turbine units at Decker and SHEC. These resources have the quickest response time and are able to be cycled on and off to meet fluctuations in demand. Peaking resources operate less frequently and thus are designed to have low capital costs, but also have comparatively high variable operating costs (again, primarily fuel-related).

Austin Energy also has power purchase agreements in place to meet about 10 percent of customer need through renewable wind energy. Additionally, AE generates a small portion of power from landfill gas and combined heat and power facilities. These resources tend to be classified as baseload because the terms of the contracts or the operational characteristics are such that they operate as available.

As described in earlier sections of this report, actual FY 2009 production costs were normalized to account for weather conditions, customer loads, the ERCOT nodal market, and changes to the generation portfolio. AE used the UPLAN power market simulation software to dispatch it units into the power market. In the nodal market, AE dispatches its generation resources to meet the ERCOT market load requirements. Simultaneously, AE purchases from the market the entire power requirements of the system. To the extent that the dispatch of generation assets into the market are greater than AE system load, then AE makes an off-system sales. To the extent that dispatch of AE assets into the market are less than AE system load, then AE makes market purchases. The net buying and selling of power into the market reflects AE power costs to customers. The nodal AE assets and related maximum capacity rating included in the simulation model are as follows:

- South Texas Project: Nuclear - 436 MW (Co-owner)
- Fayette Power Project: Coal - 597 MW (Co-owner)
- Sand Hill Energy Center: Natural gas, combined cycle - 598 MW
- Decker Creek Power Station: Natural gas, fuel oil as an alternative - 946 MW
- Methane from landfills: 10 MW
- Wind farms: 487 MW

- Solar: 29 MW

Sub-Functionalization

Production costs were sub-functionalized into baseload, intermediate, peaking, purchased power, and renewable categories to reflect the use of these power generation assets within AE's power generation resource portfolio. Generation assets were identified by fuel type, or in the case of renewables, the underlying technology. GreenChoice costs associated with wind power contracts were separately sub-functionalized as these costs are directly assigned to customers participating in the GreenChoice program. Additionally, administrative expenses associated with AE's participation in the ERCOT wholesale power market were sub-functionalized separately as these costs will be passed through to customers in a Regulatory Charge that will be described in Section 5 of this report.

In order to determine AE's power production costs categories, e.g., baseload, intermediate, peaking, renewables, purchase power, etc., AE's TY 2009 hourly normalized load are translated into a Load Duration Curve as shown in Table 4.2 AE's system load is shown in MW on the vertical axis and in hours that load was recorded or exceeded on the horizontal axis. Figure 4.2 also shows AE's power generation resources stacked on the load duration curve reflecting how these generating resources operate. AE's TY 2009 Load Duration Curve graphic indicates that the peak one-hour on the system is estimated at 2,493 MW (the far left of the figure). By contrast, the off-peak one-hour load on the system is never lower than the estimated 828 MW at any point in time during the TY.

Figure 4.2
Austin Energy's Generation Stack – TY 2009

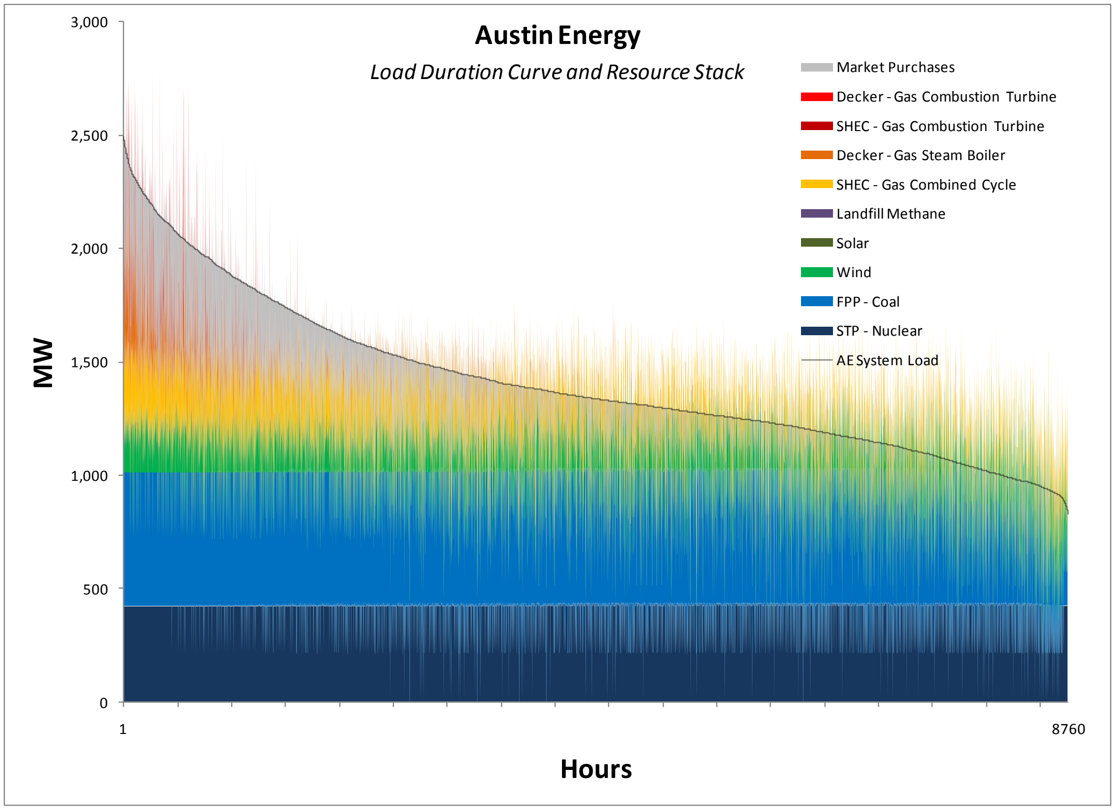


Figure 4.2 also details the specific power generation resources that are utilized to meet customer load during the year. The gaps between the load duration curve and the dispatch of AE resources reflect either market purchases or market sales. The thin line variations indicate short changes in dispatch due to issues such as the availability of renewable resources and unit outages (e.g., scheduled maintenance). The graph reflects STP and FPP are both baseload resources designed to operate continuously. SHEC combined-cycle gas units are intermediate resources used extensively during the year. The Decker steam unit is used intermittently throughout the year and extensively when system load exceeds 2,000 MWs. Decker and SHEC combustion gas turbines are peaking resources designed to operate during a limited number of hours per year. Finally, renewable wind and solar resources are also dispatched during baseload, intermediate, and peak periods (when available).

The production function was sub-functionalized into the following categories:

- Baseload – Nuclear
- Baseload – Coal
- Intermediate – Gas
- Peaking – Gas
- Renewable – Wind

- Renewable – Solar
- Renewable – Landfill Methane
- GreenChoice (Wind)
- Economy Purchased Power
- ERCOT Administration Fees
- Energy Efficiency

These sub-functions represent the different types resources that supply power to customers. The detailed results of the functionalization and sub-functionalization of production can be found in Appendix D. These results are summarized in Table 4.3.

Table 4.3
Production Function Test Year Revenue Requirement

Production Sub-Function	Test Year 2009 ($)
Baseload – Nuclear	197,083,491
Baseload – Coal	202,210,337
Intermediate – Gas	211,954,533
Peaking – Gas	24,499,242
Renewable – Wind	67,321,905
Renewable – Solar	20,900,538
Renewable - Landfill Methane	3,792,761
GreenChoice(1)	10,057,082
Economy Purchased Power	26,351,013
ERCOT Administration Fees	9,839,798
Energy Efficiency	27,720,129
Total	**801,730,829**

Note:
1. GreenChoice® reflects amount billed to customers subscribed to this program.

Transmission Function

Austin Energy delivers electricity to homes and businesses through a series of transmission and distribution lines that make up the electric grid. Austin Energy operates a portion of the statewide electric grid including its transmission lines and transmission substations and the local distribution system while ERCOT oversees the entire statewide electric grid. Austin Energy operates 634 miles of 345/138/69 kV (high voltage) transmission lines and 11 transmission substations. These power lines and substations deliver bulk power over long distances to the utility's distribution system. The transmission function includes all costs associated with operating and maintaining the transmission portion of the electric grid, including capital expenses.

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

Transmission Cost of Service

Costs associated with operating and maintaining AE’s transmission system are recovered through a TCOS process that is regulated by the PUCT. As a result, the cost of service associated with the transmission function is recovered through the ERCOT wholesale transmission tariff rate setting process and is not included in AE’s retail rate review. Austin Energy regularly files a TCOS study with the PUCT to update these costs. Once approved, AE’s transmission costs are pooled with all other transmission utilities in the ERCOT territory. These pooled costs are recovered from all participating utilities (including AE) based on each utility’s load-ratio share during four summer peak months (June-September) using the 4 CP cost allocation methodology. Austin Energy’s load-ratio share is calculated by dividing AE’s load on the system by the overall ERCOT system load. This allocation of ERCOT’s pooled transmission costs reflects AE’s share of ERCOT transmission costs and is included in the retail rate study as a revenue requirement line item and functionalized as a transmission expense. These costs are booked in FERC account 565 – Transmission by Others.

Sub-Functionalization

Because AE’s transmission cost recovery is regulated by the PUCT through a separate process, only the matrix charge booked as “Transmission by Others” is relevant for recovery within the retail rate structure. Therefore, sub-functionization is not required for transmission costs. The detailed results of the functionalization of transmission costs can be found in Appendix D. These results are summarized in Table 4.4.

Table 4.4
Transmission Function Test Year Revenue Requirement

Transmission by Sub-Function	Test Year 2009 ($)
Transmission by Others	65,915,251

Distribution Function

Distribution facilities connect customers with the transmission grid to deliver power that has been generated and transmitted to meet customer needs. Austin Energy connects the transmission grid and over 400,000 meters to the local distribution power grid with over 11,000 miles of distribution lines, 56 distribution substations, over 76,000 transformers, and approximately 145,000 poles. Delivery voltages range from primary voltage (12,500 volts) to secondary delivery voltages at 220/110 volts. The distribution function includes all costs associated with operating and maintaining the distribution portion of the electric grid, including capital expenses. This includes all of the equipment described above as well as primary and secondary conductors and meters and installations on customers’ premises.

Sub-Functionalization

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

- Primary – Substations, Poles, and Conductors
- Secondary – Poles and Conductors
- Transformers
- Services
- Load Dispatch
- Meters
- AE-Owned Lighting

These sub-functions represent a variety of utility products and services for which AE incurs costs in order to provide customers with adequate and reliable power at all times. The detailed results of the functionalization and sub-functionalization of distribution can be found in Appendix D. These results are summarized in Table 4.5.

Table 4.5
Distribution Function Test Year Revenue Requirement

Distribution Sub-Function	Test Year 2009 ($)
Primary – Substation, Poles & Conductors	88,666,341
Secondary – Poles & Conductors	37,442,772
Transformers	15,670,208
Services	(1,189,256)
Load Dispatch	4,919,046
Meters	17,108,086
AE-Owned Lighting	9,835,657
Total	**172,452,854**

In the above table, the sub-functionalization of distribution services is a negative number as non-rate revenues associated with service extensions (i.e., new service connections) exceed the cost of this sub-function, thereby resulting in a negative value.

Customer Service Function

The customer service function includes all aspects of operations to meet customer support needs. There are many separate business functions within AE’s customer service function. These functions include, but are not limited to, Billing Services, Customer Care, Customer Contact Center, Key Accounts, Operations Engineering, Revenue Measurement, Quality Management, and Customer Service Management.

Specific customer service support units include the Austin 3-1-1 call center, Information Technology, and Workforce Planning and Development.

Sub-Functionalization

Customer service costs were sub-functionalized into specific services provided to customers, with the cost of uncollectable accounts, or bad debt, sub-functionalized separately. Specifically, the customer service function was sub-functionalized as follows:

- Customer Accounting
- Customer Service
- Meter Reading
- Uncollectables
- Key Accounts

These sub-functions represent a variety of products and services for which AE incurs costs in order to provide customers with excellent customer service. The detailed results of the functionalization and sub-functionalization of customer service can be found in Appendix D. These results are summarized in Table 4.6.

Table 4.6
Customer Service Function Test Year Revenue Requirement

Customer Service Sub-Function	Test Year 2009 ($)
Customer Accounting	33,372,851
Customer Service	33,301,847
Meter Reading	20,913,388
Uncollectables	5,261,706
Key Accounts	3,072,075
Total	**95,921,868**

Step 2: Cost Classification

Once the cost functionalization step was completed, AE classified costs. Cost classification seeks to identify costs by their underlying nature, meaning drivers of cost such as electricity consumption, peak demand, and customer service needs. Typical cost classifications include demand-related costs that vary with customer peak usage or demand level (measured in kW), energy-related costs that vary with the amount of energy consumed by a customer (measured in kWh), customer-related costs (measured in number of customers), and revenue-related costs (measured by revenue requirement). Additionally, some costs can be directly assigned to a customer or customer class.

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

Demand-Related Costs

Demand-related costs are considered fixed costs as these costs do not vary with consumption. Demand-related costs are required to meet overall demand on the system (measured in kW) and are associated with the production, transmission and distribution systems. Austin Energy maintains an electric transmission and distribution system and portfolio of power generation resources designed to meet the highest point of demand at any point on the system. Thus, demand-related costs are assigned to each customer class based on the class contribution to system demand. For cost allocation purposes, class demands are determined at different points on the system. For the production and transmission functions, AE is concerned with meeting the system peak, therefore, class demands coincident with system peak are used to allocate cost to each rate class. The distribution function is concerned with meeting localized demands, therefore class maximum demands are often used to allocate distribution costs. Finally, near the customer meter, AE is concerned with the maximum demand that the customer places on the system. For commercial customers, this is typically billed demand, the overall system demand and each customer's contribution to system demand, referred to as the customer's CP demand. These demands are significant cost drivers for AE's capital expenses, including debt.

Energy-Related Costs

Energy-related costs are expenses that vary with electricity consumption (measured in kWh). The most significant energy-related cost incurred by AE is fuel. Fuel costs are directly related to the amount of electricity consumed by customers. The amount of coal, natural gas, and nuclear fuel expenses incurred by AE are all energy-related costs.

Customer-Related Costs

Customer-related costs are expenses that vary by the number of customers served and the unique customer service needs of different customer classes. For example, billing and meter reading are customer-related costs.

Revenue-Related Costs

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

Direct Assignments

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

Cost Classification Results

Cost classification results are provided in Appendix D. These results are summarized by category in Table 4.7. Production costs are classified as demand-related and energy-related. All transmission costs and most distribution costs are classified as demand-related. A small portion of distribution costs related to meters are classified as customer-related and an additional amount is directly assigned to applicable lighting customer classes. All customer service costs are classified as customer-related.

Table 4.7
Cost Classification of Test Year Revenue Requirement

Description	Demand	Energy	Customers	Direct Assignment[1]	Total
Production ($)	331,562,101	422,551,719	0	47,617,009	801,730,829
Transmission ($)	65,915,251	0	0	0	65,915,251
Distribution ($)	145,509,111	0	17,108,086	9,835,657	172,452,854
Customer Service ($)	0	0	95,921,868	0	95,921,868
Total Cost of Service ($)	**542,986,463**	**422,551,719**	**113,029,954**	**57,452,666**	**1,136,020,803**
Percentage of Total (%)	**47.8**	**37.2**	**9.9**	**5.1**	**100.0**

Note:
1. The Distribution direct assignment is related to AE-owned lighting

Step 3: Cost Allocation to Customer Classes

Cost allocation was the final step of AE's cost of service analysis. Allocation factors were developed and applied to appropriately distribute classified costs to each customer class based on the class' contribution to that cost. Each allocation factor was developed to be consistent with each cost classification methodology applied. For example, costs classified as energy-related were allocated to each customer class based on the electricity used by that customer class. Allocation factors were developed for demand-related, energy-related, and customer-related costs.

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

- Residential
- Secondary Voltage <10 kW
- Secondary Voltage 10 kW – <50 kW

- Secondary Voltage ≥50 kW
- Primary Voltage <3 MW
- Primary Voltage 3 MW – <20 MW
- Primary Voltage ≥20 MW
- Transmission Voltage
- Service Area Street Lighting[2]
- AE-Owned Private Outdoor Lighting[3]
- Non-Metered Lighting[4]
- Metered Lighting[5]

Demand-Related Cost Allocation Methods

The production, transmission, and distribution functions all have significant demand-related costs. The class allocation factors developed for these functions are discussed below.

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

Production Function

With regards to the allocation of production fixed or demand-related costs, a single preferred industry approach does not exist. Production demand allocation methods vary depending upon historical precedent and the utility's view of the underlying nature and causation of generation capacity. The Peak Demand Responsibility Method is based on the premise that production demand-related costs must be incurred by a utility to meet the system peak demand. Therefore, class contribution to the system peak demand causes the utility to build or buy sufficient generating capacity to meet the system peak. The Baseload, Intermediate and Peaking ("BIP") method considers that generation capacity serves different functions while meeting the system load. Baseload capacity is built primarily to produce low cost energy while peaking capacity is built to provide capacity at the lowest cost. A third method is the Average and Excess Demand ("AED") method. The AED method is based on the presumption that generation provides both demand and energy to customers; consequently, it allocates cost to customer classes based on class energy and peak demand

[2] Service Area Street Lighting is a community benefit cost that, after being determined, is allocated to all other customer classes in a later step in the cost of service process.
[3] E.g., security lighting.
[4] E.g., traffic lighting.
[5] E.g., sports lighting.

requirements. Unlike the other two methods, the AED method allocates demand-related costs to each customer class without regard to the peak demand responsibility. The method recognizes that capacity has value to customers at all times, not just at the time of the system peak. The cost of service results were evaluated under each of these three methods.

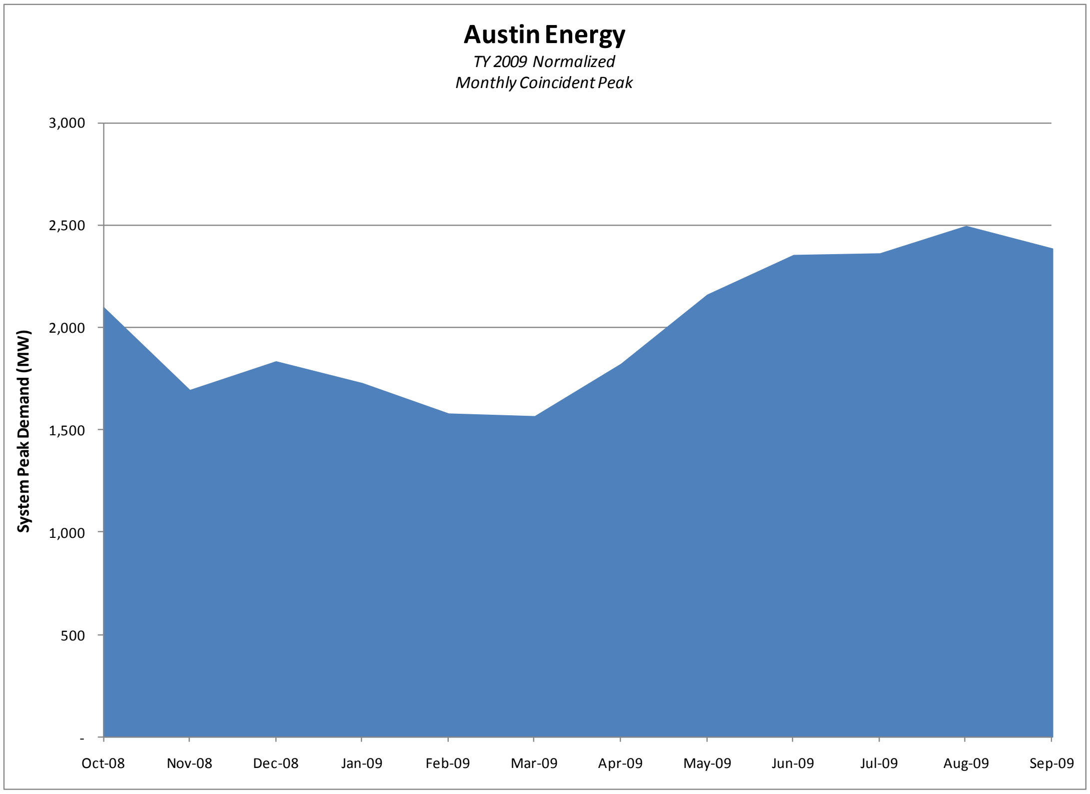
4 Coincident Peak Method (Peak Demand Responsibility Method)

Peak Demand Methods are among the simplest allocation methods in application as demand-related costs are allocated to each customer class based on each class's contribution to the system peak, known as CP. Coincident Peak methods can be calculated using one to 12 monthly peaks; ranging from a single month's CP ("1CP") to the average of the coincident peaks for 12 months of the year ("12CP"). The selection of the appropriate number of peak months to evaluate depends upon the unique circumstances and philosophy of the utility.

The advantage of the 1CP method is that it recognizes that a utility's capital investment costs are driven by power generation capacity needs at the system peak. The disadvantage of this method is that the resulting allocation of costs to each customer class can be highly variable depending upon the specific circumstances that created the system peak. Such variability can cause undue changes in cost of service results from year to year. To minimize variability exhibited by the 1CP method, it is common practice to consider the system peak over several months and allocate demand–related costs based on the average of the number of monthly peaks considered during the TY. Austin Energy has elected to allocate demand-related costs based on the class contribution to the system peak during the four months with the highest system peak, the 4CP method.

Figure 4.3 shows the monthly system peaks for AE during FY 2009. The figure shows that AE experiences a significant summer peak from June through September. Austin Energy's system is designed to have sufficient production capacity to meet demand during this summer peak period. As such, allocation of demand-related costs to each customer class is based on the four summer peak months or the 4CP method. Under this approach, the average of each customer class's contribution to the system peak, or coincident peak, for each of these four summer months was used to determine the cost allocation of demand-related costs. This information was also used to redefine AE's peak summer period as further discussed in Section 5 of this report.

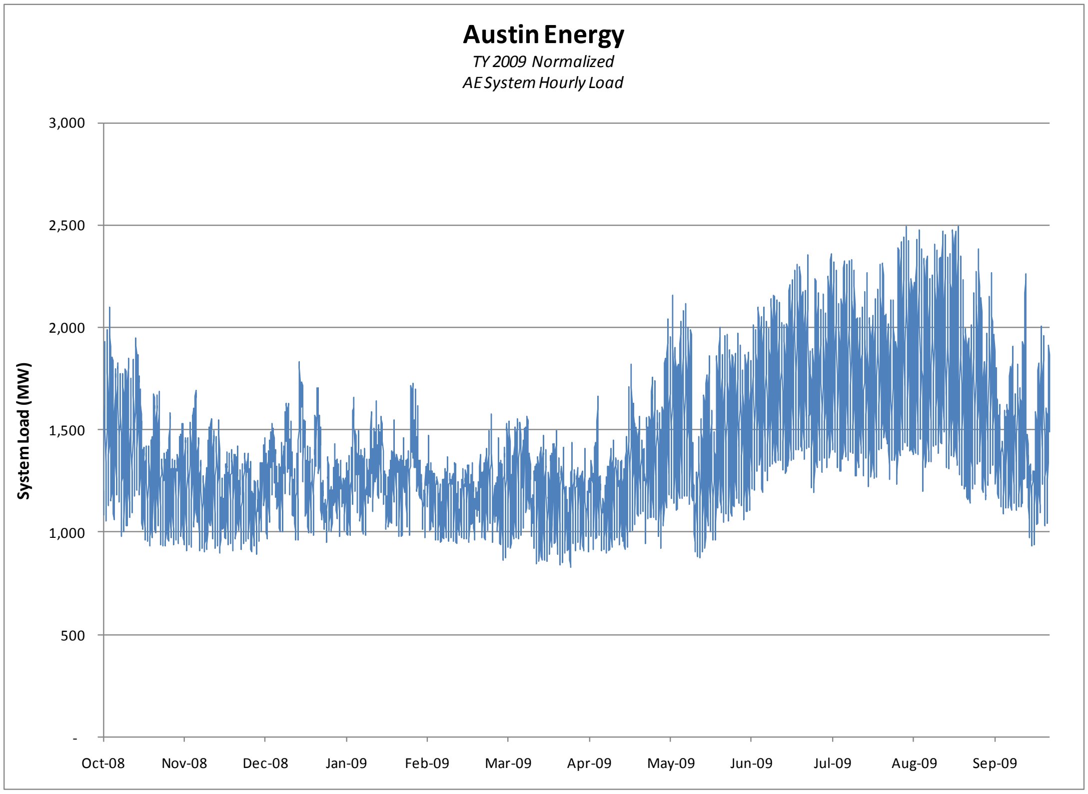
Figure 4.3
Austin Energy FY 2009 Normalized Monthly System Peak



Baseload, Intermediate, and Peaking Method (Time-Differentiated Method)

The BIP allocation method allocates demand-related production costs to customer classes based on each customer class's contribution to system load during assigned baseload, intermediate, and peak time periods. This method reflects the way in which AE incurs costs for producing electricity and how customer class characteristics including demand and overall energy use drive those costs. The need for this type of method is best illustrated by showing the variability in load experienced by AE. Figure 4.4 AE's TY 2009 Normalized Hourly load shows the extreme variation in load by day and season over the course of a year. Load fluctuates from minimum off-peak one hour load of 828 MW to a maximum peak one-hour load of roughly 2,500 MW. Although peak load occurrences above 2,000 MW occurs less than 10 percent of the time, AE must design a system that can handle the maximum peak load. This means that some of AE's system is in use for only a portion of time during the year to meet peak loads, creating economic inefficiencies.

Figure 4.4
Austin Energy Normalized Hourly Load (Test Year)



To meet fluctuations in customer load, different power production resources are dispatched. Production units are designed to be deployed at certain times to meet system needs. From a utility planning and operational perspective, power production resources (comprised of power plants and other power generation units or facilities such as wind farms) are grouped into three categories:

- **Baseload** – Baseload power generating units are large capital-intensive units that are designed and built to efficiently produce power. Because of their high efficiency and limitations for ramping up and down, these units run most of the time (typically 80 percent or more of all hours during the course of a year), except during repairs or scheduled maintenance. These units tend to have high fixed costs and relatively low variable costs (predominantly fuel). Coal power plants and nuclear power plants are the most common baseload plants. Austin Energy's FPP and STP facilities meet AE's baseload power needs.
- **Intermediate** – Intermediate power production units are designed to be flexible and efficient and meet demand during the times between baseload and system peak when demand varies substantially. These resources follow system load on a daily and seasonal basis and its usage and efficiency is between that of baseload and peaking plants. Intermediate resources can be easily ramped up or down depending upon the need. Intermediate units generally have lower fixed costs than baseload units but higher variable costs and typically run 40 to 60 percent of the time. Austin Energy's intermediate power generating units are

the natural gas-fired steam turbines at Decker and the natural gas-fired combined cycle units at Sand Hill.

- **Peaking** – Peaking production units are designed to meet the system peak and must have the capability to start quickly to meet system needs over short periods of time when system demand is the highest. These units typically have the lowest fixed costs but the highest variable costs. Typically, peaking units operate less than 20 percent of the time. Austin Energy's peaking power generating units are the natural gas-fired combustion turbines at Decker and Sand Hill.

Wind and solar resources are unique in that their availability depends on whether the wind is blowing or the sun is shining. These technologies can only generate electricity during certain periods of the day due to the variable nature of the energy source. As such, renewable resources cannot be dispatched or controlled to meet fluctuating demand. Renewable resources were placed into their own category in recognition of their intermittent dispatch capabilities.

Figure 4.5 depicts the AE system's TY2009 normalized load duration curve and resource stack reflecting how AE generation resources may be dispatched to serve load. In the nodal market, actual dispatch may vary depending up market conditions, but in general generation resources are available as shown in Figure 4.5. Renewable resources are grouped into the baseload category, and are dispatched when available.

Figure 4.5
Austin Energy Load Duration Curve and Resource Stack

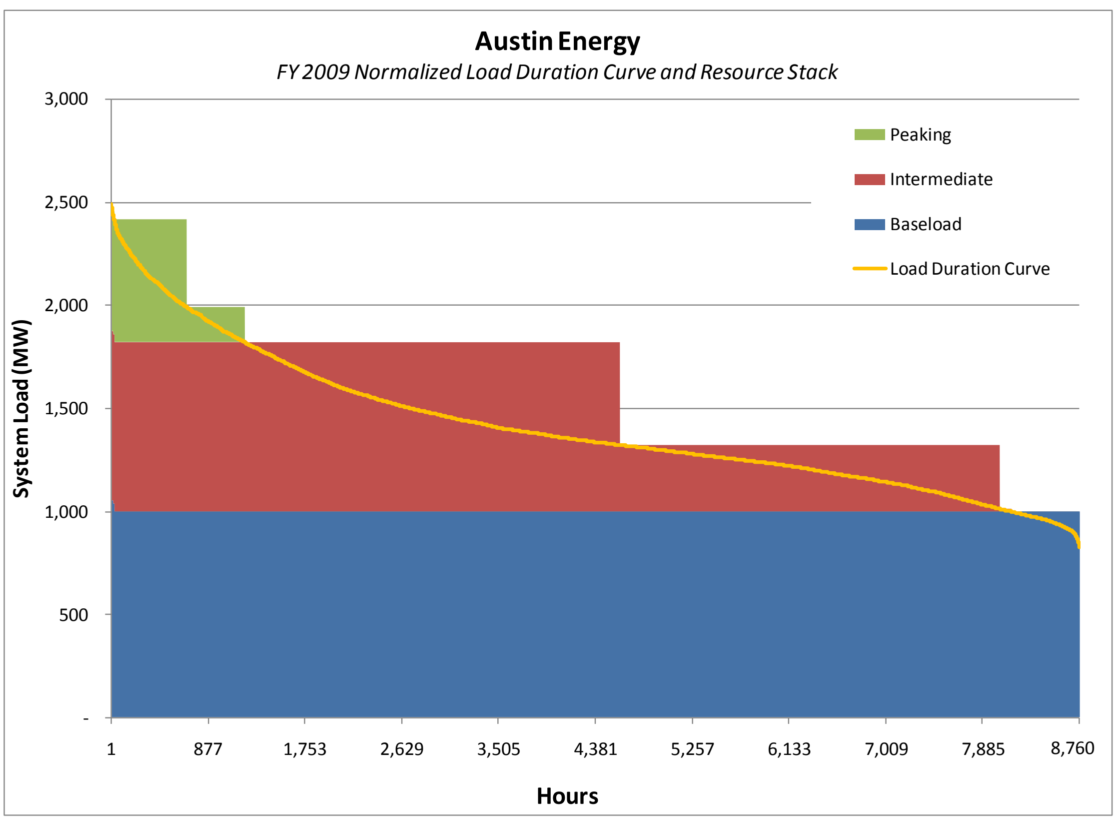


Figure 4.5 shows that the normalized TY peak load on AE's system was approximately 2,500 MW and was never lower than approximately 828 MW. It was above 970 MW over 98 percent of the time, which represents the system baseload power needs. However, from a planning perspective, AE must have sufficient power production capacity to serve its baseload, intermediate, and peaking needs (2,500 MW). Austin Energy meets its baseload requirement with a resource portfolio that includes about 1,000 MW of baseload generation capacity and 526 MW of renewable energy resources. AE meets its intermediate requirement with about 1,000 MW of intermediate capacity from the Sand Hill and Decker Power Stations. Additionally, at the Sand Hill and Decker Power Stations AE has almost 500 MW of peaking capacity.

In the ERCOT nodal market, AE no longer has a capacity and reserve requirement such that its capacity meets system load requirements. However, even in the nodal market, having enough generating capacity to meet load requirements is important as these assets act as a hedge against market prices. As shown in the figure above, AE's system peak occurs infrequently with system load exceeding 1,825 MW just 13 percent of the time. Intermediate load occurs over a significant number of hours during the year. In 2009, 67 percent of operating hours fell into the intermediate category. During these hours, intermediate resources (in addition to baseload resources) were utilized to meet AE's load.

The BIP method allocates production costs to each customer class from a planning perspective, considering the economic cost of each unit and how and when these resources are used. Power generation resources are ranked from lowest to highest based on an understanding of each units' marginal operating cost. AE's comprehensive power market simulation model (UPLAN) was the source for all unit specific marginal cost data used in this study. Generation resources with the lowest marginal costs are assigned to system baseload periods, resources with intermediate marginal costs are assigned to intermediate and peak periods, and resources with the highest marginal costs are assigned only to system peak periods.

Once assigned to their respective periods, fixed baseload production costs are allocated to meet system average demand. Since system average demand is equivalent to system energy, these costs are allocated to each customer class based on total electricity consumed (measured in kWh). Fixed intermediate production costs are allocated to each customer class based on the CP for each month of the year (12CP) since intermediate power generation resources are dispatched every month of the year to meet fluctuating loads. Fixed peaking production costs are allocated to each customer class based on the class contribution, or coincident peak, to each of the summer peak months of June, July, August, and September (4CP) since AE's peaking units are designed to operate only in times of peak demand.

Average and Excess Demand Method (Energy Weighting Method)

One of the most widely used weighting methods is the AED method. The AED method recognizes that the utility's power generation resource portfolio is designed to meet both demand and energy needs of its customers and that customers benefit from this design. Under this method, the electricity usage characteristics of each customer class are evaluated to determine class "average demand" and class "excess demand." Average demand (measured in kW) is a measure of the demand a class places on the system over the course of the year. Average demand is calculated by dividing annual customer class electricity usage (measured in kWh) by the typical number of hours in a year (8,760).

Excess demand measures the difference between the customer class's annual maximum demand and its annual average demand. Maximum demand is the measure of peak demand for a particular customer or group of customers. This peak can happen at any time of the year and may or may not be coincident with the system peak. For this reason, this measure is referred to as the non-coincident peak of the customer class.

Once excess demands for each customer class are calculated, the excess demands for each class are summed up and trued-up to match system excess demand. System average demand is simply annual energy divided by the hours in the year. System excess demand is the CP or (1CP) less average system demand. Once this adjustment is completed, average demand and excess demand are summed for each customer class. This summation results in the AED allocator for each class and reflects the relative mix of energy and demand as a cost driver for each class.

Comparison of Methods

The above three methodologies can be compared qualitatively and quantitatively. A qualitative comparison is provided in Table 4.8.

Table 4.8
Qualitative Comparison of Production Cost Allocation Methods

Item	BIP	AED	4 CP
Allocation Perspective	Supply side, system planning perspective. The BIP method focuses on the use and usefulness of generation resources. On-peak customers are allocated peak and intermediate production fixed costs. Classes that are off-peak are allocated little to no production peak and intermediate fixed costs. All customers are allocated production fixed costs associated with baseload units.	Efficiency perspective. The AED method considers the relationship between class energy and demand requirements. Production fixed costs are allocated to each class based on a mix of demand and energy in similar proportions as class load factor. More efficient, higher load factor classes are allocated a lesser proportion of production fixed costs associated with excess capacity compared to lower load factor classes. Additionally, the AED method assumes that all customers benefit from system capacity, regardless of a customer's peak, so all rate classes are allocated production fixed costs.	Demand-side perspective. The 4CP method assigns production fixed costs to each customer class in proportion to class contribution to system peak. Classes that are substantially off-peak are allocated little to no production fixed costs.

Table 4.8
Qualitative Comparison of Production Cost Allocation Methods

Item	BIP	AED	4 CP
Industry Acceptance	The BIP method itself is not widely used, but other similar methods are used more frequently (Probability of Dispatch and Equivalent Peaker Method). These methods allocate all or a large portion of fixed costs associated with baseload units to customer classes based on energy. These methods are more common in the western U.S.	One of the most common allocation methods used in the industry.	Variations of the CP methodology are commonly used in the industry.
Use in Texas	Limited use.	Modified AED method used by PUCT.	4 CP used by PUCT.
Applicability to Nodal Market	Highly applicable, reflects generation resources likely dispatch into the wholesale power market and recognizes the underlying value as a hedge.	Less applicable to the nodal market. Views generation portfolio as a homogeneous resource serving customer's demand and energy requirements	Less applicable to the Nodal Market. Views generation portfolio as a homogeneous resource serving customer's demand requirements
Alignment with AE core values	Shifts costs to high load factor/ high energy users. Customers that are substantially off-peak are allocated little to no production costs associated with peaking and intermediate generating units.	Shifts costs to customer classes that are inefficient in the sense that customers use relatively less energy in relationship to their maximum demand. All customer classes share in production fixed cost recovery regardless of the customer class' contribution to system peak.	Shifts costs to low load factor, highly coincident customers based on class contribution to system peak. Customers that are substantially off-peak are allocated little to no production costs.

Table 4.9 provides a quantitative comparison of these three cost allocation methods results using the three production function demand-related cost allocation methods described above plus the allocation of cost items related to regulatory and energy efficiency expenses.

Table 4.9
Production Function Demand-Related Cost Allocation
Comparison Based on Allocation Method

	Demand Related Costs ($)		
Customer Class	**AED**	**BIP**	**4 CP**
Residential	151,405,665	125,987,746	145,736,409
Secondary Voltage <10 kW	12,983,578	12,751,661	13,274,502
Secondary Voltage 10 - <50 kW	33,070,843	31,762,392	34,518,317
Secondary Voltage ≥50 kW	120,308,343	128,792,710	125,888,259
Primary Voltage <3 MW	9,738,995	11,875,837	10,043,885
Primary Voltage 3 - <20 MW	15,933,252	22,031,593	15,729,550
Primary Voltage ≥20 MW	18,734,492	27,527,858	18,914,134
Transmission Voltage	4,414,718	6,866,384	4,585,247
Service Area Street Lighting	1,368,421	996,293	267,258
AE-Owned Private Outdoor Lighting	616,526	358,323	90,388
Non-Metered Lighting	77,862	43,588	4,783
Metered Lighting	469,332	127,644	69,296
Total	**369,122,028**	**369,122,028**	**369,122,028**

These results demonstrate that the BIP method is most favorable to residential customers and small business, while the 4CP and AED methods provide the most favorable results for the larger commercial and industrial customers. The 4CP method is the most favorable method for the lighting customer classes.

Recommended Method For Allocating Fixed Production Costs

Giving consideration to the various methods examined, AE recommends that the AED method be adopted for cost allocation. AE bases this decision on the following factors:

- The AED method recognizes that customers benefit from both demand and energy produced from generation assets.
- The AED method considers the class peak (NCP) rather than the class contribution to the CP, therefore the method shifts cost between classes considering the relationship between class maximum demand requirements and class energy requirements. This relationship is similar to monthly load factor. As a result, the AED method shifts costs to customer classes with lower monthly load factors. Austin Energy wants to encourage customer classes to reduce demand. Additionally, AE believes it is appropriate to recognize that high load factor customer classes are using power efficiently resulting in a lower cost of service. A cost allocation methodology that incentives customers to lower demand usage and/or improve load factor aligns well with AE's energy efficiency objectives.

- The underlying AED methodology is widely used. Variations of this method are recognized and accepted by the PUCT.

Transmission Function - ERCOT 4CP (Required Method)

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

Table 4.10 summarizes the customer class cost allocations for the transmission function's demand-related costs. This allocation represents 100 percent of the costs in the transmission function, which are all associated with transmission of electricity by others.

Table 4.10
Transmission Function Demand-Related Cost Allocation

Customer Class	Demand-Related Costs ($)
Residential	24,909,876
Secondary Voltage <10 kW	2,376,967
Secondary Voltage 10 - <50 kW	6,488,552
Secondary Voltage ≥50 kW	23,271,767
Primary Voltage <3 MW	1,804,147
Primary Voltage 3 - <20 MW	2,864,866
Primary Voltage ≥20 MW	3,371,416
Transmission Voltage	814,868
Service Area Street Lighting	2,478
AE-Owned Private Outdoor Lighting	0
Non-Metered Lighting	169
Metered Lighting	10,147
Total	**65,915,251**

Distribution Function

As noted earlier, distribution systems distribute power to customers through a series of poles, wires, substations, conductors, and transformers, and are designed to meet maximum localized demands.

12 NCP Method

Distribution facilities, such as substations, that directly interconnect with the transmission system are designed to meet the aggregated customer loads in a specific geographic area. As the system is designed to meet localized demand, these costs are most appropriately allocated by analyzing each class' non-coincident peak, or NCP. The 12 NCP method takes the average of each class' NCP for all 12 months. This method represents the annual average class peak and was used to allocate costs associated with distribution load dispatch, distribution substations, poles, and conductors at both the primary and secondary voltage levels.

Sum of Maximum Demands

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

Table 4.11 summarizes the customer class cost allocations for the distribution function demand-related costs.

Table 4.11
Distribution Function Demand-Related Cost Allocation

Customer Class	Demand-Related Costs ($)
Residential	61,808,222
Secondary Voltage <10 kW	6,062,801
Secondary Voltage 10 - <50 kW	13,923,583
Secondary Voltage ≥50 kW	50,508,233
Primary Voltage <3 MW	2,535,450
Primary Voltage 3 - <20 MW	4,399,710
Primary Voltage ≥20 MW	5,189,845
Transmission Voltage	0
Service Area Street Lighting	613,560
AE-Owned Private Outdoor Lighting	237,348
Non-Metered Lighting	34,123
Metered Lighting	196,236
Total	**145,509,111**

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

Energy-Related Cost Allocation Methods

Energy allocation factors are only applied to the production function. Energy allocation methods are used to allocate energy-related costs such as fuel and variable O&M at power plants. Compared to other types of allocation factors, energy allocation factors are relatively straightforward. Electricity consumption (measured in kWh) by customer class is readily available and was used in the development of these allocation factors. At the system level, each customer class's metered energy sales, adjusted for the proper level of losses depending on service voltage, were utilized to derive an Net Energy For Load ("NEFL") energy allocation factor. Determination of line losses at different service voltage levels were determined by a line loss study completed for this rate review.

When transmitting and distributing electricity, a certain percentage of energy is lost in the process due to resistance. In general, losses are estimated by calculating the discrepancy between energy produced and energy sold to customers. On average, system losses tend to be around 5 to 7 percent. NEFL represents the amount of energy that needs to be produced at the power plants to service customers at the point of the meter. In order to accurately allocate NEFL to each customer class based on the portion of the delivery system utilized by each class, AE completed a line loss study at three voltage levels; transmission, primary, and secondary. The purpose of the line loss study was to determine the percentage losses that occur at each voltage level at which AE customers take service. Line losses by voltage level, as indicated by the line loss study, are as follows:

Table 4.12
Line Losses By Delivery Voltage Level

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

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

Table 4.13 summarizes the customer class cost allocations for the production function energy-related costs.

Table 4.13
Production Function Energy-Related Cost Allocation

Customer Class	Energy-Related Costs ($)
Residential	142,915,612
Secondary Voltage <10 kW	13,924,857
Secondary Voltage 10 - <50 kW	36,285,550
Secondary Voltage ≥50 kW	152,242,573
Primary Voltage <3 MW	14,526,059
Primary Voltage 3 - <20 MW	27,546,142
Primary Voltage ≥20 MW	34,619,006
Transmission Voltage	8,742,603
Service Area Street Lighting	1,162,309
AE-Owned Private Outdoor Lighting	422,508
Non-Metered Lighting	62,343
Metered Lighting	159,240
Total	**432,608,801**

Customer-Related Cost Allocation Methods

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

Distribution Function

Metering costs incurred by different customers are dependent on the type of meter installed and the data gathered from those meters for billing and other purposes. Metering requirements can vary by customer class with the most expensive meters generally being used by large commercial and industrial customers. In order to properly allocate meter costs to each customer class, a weighted customer meter factor was developed to account for cost differentials in metering equipment. Weighting factors by meter type are shown in Table 4.14.

Table 4.14
Meter Weighting Factors

Customer Class	Meter Weighting Factor
Residential	1.00
Secondary Voltage <10kW	2.9
Secondary Voltage 10- <50 kW	2.9
Secondary Voltage ≥50 kW	4.9
Primary Voltage < 3MW	25.4
Primary Voltage 3- <20 MW	25.4
Primary Voltage ≥20 MW	26.2
Transmission Voltage	322.0
Metered Lighting	1.00

Table 4.15 summarizes the customer class cost allocations for the distribution function customer-related costs.

Table 4.15
Distribution Function Customer-Related Cost Allocation

Customer Class	Customer-Related Costs ($)
Residential	12,294,881
Secondary Voltage <10 kW	3,122,725
Secondary Voltage 10 - <50 kW	1,010,968
Secondary Voltage ≥50 kW	526,713
Primary Voltage <3 MW	87,361
Primary Voltage 3 - <20 MW	17,130
Primary Voltage ≥20 MW	3,530
Transmission Voltage	43,450
Service Area Street Lighting	0
AE-Owned Private Outdoor Lighting	0
Non-Metered Lighting	0
Metered Lighting	1,329
Total	**17,108,086**

Customer Service Function

Customer service functions include customer accounting (billing and collections), customer service, meter reading, and key accounts. The cost of uncollectible accounts is also included in this function. Uncollectable accounts are the cost associated with unpaid bills. For key accounts and uncollectable accounts, AE developed customer allocation factors that reflect the varying levels of cost associated with each customer class. For example, the cost of key accounts varies by customer class as some customer classes require additional effort while other customer classes are rarely served by the key account staff. This varying level of effort is considered in developing customer weighting factors for these costs. Class weighting factors were determined through discussions with various AE supervisors responsible for these services.

Weighting factors by customer service function are shown in Table 4.16.

Table 4.16
Customer Service Function Weighting Factors

Customer Class	Key Accounts	Uncollectibles
Residential	1.00	45.76
Secondary Voltage <10 kW	19.00	3.90
Secondary Voltage 10 - <50 kW	29.00	1.00
Secondary Voltage ≥50 kW	90.00	n/a
Primary Voltage <3 MW	13.00	n/a
Primary Voltage 3 - <20 MW	29.00	n/a
Primary Voltage ≥20 MW	8.00	n/a
Transmission Voltage	3.00	n/a
Lighting Classes	n/a	n/a

Table 4.17 summarizes the cost allocation by class for the customer-related costs. Customer-related costs represent 100 percent of the customer service function costs.

Table 4.17
Customer Service Function Customer-Related
Cost Allocation (Test Year 2009)

Customer Class	Customer-Related Costs ($)
Residential	82,589,419
Secondary Voltage <10 kW	7,541,285
Secondary Voltage 10 - <50 kW	2,780,004
Secondary Voltage ≥50 kW	2,126,162
Primary Voltage <3 MW	229,781
Primary Voltage 3 - <20 MW	468,281
Primary Voltage ≥20 MW	128,857
Transmission Voltage	48,855
Service Area Street Lighting	650
AE-Owned Private Outdoor Lighting	0
Non-Metered Lighting	163
Metered Lighting	8,410
Total	**95,921,868**

Direct Assignments

Some costs can be directly assigned to a customer class. Costs associated with AE-owned lighting distribution assets were directly assigned to the appropriate lighting customer classes. Table 4.18 summarizes this direct assignment of lighting costs to the appropriate lighting customer classes.

Table 4.18
Distribution Function Direct Assignment of Lighting Costs (Test Year 2009)

Customer Class	Direct Assignments ($)
Residential	0
Secondary Voltage <10 kW	0
Secondary Voltage 10 - <50 kW	0
Secondary Voltage ≥50 kW	0
Primary Voltage <3 MW	0
Primary Voltage 3 - <20 MW	0
Primary Voltage ≥20 MW	0
Transmission Voltage	0
Service Area Street Lighting	7,287,020
AE-Owned Private Outdoor Lighting	2,548,637
Non-Metered Lighting	0
Metered Lighting	0
Total	**9,835,657**

Revenue-Related Cost Allocation Methods

The Community Benefit Charge includes the costs associated with Service Area Street Lighting (i.e., street lighting within the AE service territory); CAP program funding; and the energy efficiency, green building and solar rebate programs (collectively referred to as Energy Efficiency). The Service Area Street Lighting cost was allocated to each customer class based on each class's associated revenue requirement. Table 4.19 summarizes the allocation of these costs to each customer class.

Table 4.19
Service Area Street Lighting Allocation

Customer Class	Service Area Street Lighting ($)
Residential	4,411,919
Secondary Voltage <10 kW	426,544
Secondary Voltage 10 - <50 kW	867,318
Secondary Voltage ≥50 kW	3,235,158
Primary Voltage <3 MW	268,112
Primary Voltage 3 - <20 MW	474,908
Primary Voltage ≥20 MW	575,191
Transmission Voltage	130,381
Service Area Street Lighting	(10,434,438)
AE-Owned Private Outdoor Lighting	35,459
Non-Metered Lighting	1,619
Metered Lighting	7,831
Total	**0**

The funding for CAP is based on a set rate per kWh. The CAP program costs are to be recovered via AE rates and administered by AE's Customer Service staff. The costs associated with CAP are not included in this cost of service analysis, but are shown in Table 4.20. The costs associated with Energy Efficiency are included in the demand-related production function costs listed in Table 4.20.

Cost of Service Results by Customer Class

Detailed cost of service results using the AED allocation methodology for the production function are provided in Appendix D of this report. Table 4.20 summarizes the cost of service results by customer class. Results are shown for each cost classification category by applicable functions.

Table 4.20
Cost of Service Results by Customer Class for Test Year Revenue Requirement

Cost of Service Results Summary

	Demand-Related				Energy-Related	Customer Related			Direct Assignment (Lighting)	Service Area Street Lighting	Total Cost of Service (COS)	Customer Assistance Program (CAP) 0.065 c/kWh	Total COS + CAP Adder	Application of CAP Funds	Total COS with Application of CAP Funds
Customer or Rate Class	Production ($)(1)	Transmission ($)	Distribution ($)	Subtotal ($)	Production ($)	Distribution ($)	Customer ($)	Subtotal ($)	Distribution ($)	($)	($)	($)	($)	($)	($)
Residential	151,405,665	24,909,876	61,808,222	238,123,763	142,915,612	12,294,881	82,589,419	94,884,301	0	4,411,919	480,335,595	2,511,861	**482,847,456**	(7,658,446)	**475,189,009**
Secondary Voltage <10 kW	12,983,578	2,376,967	6,062,801	21,423,346	13,924,857	3,122,725	7,541,285	10,664,010	0	426,544	46,438,756	246,275	**46,685,032**		**46,685,032**
Secondary Voltage 10 - <50 kW	33,070,843	6,488,552	13,923,583	53,482,978	36,285,550	1,010,968	2,780,004	3,790,972	0	867,318	94,426,817	641,574	**95,068,391**		**95,068,391**
Secondary Voltage ≥50 kW	120,308,343	23,271,767	50,508,233	194,088,343	152,242,573	526,713	2,126,162	2,652,875	0	3,235,158	352,218,949	2,692,696	**354,911,645**		**354,911,645**
Primary Voltage <3 MW	9,738,995	1,804,147	2,535,450	14,078,593	14,526,059	87,361	229,781	317,142	0	268,112	29,189,906	263,866	**29,453,772**		**29,453,772**
Primary Voltage 3 - <20 MW	15,933,252	2,864,866	4,399,710	23,197,827	27,546,142	17,130	468,281	485,411	0	474,908	51,704,287	500,389	**52,204,677**		**52,204,677**
Primary Voltage ≥20 MW	18,734,492	3,371,416	5,189,845	27,295,753	34,619,006	3,530	128,857	132,387	0	575,191	62,622,337	629,372	**63,251,709**		**63,251,709**
Transmission Voltage	4,414,718	814,868	0	5,229,586	8,742,603	43,450	48,855	92,305	0	130,381	14,194,875	160,953	**14,355,827**		**14,355,827**
Service Area Street Lighting	1,368,421	2,478	613,560	1,984,459	1,162,309	0	650	650	7,287,020	(10,434,438)	0	20,614	**0**		**0**
AE-Owned Private Outdoor Lighting	616,526	0	237,348	853,874	422,508	0	0	0	2,548,637	35,459	3,860,477	7,517 -	**3,867,994**		**3,867,994**
Non-Metered Lighting	77,862	169	34,123	112,154	62,343	0	163	163	0	1,619	176,279	1,109	**177,388**		**177,388**
Metered Lighting	469,332	10,147	196,236	675,716	159,240	1,329	8,410	9,739	0	7,831	852,526	2,834	**855,360**		**855,360**
Total	**369,122,028**	**65,915,251**	**145,509,111**	**580,546,391**	**432,608,801**	**17,108,086**	**95,921,868**	**113,029,954**	**9,835,657**	**0**	**1,136,020,803**	**7,658,446**	**1,143,679,249**	**(7,658,446)**	**1,136,020,803**

Notes:
1. Reflects the AED method for allocating production costs.

Table 4.21 shows the total cost of service results by customer class compared to estimated revenues based on AE's existing rate structures. The difference in these amounts indicates the shortfall in revenue needed from each customer class. Overall, the indicated shortfall, consistent with the shortfall of the TY revenue requirement shown in Section 2 of report, is 13.1 percent of revenue needs, or slightly more than $131 million.

Over 80 percent of the revenue shortfall is attributed to the Residential customer class, which is under-recovering by approximately $107 million. Slightly over 7 percent of the shortfall is attributed to the Secondary Voltage <10 kW customer class which is under paying by approximately $10 million. With the exception of Primary Voltage <3 MW and Transmission Voltage, all other customer classes are also currently under-paying their cost of service, many by a substantial margin.

Table 4.21
Rate Increase Needed to Meet Cost of Service by Customer Class

Customer Class	Cost of Service (1) ($)	Projected Revenue Under Existing Rates (2) ($)	Revenue Deficiency ($)	Increase Needed to Meet Cost of Service (%)
Residential	480,335,595	373,304,903	107,030,692	28.7
Secondary Voltage <10 kW	46,438,756	36,421,201	10,017,555	27.5
Secondary Voltage 10 - <50 kW	94,426,817	91,141,558	3,285,259	3.6
Secondary Voltage ≥50 kW	352,218,949	349,970,012	2,248,936	0.6
Primary Voltage <3 MW	29,189,906	30,377,964	(1,188,058)	-3.9
Primary Voltage 3 - <20 MW	51,704,287	47,083,898	4,620,389	9.8
Primary Voltage ≥20 MW	62,622,337	57,555,036	5,067,301	8.8
Transmission Voltage	14,194,875	15,816,915	(1,622,040)	-10.3
Service Area Street Lighting	N/A	N/A	N/A	N/A
AE-Owned Private Outdoor Lighting	3,860,477	1,955,348	1,905,130	97.4
Non-Metered Lighting	176,279	131,138	45,141	34.4
Metered Lighting	852,526	375,924	476,601	126.8
Total	**1,136,020,803**	**1,004,133,897**	**131,886,905**	**13.1**

Notes:
1. Reflects the AED method for allocating production costs and excludes CAP funding.
2. Adjusted for Test Year 2009 fuel.

Table 4.22 provides results on a unit cost basis, which are used in rate design. A pure cost based rate would reflect the unit costs as shown for each customer class in the table below.

Table 4.22
Unit Cost of Service by Customer Class (Excluding Lighting)

Cost of Service[1][2]	Residential	Secondary Voltage <10 kW	Secondary Voltage 10 -<50 kW	Secondary Voltage ≥50 kW	Primary Voltage <3 MW	Primary Voltage 3 - <20 MW	Primary Voltage ≥20 MW	Trans-mission Voltage
Customer Charge								
$/month	21.69	27.77	30.49	68.79	259.10	2,022.55	2,758.06	1,923.02
Electricity Delivery								
$/month	14.13							
$/kW billed		5.25	4.64	4.87	2.71	3.68	3.63	N/A
Energy (¢/kWh)								
Summer	3.818	3.818	3.818	3.818	3.731	3.731	3.731	3.684
Non-Summer	3.573	3.573	3.573	3.573	3.492	3.492	3.492	3.447
Demand ($/kW billed)								
Summer	6.44	10.77	10.65	11.18	9.93	12.62	12.34	10.17
Non-Summer	5.79	9.60	9.60	10.04	8.94	11.29	11.02	9.09
Community Benefit (¢/kWh)								
Customer Assistance Program	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Service Area Street Lighting	0.114	0.113	0.088	0.078	0.066	0.062	0.059	0.053
Energy Efficiency Charge	0.301	0.296	0.231	0.206	0.174	0.162	0.156	0.139
Regulatory Charge								
¢/kWh	0.729							
$/kW billed		2.33	2.44	2.57	2.28	2.93	2.92	2.49

Note:
1. Summer rate period is June through September and non-summer rate period is October through May.
2. Includes the Customer Assistance Program funding.

Allocator Factor Summary

Allocation factors considered in AE's cost of service study are summarized in Table 4.23 for reference.

Table 4.23
Allocation Factors

Allocation Factors	Description
Demand-Related Costs	
Production Function	
4CP	The 4CP allocator represents each class' contribution to the system peak during the 4 peak months of the year (June–September).

Table 4.23
Allocation Factors

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

Conclusions

The cost to operate the utility is divided between four primary functions:

- 71 percent of the utility's costs relate to construction debt, operation, maintenance, and fuel requirements of AE power plants – called the production function;
- 6 percent of the utility's costs relate to AE's Transmission of Electricity by Others (FERC 565) and contribute to maintaining and operating the state-wide transmission system, which includes the high-voltage power lines that deliver bulk power into and throughout the AE service territory – known as the transmission function (note: in the retail rate analysis this cost excludes the transmission costs recovered via the regulated transmission cost filing);
- 15 percent of the utility's costs relate to maintaining the extensive system of smaller power lines, poles, and related equipment throughout neighborhoods that deliver power to homes and business – known as the distribution function; and
- 8 percent of the utility's costs relate to customer service expenses including managing call centers, account management, and billing and metering expenses – known as the customer service function.

Cost of service results indicate that the majority of the revenue shortfall, over 80 percent, is attributed to the Residential customer class. The Residential class is under-recovering by approximately $107 million, or generating almost 29 percent less revenue than the cost to serve this class. The Secondary Voltage <10 kW class is under-recovering by approximately 27 percent. These results provided a starting point for AE's rate design and were strongly considered in the rate proposal presented in the remaining sections of this report.

Section 5
RATE DESIGN ANALYSIS

After determining the utility's revenue requirement and completing the cost of service analysis, AE developed its rate proposal. This final step in the ratemaking process is called rate design. Rate design can generally be defined as a structure of rates and charges developed in order to collect a desired revenue amount. The overall objective is to design rates and charges that fully recover the utility's revenue requirement, fairly allocate costs to customer classes based on cost of service, and align with the utility's strategic objectives.

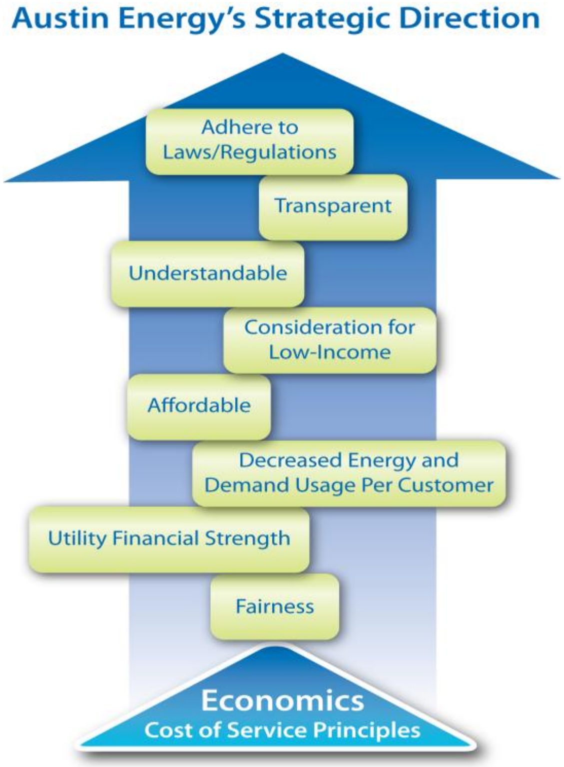
Austin Energy's Rate Design Principles

In designing rates, public power utilities like AE consider many factors including the results of a cost of service study and the economic health and priorities of the community. Rates may deviate from the cost of service results within each class, while remaining close to cost of service at the class level to meet various social and policy objectives of the utility and the community. For example, electric utilities such as AE have historically provided utility bill discounts to disadvantaged customers. Providing such a discount requires that the utility collect the discounted cost from other ratepayers. More specific to AE is its long-standing objective to promote energy conservation and energy efficiency investment throughout its service territory. This helps keep bills low and delays the need for additional infrastructure and power plants, reducing the need for future rate increases.

The utility's strategic objectives, reflected in AE's mission statement and Strategic Plan, serve as a guide for making business and policy decisions. It is critical that the utility's rate structures align with the utility's strategic objectives to ensure the continued financial strength of the utility and the successful implementation of the utility's goals and initiatives. For example, in order to achieve AE's goal of 800 MW of energy efficiency by 2020, AE's rate structures need to be designed to encourage customers to consume electricity efficiently. However, it is important that meeting this goal does not come at the detriment of the utility's financial health. Thus, rate structures must be established that ensure the utility meets its overall revenue requirement considering projections of reduced customer energy consumption.

Austin Energy's adopted rate design principles are illustrated in Figure 5.1 and listed below. The graphic indicates that rate design must be founded on a solid economic foundation such as cost of service, while balancing a variety of sometimes competing objectives, and ultimately aligning with the utility's strategic direction. All of AE's rate design principles are grounded in industry ratemaking best practices and are representative of local community values. These principles were also designed to be consistent with AE's rate review objectives discussed in Section 1 of this report.

Figure 5.1
Austin Energy's Rate Design Principles



1. Rates should be in alignment with AE's strategic objectives.

The rates designed 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. Austin Energy has taken the following actions in this rate review to meet this objective:

- Proposed rates that allow AE to successfully continue to deliver clean, affordable, reliable energy, and excellent customer service;
- Proposed rates that ensure the financial strength of the utility; and
- Proposed rates that promote the efficient use of resources and encourage energy conservation.

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 the utility's total revenue requirement, revenue stability, consideration of value of service, offering competitive prices, consideration of the impact of rate structures on consumer behavior, and a fair return to the utility's owners. 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. Austin Energy has taken the following actions in this rate review to meet this objective:

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

3. Rates should be fair among 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 has taken the following actions in this rate review to meet this objective:

- Prepared an unbundled cost of service analysis that identifies the key cost components necessary to serve each customer type;
- Gathered feedback from the community and identified community objectives and needs which may not be cost-based;
- Designed and proposed rates in alignment with cost of service results and in consideration of community objectives and needs; and
- Developed goals and metrics for evaluating the fairness of rates.

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 and the inability to meet its strategic objectives and goals. Austin Energy has taken the following actions in this rate review to meet this objective:

- Proposed rates at levels that fully recover the utility's revenue requirement to the extent possible;
- Proposed rates with pricing signals that support system efficiency and lower costs through the promotion of energy conservation and investment in energy efficiency improvements;
- Proposed rates that improve fixed cost recovery, reducing dependency on energy usage levels; and
- Proposed rates that pass potentially 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 as well as providing environmental benefits to the community. Rate structures can be developed that promote energy conservation and consumption patterns that support the efficient use of resources by sending pricing signals to customers, particularly those customers with high consumption and/or inefficient consumption patterns. Such rate structures empower customers to better manage their energy consumption and potentially lower their electric bills. Austin Energy has taken the following actions in this rate review to meet this objective:

- Proposed moving from a two-tiered to a five-tiered inclining block rate structure for residential customers that promotes energy conservation and investment in energy efficiency;
- Proposed applying a demand charge to all commercial and industrial customers as the appropriate pricing signal for encouraging conservation and promoting energy efficiency investment; and
- Developed long-term objectives to pilot new pricing models that empower customers to better manage their energy usage and provide improved pricing signals that conserve energy and encourage energy efficiency investment.

6. ***Rates should maintain the affordability of electricity.***

Austin Energy 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 financial realities and the need to meet AE's strategic objectives, affordability can best be achieved by designing rates that promote energy conservation and investing in energy efficiency improvements, while ensuring some rate relief for the most disadvantaged customers. Austin Energy has taken the following actions in this rate review to meet this objective:

- Committed to continue to aggressively control costs by evaluating the efficiency of AE's operations and keeping costs as low as possible;
- Committed to aggressively promote energy efficiency and conservation through existing programs and the new rate structures;
- Proposed rates that fairly distribute the needed rate adjustments and minimize rate impacts on low users;
- Proposed a funding mechanism to increase the amount of assistance provided to low-income and other disadvantaged customers; and
- Proposed rate alternatives that provide options for customers to manage their electricity usage and help keep their electric bills low.

7. Provide a discount to low-income customers.

Austin Energy recognizes its obligation to provide electric services 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 qualifying customers. Austin Energy has taken the following actions in this rate review to meet this objective:

- Created a pool of funds to support the Customer Assistance Program. Funds will be administered by AE's customer service function.
- Committed to improving the efficiency of homes of low-income customers and other disadvantaged customers; and
- Committed to continue providing 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, AE electric bills should be comparable with those of other electric utilities so that the utility and its customers can make comparisons. Austin Energy has taken the following actions in this rate review to meet this objective:

- Proposed rates that are designed to be practical, useful, and valuable with improved pricing transparency through unbundling;
- Proposed rates with consideration of public input, including feedback received from the Rate Review PIC; and
- Developed a public process to review AE's rate proposal.

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

Austin Energy has been committed to disclosing information relevant to the rate review process and soliciting feedback from the community throughout the rate review process. This objective of transparency helps ensure that rates are designed fairly and in accordance with the objectives and needs of the community. Austin Energy has taken the following actions in this rate review to meet this objective:

- Implemented a public involvement process during the rate review study period to solicit feedback on preliminary results and findings;
- Established a public involvement committee comprised of representatives of all customer groups to provide a forum for dialogue on rate issues and provide an opportunity for AE to receive feedback from each representative;
- Maintained openness and transparency during the process including the release of information on the rate review and preliminary study results to the public through a website dedicated to the rate review process and provided the opportunity for customer feedback through this website; and
- Established public processes before the Electric Utility Commission and the City Council to review the proposed rates.

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 is governed by the Austin City Council in the setting of rates and the Council must ultimately approve any changes to electric rates. Austin Energy has taken the following actions in this rate review to meet this objective:

- Established public processes before the Electric Utility Commission and the City Council to review the proposed rates;
- Determined the utility revenue requirement and designed and proposed rates that meet the financial policies of AE including all legal commitments and obligations to creditors and the City; and
- Followed the standards, guidelines, and requirements of the Federal Energy Regulatory Commission (“FERC”) for cost accounting.

Approach to Setting Fair and Reasonable Rates

The cost of service analysis provides a benchmark for determining the “fairness” and “reasonableness” of rates as it determines the costs incurred by the utility to support each customer class. As Table 5.1 shows, under existing rates, customer class revenues deviate from cost of service by varying amounts. It is not surprising or unexpected that variations from cost of service levels would occur among some AE customer classes because AE has not changed it overall rate design based on a cost of service study for over 17 years. If not periodically updated to reflect cost of service, rates become out-of-date due to changes in the underlying cost of service and strategic direction of the utility. Cost of service differences can be attributed to changes in AE's cost structure caused by the addition of a new power generation resource to the utility's resource portfolio, changes in customer usage characteristics, or the gain or loss of certain types of customers, among other reasons. Changes in the utility's strategic direction such as a stronger emphasis on energy conservation and energy efficiency or providing greater assistance to low-income and other disadvantaged customers, among other strategic objectives, can also affect the alignment of the utility's cost structures with the way the utility incurs costs.

Table 5.1
Rate Increase Needed to Meet Cost of Service by Customer Class

Customer Class	Cost of Service (1) ($)	Projected Revenue Under Existing Rates (2) ($)	Revenue Deficiency ($)	Increase Needed to Meet Cost of Service (%)
Residential	480,335,595	373,304,903	107,030,692	28.7
Secondary Voltage <10 kW	46,438,756	36,421,201	10,017,555	27.5
Secondary Voltage 10 - <50 kW	94,426,817	91,141,558	3,285,259	3.6
Secondary Voltage ≥50 kW	352,218,949	349,970,012	2,248,936	0.6
Primary Voltage <3 MW	29,189,906	30,377,964	(1,188,058)	-3.9
Primary Voltage 3 - <20 MW	51,704,287	47,083,898	4,620,389	9.8
Primary Voltage ≥20 MW	62,622,337	57,555,036	5,067,301	8.8
Transmission Voltage	14,194,875	15,816,915	(1,622,040)	-10.3
Service Area Street Lighting	N/A	N/A	N/A	N/A
AE-Owned Private Outdoor Lighting	3,860,477	1,955,348	1,905,130	97.4
Non-Metered Lighting	176,279	131,138	45,141	34.4
Metered Lighting	852,526	375,924	476,601	126.8
Total	**1,136,020,803**	**1,004,133,897**	**131,886,905**	**13.1**

Notes:
1. Reflects the AED method for allocating production costs and excludes CAP funding.
2. Adjusted for Test Year 2009 fuel.

While the utility needs to increase overall rates by 13.1 percent to meet its revenue requirement, the needed rate increase by class varies substantially with some customer classes currently paying more than their cost of service (Primary Voltage <3 MW and Transmission Voltage) and other classes (Residential and Secondary Voltage <10 kW) paying almost 30 percent less than their cost of service. This variation in the needed rate increase to meet cost of service is an indication that some customer classes are currently subsidizing other classes. If AE were to align each AE customer class with its cost of service this would have a disproportionate impact on customers, particularly residential customers, small commercial customers with demand less than 10 kW, and other commercial customers who do not currently have demand charges.

In order to minimize potential rate shock for customers, it is common for utilities to design rates that approach or move towards cost of service levels but do not align exactly with cost of service results. Given this consideration, AE is proposing rates that deviate slightly from cost of service for each customer class. To help determine an appropriate deviation from cost of service, AE developed a metric to measure the fairness and reasonableness of rates with a goal that no customer class pays greater than 105 percent of its cost of service or less than 95 percent of its cost of service, recognizing that overall rates must be set to meet the utility's revenue requirement. This goal is intended to minimize inter-class subsidization and move all customer classes towards cost of service levels. Table 5.2 shows the proposed revenue requirement for each customer class and includes a comparison of the cost of service results for each class with the proposed class revenue target. Overall rates are designed to meet the utility's revenue requirement and the proposed class revenue target for each customer class meet's AE's goal that no customer class pays greater than 105 percent of its cost of service or less than 95 percent of its cost of service.

Table 5.2
Cost of Service Compared to Class Revenue Target by Customer Class

Customer Class	Cost of Service (COS) (1) ($)	Proposed Class Revenue Target ($)	Difference ($)	Revenue Target as a Percent of COS (%)
Residential	480,335,595	456,325,851	24,009,744	95
Secondary Voltage <10 kW	46,438,756	44,114,521	2,324,235	95
Secondary Voltage 10 - <50 kW	94,426,817	98,576,974	-4,150,157	104
Secondary Voltage ≥50 kW	352,218,949	367,737,239	-15,518,290	104
Primary Voltage <3 MW	29,189,906	30,473,403	-1,283,497	104
Primary Voltage 3 - <20 MW	51,704,287	53,977,832	-2,273,545	104
Primary Voltage ≥20 MW	62,622,337	65,380,102	-2,757,765	104
Transmission Voltage	14,194,875	14,818,365	-623,490	104
AE-Owned Private Outdoor Lighting	3,860,477	3,659,173	201,304	95
Non-Metered Lighting	176,279	167,461	8,818	95
Metered Lighting	852,526	809,927	42,599	95
Total	**1,136,020,803**	**1,136,040,848**	**-20,045**	**100**

Note:
1. Reflects the AED method for allocating production costs and excludes CAP funding.

By shifting some of the needed rate increase from customer classes greater than 25 percent below cost of service to customer classes less than 10 percent below cost of service, rate shock is minimized. Table 5.3 shows the increased needed to meet the proposed revenue target for each customer class. Effectively, this is AE's proposed average rate increase for each customer class. In the future, per City of Austin financial policies, AE will perform cost of service studies at least every five years. As these studies are routinely performed and rates are modified more frequently, variations between customer class revenue and cost of service results should diminish.

Table 5.3
Rate Increase Needed to Meet Proposed Class Revenue Target by Customer Class

Customer Class	Proposed Class Revenue Target ($)	Projected Revenue Under Existing Rates (1) ($)	Revenue Deficiency ($)	Increase Needed to Meet Target (2) (%)
Residential	456,325,851	373,304,903	83,020,948	22.2
Secondary Voltage <10 kW	44,114,521	36,421,201	7,693,320	21.1
Secondary Voltage 10 - <50 kW	98,576,974	91,141,558	7,435,416	8.2
Secondary Voltage ≥50 kW	367,737,239	349,970,012	17,767,227	5.1
Primary Voltage <3 MW	30,473,403	30,377,964	95,439	0.3
Primary Voltage 3 - <20 MW	53,977,832	47,083,898	6,893,934	14.6
Primary Voltage ≥20 MW	65,380,102	57,555,036	7,825,066	13.6
Transmission Voltage	14,818,365	15,816,915	(998,550)	-6.3
Service Area Street Lighting	N/A	N/A	N/A	N/A
AE-Owned Private Outdoor Lighting	3,659,173	1,955,348	1,703,825	87.1
Non-Metered Lighting	167,461	131,138	36,323	27.7
Metered Lighting	809,927	375,924	434,003	115.4
Total	**1,136,040,848**	**1,004,133,897**	**131,906,951**	**13.1**

Notes:
1. Adjusted for Test Year 2009 fuel.
2. Reflects the AED method for allocating production costs and excludes CAP funding.

The increased needed to meet the class revenue target for each customer class is slightly lower (by less than 1 percent for each class) than the proposed class rate increases noted in the rate design sections of this report as this calculation excludes funding for the Customer Assistance Program which is included in the proposed rate increase for each customer class.

Overview of Proposed Rate Design

Once revenue targets were established, AE designed rates for each customer class. This included a design of options for residential rates including an option that AE has identified as supported by this study. Under all residential rate options and for all commercial and industrial rates, an unbundled rate structure is being proposed to better recover the utility's costs, improve the fairness of rates, and improve pricing transparency. Using an unbundled rate design creates a pricing platform that supports emerging energy technologies and allows customers to better manage their electricity usage. This aligns with AE's strategic objectives and will allow the utility to fully leverage its investments in a new customer billing system and advanced metering.

An unbundled rate structure means that charges (e.g., customer, electric delivery charge, energy, etc.) are itemized on the bill to generally reflect the costs associated with each utility function and each charge is billed in a way similar to that in which the underlying costs are incurred. For instance, the customer charge is a fixed cost associated with metering, billing, collection services, and other customer service functions. In an unbundled rate design, these costs are recovered through a fixed $/month customer charge since there is no correlation between a customer's energy consumption or demand and their customer service needs.

This unbundled approach will mean changes in the way information is displayed on customer electric bills with charges being presented in a new, more informative way. These new charges are intended to improve transparency and understandability of rates. The addition of new charges does not necessarily mean that new costs are being recovered customers. Rather, these charges generally remove costs currently recovered through the energy charge as a separate line item. For instance, distribution costs are currently recovered through the energy charge for residential customers. Under the proposed unbundled rate structure, a portion of distribution costs would be shown separately on the bill in an electric delivery charge and these costs would be removed from the energy charge. Table 5.4 summarizes the line items in the proposed rate structure for residential, commercial, and industrial customers by cost type. The charge in which each cost type is currently collected is compared with the proposed charge for collection. For some cost types, the cost recovery mechanism is staying the same, with some naming of charges changing, while other cost types are recovered through new line items on the electric bill. A description of each charge follows.

Table 5.4
Comparison of Current Charges with Proposed Charges by Cost Type

Cost Type	Residential – Current Charges	Residential – Proposed Charges	Commercial / Industrial – Current Charges	Commercial / Industrial – Proposed Charges
Customer Service	Customer Charge	Customer Charge	Customer Charge (only for small businesses)	Customer Charge (all customers)
Distribution	Energy Charge	Electric Delivery Charge	Energy / Demand Charges	Electric Delivery Charge
Transmission	Transmission Cost Adjustment Rider / Energy Charge	Regulatory Charge	Transmission Cost Adjustment Rider / Energy Charge	Regulatory Charge
Production – Variable	Fuel Adjustment Clause	Energy Charge / Energy Adjustment	Fuel Adjustment Clause	Energy Charge / Energy Adjustment
Production – Fixed	Energy Charge	Energy Charge	Energy / Demand Charges	Energy / Demand Charges
Community Benefit Costs	Energy Charge	Community Benefit Charge	Energy Charge	Community Benefit Charge
Power Factor Corrections	N/A	N/A	Power Factor Adjustment (85 percent beginning in October 2011)	Power Factor Adjustment (90 percent)

Customer Charge

The Customer Charge recovers the cost of metering, billing, collecting, providing customer service, and all other customer-related costs. Austin Energy incurs these customer-related expenses from all customer classes. Austin Energy is proposing applying this charge to all customers on a $/month basis. Currently, a customer charge is only applied to residential and small commercial customers with demand less than 20 kW. Austin Energy currently recovers these costs from all other customers through the energy charge and demand charge.

Electric Delivery Charge

The Electric Delivery Charge recovers the cost of distribution substations, poles, wires, conductors, and transformers required to deliver power to customers. Austin Energy incurs these distribution function expenses from all customer classes that take service below the transmission level. Austin Energy is proposing to apply this charge to all non-residential customers on a $/kW basis and for residential customers on a flat $/month basis. For residential customers and small commercial customers with a demand less than 20 kW, AE currently recovers these costs through the energy charge.

Energy Charge

The Energy Charge recovers the cost of fuel, purchased power, and all other variable costs associated with the production of electricity. Additionally, the energy charge includes the unrecovered fixed costs from the customer, electric delivery, and/or demand charges. This charge is applied on a $/kWh basis for all customers. Under AE's current rate structure the cost of fuel and purchased power are not included in base rates as these costs are passed through to customers via the Fuel Adjustment Clause. Under the proposed rates, AE has included the full cost of fuel and purchased power in the energy charge for the Test Year, effectively netting the proposed Energy Adjustment to zero for the initial implementation of new rates. The structure of the re-defined Energy Adjustment is described below.

Seasonal Rates

Currently, AE applies a different energy charge during the summer months and the non-summer months to reflect the increased cost of producing electricity during the summer when demand on the system is higher and less efficient power generation resources are being used, leading to higher energy prices for customers. Currently, the summer rate period is the six months from May through October and the non-summer rate period is November through April. Austin Energy is proposing to redefine its summer on-peak pricing season as a four-month period from June through September. This approach is consistent with the four-month summer period used by ERCOT in its allocation of transmission costs and aligns better with AE's seasonal load profile and cost of service results. Therefore, the energy charge varies during the summer rate period (June-September) and the non-summer rate period (October-May) for each customer class.

Energy Adjustment

The Energy Adjustment replaces the current Fuel Adjustment Clause and would be netted to zero at the time new rates are implemented. Under this proposal, the Fuel Adjustment Clause would be re-named the Energy Adjustment in recognition that non-fuel items such as purchased power costs and margins generated from the wholesale power market are included in the calculation. With the approval of the Council, this pass-through charge can be adjusted without conducting a full rate review. The purpose of this type of pass-through charge is to ensure that the utility can fully recover these costs which can be substantial and are often outside of the utility's control. Historically, fuel-related costs have been highly variable year to year due to the inherent volatility of fuel markets. For instance, AE lowered its Fuel Adjustment Clause by 15 percent at the beginning of 2011 to reflect lower natural gas prices. Fuel and fuel-related costs can rise rapidly due to volatile fuel markets, industry regulation, the needs and desires of the local, national, and international community, and policy decisions.

Regulatory Charge

The Regulatory Charge recovers the regulated cost of AE's portion of statewide transmission expenses as well as all administrative grid operator fees. Currently for residential customers and small commercial customers with demand less than 20 kW, transmission expenses are recovered in the energy charge and the Transmission Service Adjustment Rider. The Transmission Service Adjustment Rider ("TSAR") only accounts for the incremental costs associated with new transmission build-out in Texas so the Regulatory Charge would replace this temporary rider. For commercial and industrial customers these costs are currently being recovered through the demand charge and the TSAR. ERCOT administration fees are currently recovered through the fuel adjustment clause for all customers. Costs recovered through the Regulatory Charge would be removed from their existing charges in this rate design. It is appropriate to separate these costs as a pass-through charge because these costs can vary by year due to regulatory decisions that are beyond AE's control. Additionally, showing these costs separately as a line item on the customer bill improves the transparency of these costs.

Community Benefit Charge

The Community Benefit Charge recovers certain costs incurred by the utility as a benefit to AE's customers and the greater community. This includes costs to support utility bill assistance for CAP participants, service area street lighting, and the cost of AE's energy efficiency, green building, and solar rebate programs. It is appropriate to separate these costs as pass-through charges because these costs can vary by year due to budget needs. Additionally, showing these costs separately as line items on the customer bill improves the transparency of these costs.

Demand Charge

The Demand Charge recovers fixed production costs related to building and financing AE's existing and new power plants. Using a demand charge best reflects the way in which these costs are incurred and provides an incentive for customers to reduce their load by making energy efficiency improvements or controlling their demand. Austin Energy incurs these production costs from all customer classes based upon the demand of each customer. Because applying a demand charge requires metering equipment not currently in place for the majority of residential customers, they are not assessed a demand charge and instead these costs will be recovered in the energy charge as is currently done.

Because all commercial and industrial customers currently have demand meters, AE's rate proposal applies a demand charge for all commercial and industrial customers regardless of size. This charge is applied on a $/kW basis. The charge varies by season (summer versus non-summer rate period) to reflect the differences in costs to produce electricity during these time periods. Currently, small commercial customers with demand less than 20 kW are not applied a demand charge. These costs are recovered as a component of their energy charge. For this reason, AE is proposing a three-year phase-in of the demand charge for commercial customers that are not currently billed demand. This includes Secondary Voltage customers <20 kW, worship customers, and City of Austin accounts.

Power Factor Adjustment

Austin Energy is implementing a power factor adjustment of 85 percent for commercial and industrial customers currently billed a demand charge beginning in October 2011. As part of this rate review, AE is proposing increasing this adjustment to 90 percent upon implementation of new rates. Power factor is a measure of efficiency that reflects the amount of real power delivered and used by a customer. Real power is electricity that can actually be used to perform work such as running a motor or heating an oven. For an equivalent amount of real power, customers with low power factors require more electric current to be delivered by a utility than high power factor customers. 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 should be reflected in their rates.

Projection of Future Revenues

Austin Energy's rate proposal is designed to fully recover the target revenues in the first year new rates are implemented with the exception of revenues associated with the needed rate adjustment for 15 of AE's largest commercial and industrial customers who are currently being served under special contract terms that run through May 2015. Under this rate proposal contract customers would be priced at the proposed rates once their contracts expire. Until that time, AE will be under-recovering on average $20.8 million annually from these customers, resulting in a total of $76.1 million in lost revenue by June 2015. The impact of these revenue losses is reflected in Table 5.5. Table 5.5 also shows the amount of revenue generated by each customer class through FY 2016 under the rate proposal assuming TY sales levels remain unchanged.

Table 5.5 shows that AE will not realize the full revenue increase associated with the proposed rates until 2016. Approval of rates as presented in this proposal will help meet the financial needs of the utility, but not fully cover its full cost of service until 2016. Therefore, AE will need to continue to constrain its budget and/or use a portion of its cash reserves to minimize its annual budget gap until 2016.

Table 5.5
Summary of Revenue Projections Under Proposed Rates Through FY 2016

		Revenue Under Proposed Rates				
Customer Class	Target Revenue for Rate Design	FY 2012[1]	FY 2013	FY2014	FY2015	FY 2016
Residential	480,335,595	456,325,851	456,325,851	456,325,851	456,325,851	456,325,851
Secondary Voltage <10 kW	46,438,756	44,113,902	44,113,972	44,114,521	44,114,521	44,114,521
Secondary Voltage 10 - <50 kW	94,426,817	98,576,609	98,575,786	98,576,974	98,576,974	98,576,974
Secondary Voltage ≥50 kW	352,218,949	361,129,622	361,127,530	361,129,241	363,331,907	367,737,239
Primary Voltage <3 MW	29,189,906	30,155,982	30,155,982	30,155,982	30,261,789	30,473,403
Primary Voltage 3 - <20 MW	51,704,287	47,655,072	47,655,072	47,655,072	49,762,659	53,977,832
Primary Voltage ≥20 MW	62,622,337	57,555,036	57,555,036	57,555,036	60,163,391	65,380,102
Transmission Voltage	14,194,875	15,121,035	15,121,035	15,121,035	15,020,145	14,818,365
AE-Owned Private Outdoor Lighting	3,860,477	3,659,173	3,659,173	3,659,173	3,659,173	3,659,173
Non-Metered Lighting	176,279	167,461	167,461	167,461	167,461	167,461
Metered Lighting	852,526	809,927	809,927	809,927	809,927	809,927
Total	**1,136,020,803**	**1,115,269,671**	**1,115,266,827**	**1,115,270,275**	**1,122,193,799**	**1,136,040,848**
Current Rate Revenue	1,004,133,897	1,004,133,897	1,004,133,897	1,004,133,897	1,004,133,897.47	1,004,133,897
Difference	131,886,905	111,135,774	111,132,929	111,136,377	118,059,901.93	131,906,951
Percentage Difference	13.1	11.1	11.1	11.1	11.8	13.1
Under recovery associated with Special Contract Customers		-20,751,131	-20,753,976	-20,750,528	-13,827,003.37	20,046

Note:
1. Assumes proposed rates are in effect for the entire fiscal year. Revenue projections dependent on the date of implementation of new rates.

Section 6
RESIDENTIAL RATE DESIGN

This section provides analysis in support of the proposed rate structure and rates for AE's residential customer class. A discussion of three additional residential rate options for consideration during the public review process of this rate proposal is also included in this section. These options generally maintain the unbundled rate structure proposed by AE, but provide some options for the prices set for the fixed charges in the customer charge and the electric delivery charge (with one option showing a basic monthly charge in lieu of these two charges), the number of tiers, and the price for each tiers. Each option is revenue-neutral, meaning that each option meets the target revenue for the residential customer class presented in Section 5 of this report.

Residential Rate Design Objectives

The residential rate structure proposed by AE is designed to meet the following objectives that align with AE's rate design principles described in Section 5 of this report:

- Set rates closer to the cost of service for the residential customer class, thereby minimizing inter-class subsidies.
- Improve fixed cost recovery, thereby minimizing intra-class subsidies, particularly between the smallest and largest electricity users in the residential class.
- Create a rate structure that is stable yet flexible enough to ensure the relevance of the rate structure into the foreseeable future and allow the utility to achieve its long-term residential pricing objectives.
- Improve pricing signals that encourage conservation and promote investment in home energy efficiency improvements.
- Provide a discount to low-income customers who face the greatest challenges in paying for electricity service.
- Improve pricing transparency and develop a rate structure that is practical and understandable to customers.
- Offer residential customers rate alternatives that support customer behavior and technology adoption that is beneficial to the environment and the utility system, including rates that support renewable energy, electric vehicle and solar PV consumer adoption, and promotion of shifting electricity usage from on-peak periods (which represent periods of higher system cost) to off-peak periods (representing periods of lower system cost).
- Protect the utility from uncontrollable events or circumstances by maintaining and establishing pass-through charges associated with market power and regulatory costs, including fuel-related costs.

The biggest challenge facing AE in redesigning electric rates for residential customers is developing a rate structure that ensures full recovery of the utility's fixed costs for providing electric service and minimizes inter-class subsidization that is not intended to promote energy efficiency and conservation objectives. Fixed costs are expenses incurred by the utility regardless of how much electricity a customer uses. Currently, the only fixed charge that a residential customer pays is a $6 per month customer charge. The remainder of the utility's fixed costs are recovered through a variable energy rate, based on a customer's monthly electricity consumption. Cost of service results for the Residential customer class show that the fixed costs associated with customer service and electric delivery (distribution) total over $35 a month per customer. This means that the utility is not fully recovering the fixed costs to serve low-usage customers and high-usage customers are currently subsidizing a portion of these costs for low-usage customers. If AE were to raise its rates to reflect the full cost of service, the customer charge would be increased from $6 to $22 and the electric delivery charge would be set at $14. These costs would then all be removed from the energy charge. Such a rate change would disproportionately impact low-usage customers as these customer would benefit only slightly from a lower energy charge compared to the added cost associated with the higher fixed monthly charges.

In order to move closer to cost of service-based rates, but recognizing the need to mitigate rate shock for low-usage customers, AE is proposing increasing the residential customer charge to $15 and adding an electric delivery charge of $10 for a combined total of $25 per month. Effectively, this serves as a minimum electric bill for residential customers. The remaining fixed customer service and distribution costs not recovered in those charges will be included in the energy charge. This change in residential rate design will improve fixed cost recovery, however low-usage customers will continue to receive some subsidization from higher-usage customers for these costs. The portion of fixed costs currently being recovered through the variable energy charge will be removed from the energy charge, thus offsetting the magnitude of the proposed energy charge.

Austin Energy is also proposing converting from the current two-tier rate structure to a five-tier rate structure to further encourage and reward customers for being energy efficient and conserving energy. Energy efficiency and conservation help keep bills lower for all customers by delaying or offsetting the need for additional power plants and system expansion. Inclining tiers also ensure that those who use the greatest amount of electricity pay their fair share of the extra cost for power generation and system sizing needed to serve them. The five-tier rate structure is designed to support complementary AE programs that provide rebates and other incentives for investing in energy efficiency and solar PV systems. The rationale behind this design is also provided in this section of the report.

Current Rate Structure and Prices

The residential rate applies to residential customers in single-family dwellings, mobile homes, town houses, and apartment units. Austin Energy's current residential rate structure is a two-tier inclining block rate structure. Residential customers currently pay 3.55 cents per kWh for the first 500 kWh of electricity consumption, with the energy charge increasing to 6.02 cents per kWh during the currently defined winter rate period (November–April) and 7.82 cents per kWh during the currently defined summer rate period (May–October) for each kWh used over 500 kWh. Presently, fixed cost recovery is limited to a $6 per month customer charge.

The existing residential rate structure also includes two pass-through charges. The fuel adjustment charge directly passes fuel-related costs on to the customer. Alternatively, customers can choose to purchase 100 percent renewable energy through AE's GreenChoice program. For GreenChoice subscribers the renewable energy rate is applied in lieu of the fuel adjustment charge. The other existing pass-through charge is the TSAR which was implemented in October 2010 to recover incremental costs associated with new transmission build-out in Texas. Table 6.1 summarizes AE's existing residential rate structure.

Table 6.1
Residential Customer Class –
Summary of Existing Rate Structure and Prices(1)

Item	Winter Rate Period (November - April)	Summer Rate Period (May - October)
Customer Charge ($/month)	6.00	6.00
Energy Charge (¢/kWh)		
First 500 kWh	3.55	3.55
All Over 500 kWh	6.02	7.82
Pass-Through Charges (¢/kWh)		
Fuel Adjustment Charge (adjusted for TY) (2)	3.398	3.398
Transmission Service Adjustment Rider	0.082	0.082
GreenChoice		
Batch-1 (3)	1.700	1.700
Batch-2 (3)	2.850	2.850
Batch-3	3.300	3.300
Batch-4	3.500	3.500
Batch-5	5.500	5.500
Batch-6	5.700	5.700

Notes:

1. Austin Energy manages the Customer Assistance Program, which provides utility bill discounts to qualifying low-income customers. Discounts provided by this program include the waiving of AE's $6.00 per month customer charge and charging 1.7 cents per kWh, in lieu of the current fuel charge (3.105 cents per kWh). The 1.7 cents per kWh low-income rate was based on the Batch-1 GreenChoice rate which expired in March 2011, but continues to be applied today. This amounts to an average monthly discount of

about $20 for a customer using 1,000 kWh a month on average given the current fuel adjustment charge, which was updated in January 2011.

2.The Fuel Adjustment Charge used for comparison purposes is based on the normalized TY revenue requirement results (TY 2009 fuel adjustment charge of 3.398 cents per kWh). The Fuel Adjustment Charge varies. As of August 29, 2011 it was 3.105 cents per kWh for residential customers.

3. The Batch-1 and Batch-2 GreenChoice rates expired March 2011.

Challenges Identified in Existing Rate Structure

Austin Energy staff reviewed AE's existing residential rate structure with consideration of the utility's strategic objectives and obtained public input to identify challenges with the utility's existing residential rates. For the residential rates, identified challenges to address in this rate review included the following:

- Existing residential rates do not sufficiently recover the cost to serve this class and the rate structure does not reflect the cost to serve customers within this class.
- Fixed cost recovery is limited in the existing residential rate structure and subjects AE to considerable revenue instability due to changing and unpredictable weather variations and declining load growth.
- The existing residential rate structure provides limited flexibility to modify rates and charges to reflect changes in AE's cost of service over time.
- The existing two-tier inclining block residential rate structure provides limited pricing signals to encourage conservation and promote energy efficiency improvements.
- Assistance provided by AE's Customer Assistance Program is not available to many low-income customers facing challenges in paying for electricity service and the existing Customer Assistance Program discount structure provides reduced conservation pricing signals to existing participants.
- The residential rate structure should transparently reflect AE's cost of service.
- The existing summer rate period does not align with AE's peak demand period and does not adequately reflect peak demand costs.
- The residential rate structure should support technology adoption and customer choice through rate alternatives beneficial to both the environment and the utility.
- The residential rate structure should protect AE from uncontrollable events or circumstances by way of pass-through charges that automatically change to reflect AE cost changes, including changes in fuel and energy market-related costs.

Process Used to Address Residential Rate Challenges

Austin Energy staff, along with its hired ratemaking experts, carefully reviewed rates research, completed new analysis, and obtained public input during the rate review process to address the identified residential rate challenges. This information allowed the utility staff to develop proposed rates that achieve the class' cost of service while meeting the utility's strategic objectives and customer preferences. A balancing of sometimes conflicting objectives was completed as part of this iterative process to address the challenges with current residential rates. Components of AE's rate proposal for residential customers that address these challenges include the following:

- Help AE achieve its revenue requirement by adjusting residential rates to 95 percent of the identified cost of service for this customer class.
- Improve fixed cost recovery by increasing the customer charge and introducing a fixed electric delivery charge and removing these costs from the variable energy charge.
- Encourage energy efficiency and conservation by changing from the current two-tier inclining block inclining rate structure to a five-tier inclining block rate structure and changing from the current six-month summer rate period to a four-month summer rate period.
- Help provide affordable energy and mitigate rate impacts within the customer class by phasing in rates to cost of service levels, by setting rates so that most residential customers will see average monthly electric bill increases of less than $20 per month, and by increasing funding for the Customer Assistance Program
- Improve customer understandability and transparency of rates by unbundling rates to more closely reflect the costs to provide services; this includes introducing an electric delivery charge, a regulatory charge, and a community benefit charge.

The process for determining the first component of this proposal was discussed in Section 5 of this report. How the components of AE's proposal for residential rates supported by this report were derived is discussed in greater detail in this section of the report.

Proposed Standard Residential Rate Structure and Prices

Austin Energy's proposed residential rate structure includes a customer charge, electric delivery charge, energy charge, energy adjustment clause, regulatory charge, and community benefit charge. These charges are described in Section 5 of this report. With respect to the energy charge, AE is proposing to move from a two-tier to a five-tier inclining block rate structure. By increasing the number of tiers, stronger pricing signals are sent to larger consumers of electricity, sending stronger signals for those customers to conserve electricity. Higher rates paid by large users improve the economic incentive to invest in home energy efficiency improvements for high-usage consumers.

Table 6.2 shows the proposed modification in the energy blocks from the existing residential rate structure. Under the current two-tier rate structure, the break point between the lower priced and higher priced tiers is 500 kWh. However, average monthly consumption for AE residential customers is approximately 1,000 kWh, so most of AE's residential customers will pay for some consumption at the second tier rate. A five-tier rate structure allows for stronger pricing signals to be sent to the largest consumers of electricity.

Table 6.2
Existing Two-Tier vs. Proposed Five-Tier Energy Block Rate Design for Residential Rate Design Supported by the Rate Analysis and Recommendations Report

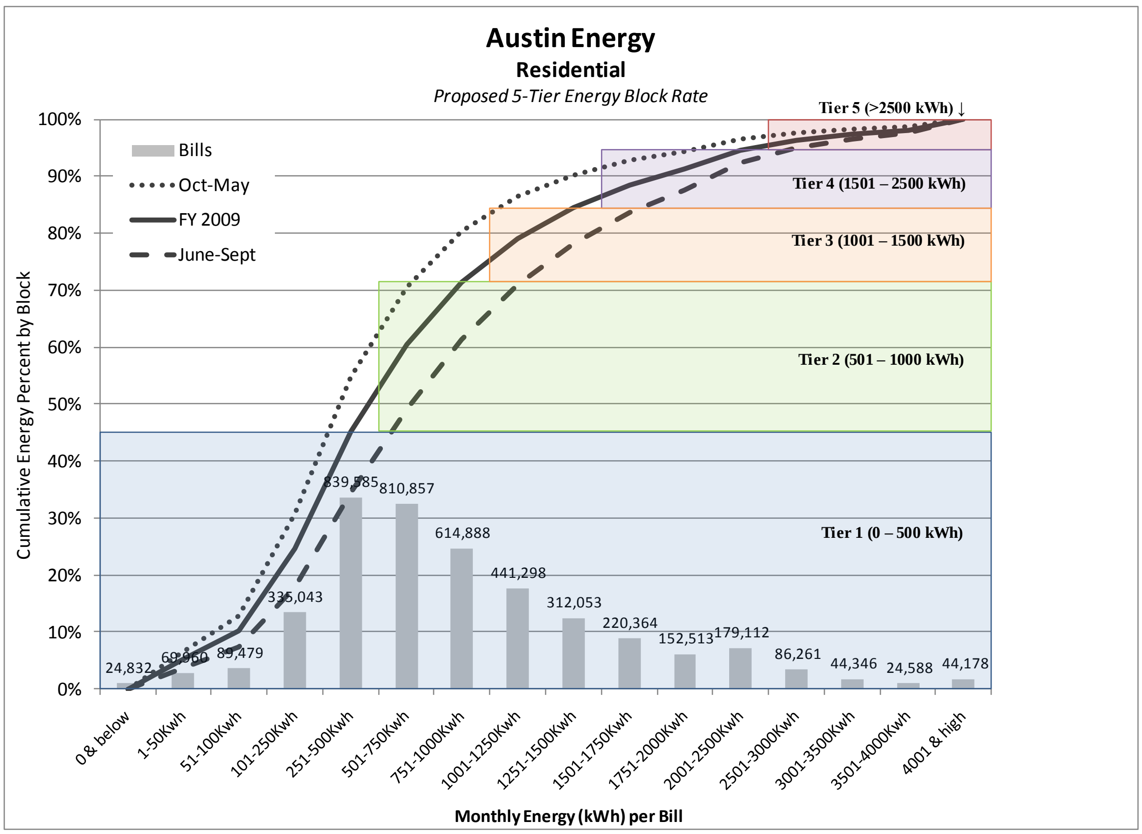
Energy Block	Percentage of Bills (%)	Existing	Proposed
0-500 kWh	32	Tier 1	Tier 1
501-1,000 kWh	33	Tier 2	Tier 2
1,001-1,500 kWh	18	Tier 2	Tier 3
1,501-2,500 kWh	13	Tier 2	Tier 4
> 2,500 kWh	5	Tier 2	Tier 5

The setting of each tier, or block of electricity usage, was determined by reviewing several sources of data related to residential customer electricity usage and opportunities for residential customers to achieve energy savings. Austin Energy first analyzed data on the home building stock in its service territory and participant data for AE's energy efficiency and solar rebate programs. This analysis demonstrated that customers who participate in AE's most comprehensive energy efficiency programs (Home Performance with ENERGY STAR, Free Weatherization, and the air conditioning rebate program) tend to achieve average energy savings of about 500 kWh per month during summer months and over 300 kWh in average savings per month over the year. Additionally, the average monthly output from a typical residential customer solar PV system is about 500 kWh a month. These findings suggest that setting the initial first, second, and third tiers in 500 kWh increments aligns well with AE's complementary programs that align with the utility's strategic objectives. By participating in AE's energy efficiency programs or adopting solar PV, many residential customers should be able to move into a lower tier block for much of the year. Since residential customers consume about 1,000 kWh on average, investing in solar PV or making energy efficiency improvements can move a customer into the first tier, or lowest priced tier, all other things equal.

To define the appropriate cut-off points for the higher tiers (fourth and fifth tiers), AE analyzed average customer usage based on the premise that, even during the June through September summer rate period, the tiers should be set such that an average residential customer will not fall into the two highest tiers. Average summer usage (June-September) for customers with a year's worth of uninterrupted billing data was 1,345 kWh and average usage during the non-summer months (October-May) was 761 kWh. Given this information, 1,500 kWh appears to be an appropriate starting point for the fourth tier. The fifth tier was determined by targeting the highest 5 percent of residential customer class energy usage to minimize the number of customers who are impacted by the highest rate tier. This is achieved by setting the fifth tier at all consumption above 2,500 kWh.

Following this analysis, AE looked at the relationship of these tiered blocks to AE's residential customer class usage data. Using FY 2009 data, Figure 6.1 shows the cumulative average monthly electricity usage per residential customer in the proposed summer (June-September) and non-summer (October-May) rate periods as well as an annual monthly average. The bars show the bill frequency over the course of the year with break points for five blocks. Please note the differences in the range of the blocks (i.e., 101-250 kWh versus 2,001–2,500 kWh) across the x-axis, as a consistent range is not used due to the low number of bills in each tail end of the chart. The five tiers are depicted by different colors of horizontal blocks to indicate the cumulative percentage of energy usage falling within each block and the number of electricity bills.

Figure 6.1
Five-Tier Energy Block Rate Analysis



The first tier in the five-tier option (<500 kWh) is the same as the existing two-tier rate structure and captures slightly less than half of the annual energy consumption of the residential customer class (45 percent) and about 32 percent of the total number of annual residential customer bills. The second tier (501-1,000 kWh) cumulatively includes about 71 percent of the annual customer class energy consumption and about 65 percent of annual customer bills. Cumulatively, the third tier (1,001-1,500 kWh) captures 85 percent of the annual customer class energy consumption and about 83 percent of annual customer bills. The fourth tier (1,501–2,500 kWh) includes about 95 percent of the class energy consumption and about 95 percent of the residential customer bills. All remaining residential usage and customer electric bills fall within the fifth tier (monthly energy consumption over 2,500 kWh).

Austin Energy believes that the setting of tiers at these break points ensures that only the highest usage customers who have the greatest opportunity for conserving electricity and making home energy efficiency improvements are affected by the two highest tiers. These tiers will provide support for AE's marketing of rebates and other incentives to make home energy efficiency improvements and invest in solar PV as the payback period for these investments will be improved.

Once the tiered blocks were determined, AE was able to determine the prices for each tier to complete the residential rate design. These prices are based on the unit cost of service results presented at the end of Section 4 of this report (and adjusted to reflect 95 percent of cost of service for the residential class), as using these results ensures that the residential rates fully recover the residential class cost of service. Table 6.3 compares AE's current two-tier residential rate structure and prices with the proposed five-tier residential rate structure and prices.

Table 6.3
Residential Rate Structure and Prices Comparison:
Existing vs. Proposed Rate Supported by Report

Name of Charge/Rate	Existing Rates with Adjusted TY Fuel (1)	Cost of Service	Proposed Five-Tier Option Supported by Report
Customer Charge ($/month)	6.00	21.69	15.00
Electric Delivery Charge ($/month)	n/a	14.13	10.00
Energy Charge (¢/kWh) (2)			
Summer (June - September) (3)			
< 500 kWh	6.948	7.504	5.514
501-1000 kWh	11.218	7.504	9.514
1001-1500 kWh	11.218	7.504	12.014
1501-2500 kWh	11.218	7.504	13.514
>2500 kWh	11.218	7.504	14.514
Non-Summer (October - May) (3)			
< 500 kWh	6.948	6.968	4.411
501-1000 kWh	9.418	6.968	7.611
1001-1500 kWh	9.418	6.968	9.611
1501-2500 kWh	9.418	6.968	10.811
>2500 kWh	9.418	6.968	11.611
Energy Adjustment (¢/kWh) (4)	n/a	0.00	0.00
Community Benefit Charge (¢/kWh) (5)			
Customer Assistance Program (¢/kWh)	n/a	0.065	0.065
Service Area Street Lighting (¢/kWh)	n/a	0.114	0.114
Energy Efficiency Charge (¢/kWh)	n/a	0.301	0.301
Transmission Service Adjustment Rider (¢/kWh) (6)	0.082	n/a	n/a
Regulatory Charge (¢/kWh) (7)	n/a	0.729	0.729
Overall Rate Increase (%)		22.9	22.9

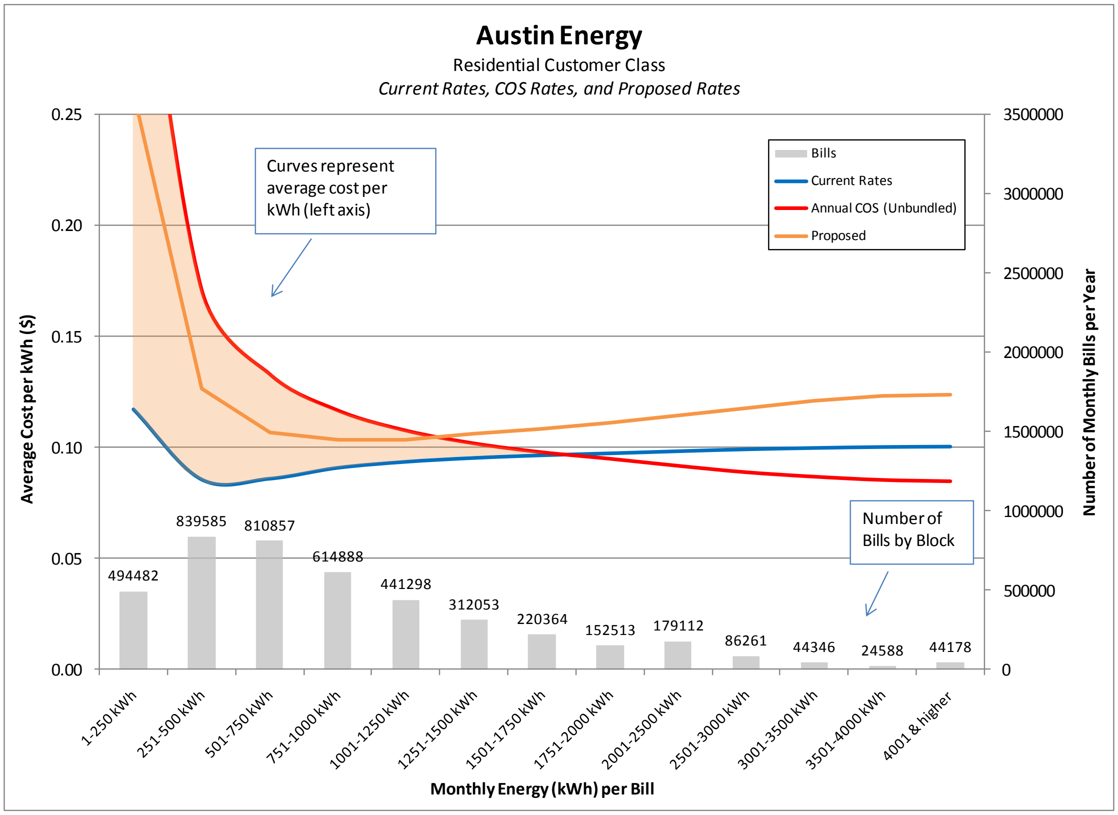
Notes:
1. For the purposes of rate comparisons, the Fuel Adjustment Charge used in the rates is 3.398 cents/kWh based on the normalized TY revenue requirement results.
2. AE's existing Energy Charge does not include fuel-related costs. Fuel is charged separately through the Fuel Adjustment Clause. The Energy Charge shown here includes fuel-related costs based on the normalized TY revenue requirement results (TY 2009 fuel adjustment charge is 3.398 cents per kWh) as these costs are not part of the requested base rate increase.
3. The summer season under the current rate structure is from May through October; the non-summer season under the current rate structure is from November through April. Under the proposed rate structure, summer season would be June through September and non-summer season would be October through May.
4. The Energy Adjustment is a new charge that replaces the current Fuel Adjustment Clause. The Energy Adjustment is set to zero but is subject to change as described in Section 5 of this report.
5. The Community Benefit Charge is a new charge that funds three specific programs and services provided to the community by AE. The Customer Assistance Program creates monies to provide discounts to qualified low-income and other disadvantaged customers. Service Area Lighting recovers the cost of street lighting to customers within the entire AE service territory.
6. The Transmission Service Adjustment is a current charge associated with AE's increased cost of ERCOT transmission to support State transmission build-out. This adjustment would be discontinued under the proposed rate structure and these costs would be included in the new Regulatory Charge.
7. The Regulatory Charge is a new charge that replaces the Transmission Service Adjustment Rider and includes ERCOT administration fees and charges associated with AE's cost of ERCOT transmission.

This comparison shows that while AE is proposing to increase the fixed charges (the customer and electric delivery charges) and add new variable pass-through charges (the regulatory and community benefit charges) applied to residential customers, prices for the first two tiers under the energy charge including fuel are less than the current prices for the components of this charge. This helps to mitigate the impact of the proposed rate adjustment for residential customers who consume at or near the average amount of electricity for AE residential customers. Prices for the higher tiers, with the majority of usage being above average, are higher than current prices in order to send pricing signals to promote energy efficiency, conservation, and improve the economic incentive associated with distributed renewable alternatives such as solar PV. Under the proposed five-tier structure, the differential between the lowest and highest tier is 7.2 cents per kWh in the non-summer rate period and 9 cents per kWh in the summer rate period.

Residential Customer Bill Impact Analysis

Within the residential customer class, the cost to serve customers in terms of cents per kWh varies based on monthly energy consumption. Figure 6.2 depicts that variation by monthly consumption. Using the cost of service study results, a cost of service curve, or cost curve, was constructed to compare the average cost, in cents per kWh, of serving each customer within the residential customer class based on monthly electricity consumption. The cost of service curve is the red line in Figure 6.2. This curve is compared with the existing rate curve (blue line) and the proposed rate curve (orange line). The shaded pink area indicates the gap in the cost of service and current rates which illustrates the fixed cost recovery problem discussed above. The grey bars represent the bill frequency results for residential customers previously discussed in Section 3 of this report. The bill frequency distribution shows the number of residential electricity bills during FY 2009 for various ranges of monthly electricity usage represented on the x-axis. 250 kWh blocks (i.e., 1-250 kWh) are represented in Figure 6.2 through 2,000 kWh at which point the blocks increase to 500 kWh block increments (i.e., 2,001–2,500 kWh) until the category of all bills greater than 4,000 kWh.

Figure 6.2
Cost and Rate Curves Comparison for Residential Rates: Current vs. Cost of Service vs. Proposed Rates



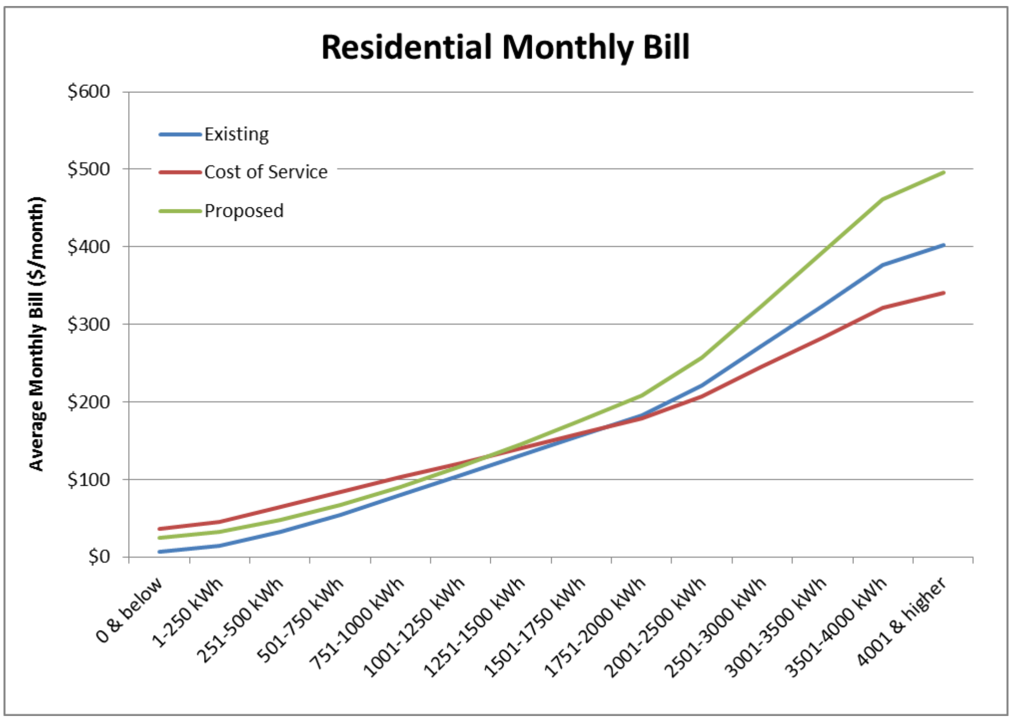
The shape of the cost curve reflects a typical cost curve for any customer class. As customers use more energy, the average cost of service (represented in $/kWh) typically decreases. This is because fixed costs that a utility incurs in order to serve a customer are borne regardless of customer monthly electricity usage. Customers that use more energy have a lower average cost of service as fixed costs are recovered over a greater number of units of electricity consumed (in kWh). Conversely, customers who use little energy have a higher average cost of service as fixed costs are recovered over few kWh.

The cost curve gradually decreases and then flattens out as more electricity is consumed and costs are spread out among more units of electricity (kWh). However, the utility's actual rate may show costs increasing per kWh if fixed costs are not fully recovered from the low-usage customers. This occurs because of the rate structure and the reality that in total, all costs associated with serving the customer must be recovered. To the extent that fixed costs are not fully recovered through fixed charges, they must be recovered in the variable energy rate. Under AE's existing rates, the average rate per kWh begins to rise at 500 kWh and then flattens out as more kWh are used. This occurs because the current two-tier rate structure prices the first 500 kWh of usage at a lower rate than the rate charged for each unit of consumption above 500 kWh.

Under AE's proposed five-tier rate structure, the average rate per kWh continues to rise rather than flattening out because of the increase in rates at each higher block of consumption. Eventually the curve flattens out, but at a much higher level of consumption than under the existing rate structure. The proposed rate for the residential customer class is below the cost of service curve for usage under approximately 1,250 kWh per month, however, it is above the current rate as this class is currently under-paying for electric service.

The average cost per kWh can be somewhat misleading when comparing low-usage customers with high-usage customers since fixed costs are either spread out among very few kWh or numerous kWh. An examination of monthly electric bills depending on electricity consumption is a complementary data point to the cost and rate curves. Figure 6.3 shows average monthly residential electric bills priced at cost of service compared to bills at existing rates and bills at proposed rates based on average monthly consumption. In Figure 6.3 the usage block ranges on the x-axis are the same as those used in Figure 6.2. Results are shown in dollars per month ($/month) for a monthly residential electric bill.

Figure 6.3
Residential Customer Class Monthly Electric Bills at Cost of Service vs. Current Rate and Proposed Rate



As demonstrated by the cost of service curve in red, the average monthly cost to serve residential customers ranges from approximately $36 a month, for customers who use no electricity, to over $340 a month for users of at least 4,000 kWh of electricity. The existing residential rate charges customers with no usage $6 a month and customers who use at least 4,000 kWh of electricity $400 a month on average. Under AE's proposed rate, customers with no usage would pay $25 a month and the customers with usage of 4,000 kWh or greater would pay at least $495 a month on average.

Table 6.4 compares annual average monthly residential electric bills at various levels of electricity usage under the existing residential rate and the proposed residential rate. Various levels of electricity usage are presented to show a diverse range of customer bills. More extensive electric bill comparison data is included in Appendix F of this report.

Table 6.4
Annual Average Monthly Residential Electric Bill Comparison At Various Levels of Electricity Usage

	250 kWh	750 kWh	1,000 kWh	1,500 kWh	2,500 kWh	4,000 kWh
Cumulative Customer Electric Bills (% of Total)	12	51	65	82	95	99
Current Bill Adjusted for TY Fuel ($)	23.37	66.53	92.33	143.92	247.10	401.86
Proposed Bill ($)	39.97	78.58	102.21	160.32	289.53	496.35
Difference ($)	16.60	12.04	9.88	16.40	42.43	94.48
Percent Change (%)	71	18	11	11	17	24

The proposed residential rate design is structured to improve fixed cost recovery by increasing the fixed charges while minimizing the rate increase for all residential electric bills under 1,500 kWh of consumption to below $20 a month on average. Over 80 percent of customer electric bills are below 1,500 kWh. These results indicate that average annual electric bills for customers with average or below average consumption (1,000 kWh per month or less) will increase between $10-$17 per month. High usage residential customers (1,500 kWh per month or greater) will see increases in their electric bills of between $16-$94 per month. It should be noted that due to the seasonal nature of the rate structure, in the summer rate period the increases in monthly electric bills will be greater than the average shown and during the non-summer rate period they will be less than the average.

The results are directly related to the residential rate structure. Improved fixed cost recovery related to higher customer and delivery charges adds $19 per month to low-usage customers. This result yields a higher percentage increase in the monthly bill for low users although the dollar per month increase is comparable to other AE customers with usage at or below 1,500 kWh per month. Residential customers who consume large amounts of electricity will see a larger percentage increase in their monthly electric bill. This is a direct result of the inclining block rate structure and the energy efficiency and conservation pricing signals embedded in that structure.

Proposed Customer Assistance Program Funding Mechanism

Austin Energy manages a comprehensive Customer Assistance Program to help customers on low and/or fixed incomes cope with 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. As demonstrated in the affordability study completed by SAIC (formerly R. W. Beck) and AE in the fall of 2010, the discount program results in rates for low-income customers that are among the lowest in the state. The program is open to residential customers if anyone in their household receives benefits from one of the following assistance programs: certain types of state Medicaid, state-paid Medicare, Supplemental Security Income, Travis County Hospital District Medical Assistance Program, or Travis County Energy Assistance Program.

Austin Energy and other City of Austin utility departments provided approximately $4.7 million in utility bill discounts (about $3.1 million in electric bill discounts) to 9,949 low-income customers in 2010. Today, AE's Customer Assistance Program serves approximately 10,000 customers. Discounts currently provided by this program include the waiving of AE's $6.00 per month customer charge and applying a 1.7 cents per kWh fuel charge in lieu of the current fuel charge (3.105 cents per kWh), a discount of about half the standard fuel charge. In 2009, this discount structure resulted in an average monthly discount of $26 for a customer using 1,000 kWh. Additionally, emergency utility bill payment assistance totaling $312,090 was also provided in 2010 to 1,833 households facing financial crises due to unemployment, health issues, or other emergencies. The emergency assistance is provided through a partnership with social service agencies that receive utility assistance requests. Austin Energy's comprehensive Customer Assistance Program helps customers not only in the area of financial assistance but also with energy efficiency improvements through its free weatherization program for income-eligible customers.

Beginning in January 2011, the Community Advocacy Group (CAG)[6] met monthly to discuss the low-income discount program and provide input into the rate review process. Input provided by this group and the Rate Review PIC, including a proposal presented at the PIC by the Residential Rate Advisor were considered in the development of AE's proposal for a new funding mechanism for Customer Assistance Program. The proposed funding mechanism for this program is the application of a 0.065 cents per kWh charge to all customers that is shown as a line item on the customer electric bill under the Community Benefit Charge. This is similar to the structure of the low-income customer discount funding mechanism applied by the State of Texas in competitive markets. A 0.065 cents per kWh charge is applied to all customer electric bills in the competitive market to support the State System Benefit Fund which supports utility bill discounts to low-income customers and other purposes.

[6] A group of representatives of social service agencies and low-income customer advocates formed in 2010 by AE to discuss customer issues.

Based upon AE's total normalized electricity sales of 11.8 billion kWh in TY 2009, this funding mechanism would generate approximately $7.7 million, more than double existing funds for this program. This increased funding will allow AE to provide electric bill discounts and free weatherization funds to a greater number of customers in need of assistance.

Other Residential Rate Design Options

Austin Energy prepared several rate design options for residential customers. While these different options are all designed to recover the full revenue requirement associated with residential electric service in the Austin community, they vary in some important ways. All Austin Energy residential rate options seek to recover more of the cost of service from fixed charges than was the case in the 1994 rates. As Table 6.5 shows, none of the options seek to implement rates strictly according to the cost of service analysis. The utility's goal is to implement rate redesign as close to cost of service as possible. Strict implementation would be impractical.

All Austin Energy residential rate design options continue the long-standing structure of providing a lower rate for the first tier of usage to encourage conservation and support efficient energy use. Some of the options include additional rate levels or tiers, with the rate increasing progressively as customers increase total energy use. This design feature encourages even more efficient use of energy by providing customers with a real savings incentive. Table 6.6 provides additional comparative information about the residential rate design options.

Components of the residential rate structure that are flexible in the rate design include the amount of the fixed charges (recognizing AE's need to improve fixed cost recovery in order to align with the utility's Strategic Plan) and the number, size, and rate levels for each block of the tiered block rate structure. The energy charge is used to recover any costs that are not fully recovered in other applicable charges. Thus, any reduction or removal of a fixed charge results in a proportionate increase in the energy charge. Likewise, any reduction or removal of the community benefit charge or the regulatory charge would result in a proportionate increase in the energy charge.

Existing Rate with Adjusted TY Fuel – Describes AE's existing residential rate adjusted for test year fuel costs to maintain consistency with the optional scenarios. The energy charge includes AE's current energy charge and the fuel adjustment clause adjusted for the Test Year cost of service results.

Cost of Service – Describes the results of the cost of service study completed for this rate review for the Residential customer class.

Option Supported By Rate Analysis and Recommendations Report (Option A) – Describes AE's proposal which is presented in this report and supported by the underlying rate analysis presented above as the best business case to achieve cost of service while meeting AE's rate review objectives.

Shift Greater Fixed Costs to Energy Charge (Option B) – This scenario lowers the proposed customer charge from $15 to $10 and passes those costs to energy users with consumption above 1,000 kWh. This results in lower electric bills for low and average users and higher electric bills for high users compared to Option A.

Maintain Current Energy Rates with New Fixed Charges (Option C) – This scenario maintains the current energy rates (energy charge and the fuel adjustment clause adjusted for the Test Year cost of service results) under the current two-tier inclining block rate structure (which includes lower prices for the first 500 kWh of usage), applies the community benefit charge and regulatory charge at cost of service, and recovers the remainder of costs in the customer charge and electric delivery charge. Costs included in the community benefit charge, regulatory charge, and electric delivery charge, and costs not recovered in the $6 a month in customer charge are currently recovered in the energy charge. This results in lower electric bills for very low users and high users and higher electric bills for average users compared to Option A.

300 kWh Energy in Basic Monthly Charge with 4 Tiers (Option D) – This scenario applies a $30 basic monthly charge to include costs associated with the first 300 kWh of energy, applies the community benefit charge and regulatory charge at cost of service, and recovers the remainder of costs in the energy charge under a four-tier inclining block rate structure after the first 300 kWh of usage. This results in lower electric bills for low users, similar electric bills for average users, and slightly higher bills for some high users compared to Option A.

Table 6.5
Residential Rate Options and Estimated Prices

Residential Rate Options (summer season only)	Existing Rate	Cost of Service	Option Supported by Rate Analysis & Recommendation Report	Staff Options		
			Option A	Option B	Option C	Option D
Customer Charge ($/month)	$6.00	$21.69	$15.00	$10.00	$10.00	$30.00
Electric Delivery ($/month)	Inc. Below	$14.13	$10.00	$10.00	$6.24	N/A
Energy Charge (¢/kWh) – *Summer Period (June-Sept)*						
< 500 kWh *(32% of bills)*	6.948 ¢	7.504 ¢	5.514 ¢	5.514 ¢	6.948 ¢	0-300 (cust. charge)
501 – 1000 kWh *(33% of bills)*	11.218 ¢	7.504 ¢	9.514 ¢	9.514 ¢	11.218 ¢	300-1000 @ 10.000 ¢
1001 - 1500 kWh *(18% of bills)*	11.218 ¢	7.504 ¢	12.014 ¢	13.503 ¢	11.218 ¢	12.188 ¢
1501 – 2500 kWh *(13% of bills)*	11.218 ¢	7.504 ¢	13.514 ¢	16.003 ¢	11.218 ¢	13.712 ¢
> 2500 kWh *(5% of bills)*	11.218 ¢	7.504 ¢	14.514 ¢	17.503 ¢	11.218 ¢	14.728 ¢
Energy Adjustment (¢/kWh)	Inc. Above	-	-	-	-	-
Community Benefit (¢/kWh)		See below	See below	See below	See below	See below
Customer Assistance Program	Inc. Above	0.065 ¢	0.065 ¢	0.065 ¢	0.065 ¢	0.065 ¢
Service Area Street Lighting	Inc. Above	0.114 ¢	0.114 ¢	0.114 ¢	0.114 ¢	0.114 ¢
Energy Efficiency Charge	Inc. Above	0.301 ¢	0.301 ¢	0.301 ¢	0.301 ¢	0.301 ¢
Regulatory Charge (¢/kWh)	0.082 ¢	0.729 ¢	0.729 ¢	0.729 ¢	0.729 ¢	0.729 ¢
Average Monthly Bill at Usage Shown						
300 kWh Avg Annual Electric Bill	$26.84	$60.89	$42.96	$37.96	$40.71	$33.63
1000 kWh Avg Annual Electric Bill	$92.33	$119.39	$102.21	$97.21	$113.16	$102.76
2500 kWh Avg Annual Electric Bill	$247.10	$244.74	$289.53	$312.55	$281.57	$292.54
Monthly Dollar Difference from Current Rates						
300 kWh Avg Annual Electric Bill		$34.05	$16.12	$11.12	$13.87	$6.78
1000 kWh Avg Annual Electric Bill		$27.06	$9.88	$4.88	$20.83	$10.43
2500 kWh Avg Annual Electric Bill		($2.36)	$42.43	$65.45	$34.47	$45.44
Percent Change from Current Rates						
300 kWh Avg Annual Electric Bill		127%	60%	41%	52%	25%
1000 kWh Avg Annual Electric Bill		29%	11%	5%	23%	11%
2500 kWh Avg Annual Electric Bill		-1%	17%	27%	14%	18%

Table 6.6
Evaluation Matrix for Residential Rate Options

		Option Supported by Rate Analysis & Recommendation Report	Staff Options		
Rate Review Objectives and Policy Metrics	**Cost of Service**	**Option A Achieve Rate Review Objectives**	**Option B Shift Greater Fixed Costs to Energy Charge**	**Option C Current Energy Rates with New Fixed Charges**	**Option D 300 kWh Energy in Basic Monthly Charge & 4 Tiers**
Achieves Revenue Stability	Collecting all fixed costs in customer charge reduces revenue uncertainty due to economic volatility. Rate stabilization reserve established.	Improves fixed cost recovery and reduces revenue uncertainty. Rate stabilization reserve established.	Improves fixed cost recovery and reduces revenue uncertainty. Rate stabilization reserve established.	Improves fixed cost recovery and reduces revenue uncertainty. Rate stabilization reserve established.	Improves fixed cost recovery and reduces revenue uncertainty. Rate stabilization reserve established.
Ensures Long-Term Financial Strength	Meets revenue requirements.	Meets revenue requirements.	Meets revenue requirements.	Meets revenue requirements.	Meets revenue requirements.
Improves Fixed Cost Recovery	100%	70%	56%	45%	84%
Promotes Energy Efficiency & Distributed Solar	Weak incentive.	Strong incentive.	Strong incentive.	Weak incentive.	Strong incentive.
Minimize inter-class subsidies vs. cost of service study	Achieves cost of service and eliminates all inter-class subsidies.	All rate classes within 5% of cost of service goal.	All rate classes within 5% of cost of service goal.	All rate classes within 5% of cost of service goal.	All rate classes within 5% of cost of service goal.
Minimize intra-class subsidies vs. cost of service study	No subsidy. All usage tiers at cost of service.	Intra-class subsidy at mid-level.	Highest intra-class subsidy.	Lowest intra-class subsidy.	Intra-class subsidy at mid-level.
Provides Rates Simplicity	Similar to 1994 structure.	Introduces multiple tiers.	Introduces multiple tiers.	Similar to 1994 structure.	Introduces multiple tiers.
Customer Assistance Program funding.	Improves.	Improves.	Improves.	Improves.	Improves.

Proposed Residential Rate Alternatives

Rate alternatives for residential customers proposed by AE in this rate review include the continuation of a renewable pricing option that allows customers to receive 100 percent renewable energy (with some revisions to the program structure), a net metering rate that supports customer adoption of solar PV systems, and the implementation of a TOU rate intended to help customers and the utility save money if they lower their demand during peak time periods (when energy costs are higher) or shifting their demand from on-peak (when energy costs are higher) to off-peak periods (when energy costs are lower).

GreenChoice® Renewable Energy Alternative Rate

Austin Energy's GreenChoice program is the nation's most successful utility-sponsored, voluntary renewable energy pricing program, based on aggregate sales. Austin Energy residential customers can currently receive 100 percent renewable energy by enrolling in the utility's GreenChoice program and paying a renewable energy rate in lieu of the fuel adjustment clause. The GreenChoice rate represents the actual contract cost, estimated congestion costs, and administrative costs for renewable energy purchased by AE. Customers currently participate in the GreenChoice program by subscribing to a specific "batch" that locks-in the renewable energy rate for the length of the contract (typically around 10 years). To date, six batches have been developed and the first two batches expired in March 2011. Austin Energy is proposing improvements to the structure of its GreenChoice program with the objective of remaining a leader in renewable energy sales and meeting customer demand.

Residential customers currently subscribed to GreenChoice will continue to receive their locked-in renewable energy rate and fuel costs embedded in the proposed energy charge will be removed from their electric bills. Additionally, current GreenChoice customers will not have any fuel portion of future energy adjustments applied to their bills during the term of their contract. In other words, current GreenChoice customers will see no change on their bill with regard to fuel costs even after new rates are implemented until the GreenChoice batch they are subscribed to expires. The application of all non-fuel-related charges will be the same for GreenChoice customers as with other customers. As existing GreenChoice customer contracts expire, customers will have the option to subscribe to the new adopted GreenChoice rate or the adopted standard residential rate.

The proposed new GreenChoice program structure will continue to allow customers to lock-in a fixed price for receiving 100 percent renewable energy in lieu of the fuel charges embedded in the energy charge and any future energy adjustments over the term period established for each annual offering. All other charges are applicable in the same manner as with other residential customers. The primary GreenChoice program design change proposed by AE is a move from a "batch" pricing approach in which the offered price is tied to a specific renewable resource contract to a portfolio-based pricing approach in which renewable energy is added to the GreenChoice portfolio inventory to determine the GreenChoice price. This will allow AE to develop annual price offerings for GreenChoice based on the utility's entire renewable resource portfolio as the utility pursues its renewable generation goals on a system-wide basis. This will increase the utility's flexibility in developing the GreenChoice offer price. This GreenChoice price as well as the adjustment which will be applied to customer electric bills will be calculated annually. The current proposal envisions sales under the new program to begin April 1, 2012, and January 1 each year thereafter. Therefore, GreenChoice will be subscribed to on the basis of individual annual offerings and identified in terms of year; for example, GC2012 for subscriptions based on the offering in 2012, GC2013 for 2013, and so on.

An additional change to the GreenChoice pricing structure is that GreenChoice subscribers will now receive credit for the amount of un-subscribed renewable energy that is shared among all customers. As with the current program structure, if the program is not fully subscribed the costs of unsold renewable energy secured by Austin Energy will be spread among all other customers. For example, if 90 percent of the renewable energy allocated to the program is subscribed under GreenChoice, 10 percent of the costs must be passed on to all other customers. Therefore, all other customers will receive a certain portion of their electricity from renewable resources. Since GreenChoice subscribers could have received a percentage of their energy from renewable resources regardless of their participation in GreenChoice, AE is proposing that GreenChoice customers receive a credit for the amount of renewable energy they would have received under the standard residential electric rate.

Consistent with current practice, the GreenChoice price consists of components that will be fixed during the length of term established and tied to each annual product offering. The fixed GreenChoice price is based on two components: (1) cost of the renewable supply, including transmission and delivery costs, and any applicable ERCOT charges; and (2) administrative, marketing, and general revenue costs associated with the program. This price will not change during the life of the subscription. However, given that fuel charges are now embedded in the energy rate, treatment of GreenChoice subscribers from a billing standpoint is somewhat different from current practice. Subscriber bills will be subject to a "GreenChoice Adjustment" which is the result of a calculation that takes into account: (1) the fixed GreenChoice price, (2) subtraction of any charges related to fuel, and (3) proration to exclude any system renewable energy not allocated to other GreenChoice subscribers. The GreenChoice adjustment is calculated based on the following formula:

GreenChoice Adjustment = GreenChoice Price – Fuel Charges * SRS Adjustment (see below)

Where GreenChoice Price is the fixed charge established at the time of subscription, *Fuel Charges* are any costs associated with fuel used in non-renewable electricity production, and the *SRS Adjustment Factor* (explained below) is a percentage (0%-100%) which takes into account the difference between System Renewable Energy as described below and energy allocated to GreenChoice subscriptions.

The System Renewable Supply Adjustment Factor ("SRS") is expressed as a percentage and is defined as 100 minus the difference between *Community Supply* and *GreenChoice Supply*.

Community Supply ("CS") is defined as any energy produced from all renewable energy sources which are owned and operated by AE and/or interconnected to the AE electric distribution system and metered, including customer-owned generation, city-owned generation, AE-owned generation not allocated to the GreenChoice program, and renewable energy associated with GreenChoice subscriptions. Community Supply is expressed as a percentage of total retail sales to AE customers and calculated on an annual basis.

GreenChoice Supply (GS) is defined as energy attributable to GreenChoice customer subscriptions, including subscriptions initiated before April 1, 2012, expressed as a percentage of total retail sales to AE customers and calculated on an annual basis.

The formula for determining the GreenChoice adjustment on a monthly basis, including the SRS adjustment is as follows:

GreenChoice Price	GCP_1	(¢/kWh)
Fuel Charges	FC	(¢/kWh)
Subtotal (GCP_1-FC)	GCP_2	(¢/kWh)

SRS% = 100% – [Community Supply (CS) % - GreenChoice Supply (GS) %]

GreenChoice Adjustment (¢/kWh) = (GCP_2 X SRS) x Monthly Consumption (kWh)

The GreenChoice adjustment may change on an annual basis as any fuel-related adjustments are incurred or there are changes in either Community Supply or GreenChoice Supply, but customers should note the fixed cost established at the time of their subscription will remain so for their term.

An example of the GreenChoice adjustment calculation is provided as Table 6.7 for a hypothetical residential customer using 1,000 kWh per month. Please note that the numbers assumed in this example are for illustrative purposes only as actual numbers may vary from this example.

Table 6.7
Hypothetical Proposed GreenChoice® Calculation under Proposed Rates for Residential Customer Consuming 1,000 kWh per Month

GreenChoice® Price	GCP_1	= 20.0 ¢/kWh
Fuel Charges	FC	= 10.0 ¢/kWh
Subtotal (GCP_1 – FC)	GCP_2	= 20.0 ¢/kWh – 10.0 ¢/kWh
		= 10.0 ¢/kWh
System Green Power Produced/Purchased = 10,000,000 MWh/Year		
Green Power Subscribed = 5,000,000 MWh/Year		
Total Energy Produced/Purchased = 100,000,000 MWh/Year		
Community Supply (CS)		= 10,000,000 MWh / 100,000,000 MWh
		= 10%
GreenChoice® Supply (GS)		= 5,000,000 MWh/100,000,000 MWh
		= 5%
SRS Adjustment		= 100% – [10% – 5%]
		= 100% – 5%
		= 95%
GreenChoice® Adjustment		= (10 ¢/kWh * 95%) * 1,000 kWh
		= $95

Net Metering Distributed Generation Alternative Rate

Residential customers can also currently receive credit on their electric bill for producing electricity from distributed generation systems such as solar PV by participating in the utility's net metering rate. Austin Energy is making one substantive change to its net metering rate by proposing to apply a credit at a determined value of solar amount for any excess energy generated on a monthly basis rather than crediting excess generation at the utility's fuel rate. It is the utility's intention to continue to evaluate other options for pricing solar PV to support the utility's strategic objectives of supporting 200 MW of solar by 2020. The utility intends to move to a separate solar rate when meter data management capabilities are achieved.

The net metering rate option is designed for residential customers who have installed a solar PV system or other renewable distributed generation system at their residence for up to 20 kW of production that is interconnected with AE's electric system. This rate is designed to fairly compensate these customers for their generation of emissions-free, local, grid-tied electricity while still charging the customers for the electricity they consume. Net metering is designed to charge a customer for their monthly net energy consumption (i.e., total energy taken from the grid less any energy provided back to the grid). If a customer provides more energy back to AE than it consumes from the grid in a given month, the customer is currently credited at AE's existing fuel rate. Under the proposed new net metering rate, the same net metering calculation will apply, but the customer will receive credit for the excess electricity produced (over consumption for any month) at a calculated annual value of solar rate.

The credit provided to a residential solar customer's monthly electric bill is calculated using a value of solar algorithm developed in 2006 in a study commissioned by the utility and updated annually. This calculation takes into consideration the value of the energy produced based upon the marginal costs of the displaced energy, the avoided capital cost of installing new power generation due to the added capacity of the solar PV system, transmission and distribution expense and line loss savings associated with the system, and environmental benefits. The credit would be adjusted annually to account for market value changes and other factors that influence the value of the solar energy generated. As shown in Table 6.8, from 2006 through 2011 the value of solar has fluctuated from 9.9 cents per kWh to 16.4 cents per kWh dependent on the type of system installed (i.e., fixed versus tracking system). In 2011, this algorithm resulted in a 12.6 cents per kWh value for solar.

Table 6.8
Value of Solar By Year

Year	System Type	Average Value (cents/kWh)
2006	Fixed	10.3
2007	Fixed	11.8
2008	Fixed	16.4
2009	Fixed	13.8
2011	Fixed	12.6
2006	Track	9.9
2007	Track	11.4
2008	Track	15.8
2009	Track	14.1
2011	Track	12.8

Time-of-Use Alternative Rate

A time-of-use ("TOU") alternative rate is being proposed to gauge customer interest in receiving pricing signals that reflect electric market prices at different periods of the day with the objective of saving the utility and the customer money if changes in consumption patterns are made. As a TOU rate is based on calculations that necessarily reflect a number of assumptions and preliminary estimates, AE is initially offering this alternative rate to a limited number of participants with an initial enrollment cap of 2,000 customers. Once more research and information is gathered, AE will consider expansion or modification of the TOU alternative rate.

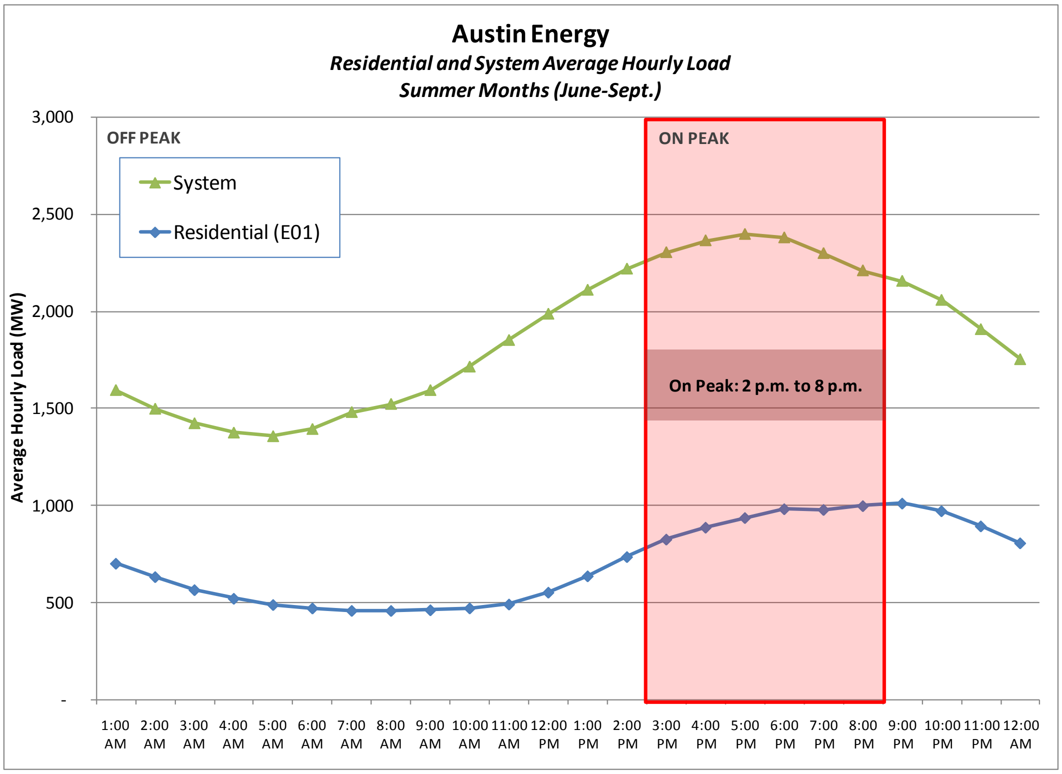
Under a TOU rate structure, customers pay higher prices during peak periods to reflect cost variances over the day and create an incentive for peak demand reduction through energy conservation and/or the shifting of usage from on-peak periods when electricity is more costly to less costly off-peak periods. The TOU alternative rate is designed to better reflect variations in AE's power costs (seasonally and at various times of the day). If successful, the TOU rate design will incentivize residential customers to reduce their coincident peak demand on the AE system and to realize cost savings from changing their electricity usage pattern. Reducing peak demand can help the utility counteract the need to build costly new power plants or buy costly market power by reducing load during periods of high demand when power market prices are highest. This helps lower the utility's overall costs and these cost savings can potentially be transferred on to all customers.

To develop cost of service-based TOU rates, AE's TY power production costs were reviewed in detail using AE's RTSIM and UPLAN production cost modeling software. RTSIM dispatches generation resources to load and is not concerned with ERCOT market transactions. UPLAN dispatches generation resources to the ERCOT market and reflects market transactions. The RTSIM analysis renders time differentiated generation costs at different times of the day and year. These costs are aligned with AE system load shape. This information is helpful in determining pricing signals in various time of use periods. From RTSIM output, hourly production costs by resource were determined and these operating costs were separated into base demand-related costs, intermediate demand-related costs, and peak demand-related costs. Unit costs for peak demand, intermediate demand, and base demand power generating units for both summer and non-summer rate periods were also calculated.

Although similar, the dispatch of generation resources using UPLAN was more variable than under RTSIM. This variability is associated with market purchases and sales. Therefore, for rate design purposes, RTSIM was relied upon for TOU rate design. RTSIM is reflective of the cost of AE generation dispatch to load. This linkage between generation resources and system load improve the definition of power generation costs during different time periods. Over time, given a static power generation portfolio, generation costs in different time periods will be less volatile in RTSIM than in UPLAN. Since AE desires to provide its customers with stable time of use pricing, RTSIM was relied upon for costing information.

The analysis of AE's RTSIM production data indicated that the four-month period from June through September required significant use of peaking power generating units, particularly natural gas turbines, to meet AE's peak demand requirements. In addition, the data supported the identification of a Monday through Friday 2 p.m. to 8 p.m. summer peak-demand time period as well as an off-peak demand time period from 10 p.m. to 6 a.m. daily. Figure 6.4 shows AE's hourly system demand compared to hourly demand for the Residential customer class on a typical peak summer day.

Figure 6.4
Residential Hourly Load – Summer



Time-of-use-based demand charges for peak, intermediate, and baseload functions were determined using the allocated demand-related production costs for each customer class from the cost of service analysis. On-peak, intermediate peak, and off-peak demand related-costs were calculated by dividing these production costs by customer class billed demand and energy estimates determined using AE's load research data for on-peak, intermediate-peak, and off-peak time periods. The summer on-peak demand and energy charges represent the summation of all three of these unit costs. The non-summer intermediate peak energy charge represents the summation of the intermediate-peak and off-peak unit costs for each customer class.

Under this methodology, all demand-related costs are recovered through a monthly on-peak demand and energy charge during the summer months and a monthly intermediate-peak energy charge during the non-summer months. Under this rate structure, there would be no charge for customer demand during the off-peak period as this is intended to create an incentive for customers to shift their electricity usage to off-peak periods.

This rate is being developed in part to encourage customers with electric vehicles to primarily recharge those vehicles during off-peak hours, such as overnight, and may be provided to electric vehicle hours for charging usage only or for their entire residential usage. This TOU rate is the first of several pricing pilots that will be developed for residential customers over the next several years. These pricing pilots are intended to leverage the utility's investment in advanced metering and a new customer billing system with the objective of developing new rate structures that achieve cost savings for both customers and the utility.

Information on residential demand and energy unit costs were used in conjunction with the residential billing data for the TY to calculate potential unadjusted residential production cost recovery revenues. This was then compared with the Residential customer class total production function revenue requirement. Based on this analysis, minor adjustments to the demand and energy charges were made along with the estimation of a 5 percent demand response for TOU charged residential usage to account for price elasticity. Therefore, residential TY TOU billing units charged at the TOU rates exactly equal the residential class revenue requirement.

The proposed residential TOU structure is summarized in Table 6.9. The residential TOU rate was designed to complement the proposed residential five-tier including block rate structure. As a result, the rate is more complex that traditional TOU rate structures. The structure is intended to preserve the conservation and energy efficiency pricing signal provided under the standard residential rate while offering customers a lower rate for off-peak usage. Table 6.10 provides an example of a residential customer with summer monthly average consumption of 1,400 kWh.

Table 6.9
Residential Customer Class – Proposed Time-of-Use Alternative Rate

Name of Charge/Rate	Non-Summer Rate Period (October-May)	Summer Rate Period (June-September)
Customer Charge ($/month)	18.00	18.00
Electric Delivery Charge ($/month)	10.00	10.00
Energy Charge (¢/kWh) (1)		
On-Peak Hours (Summer 3-9 p.m. only)		
< 500 kWh	n/a	10.500
501-1000 kWh	n/a	11.750
1001-1500 kWh	n/a	12.764
1501-2500 kWh	n/a	13.500
>2500 kWh	n/a	17.500
Mid-Peak Hours		
< 500 kWh	3.200	7.500
501-1000 kWh	4.892	8.685
1001-1500 kWh	7.100	9.500
1501-2500 kWh	8.536	10.000
>2500 kWh	12.000	12.000
Off-Peak Hours		
< 500 kWh	2.200	3.800
501-1000 kWh	2.700	4.500
1001-1500 kWh	3.290	5.500
1501-2500 kWh	4.000	6.000
>2500 kWh	7.500	9.500
Energy Adjustment (¢/kWh) (1)	n/a	0.00
Community Benefit Charge (¢/kWh) (2)		
Customer Assistance Program (¢/kWh)	0.065	0.065
Service Area Street Lighting (¢/kWh)	0.114	0.114
Energy Efficiency Charge (¢/kWh)	0.301	0.301
Transmission Service Adjustment Rider (¢/kWh) (3)	n/a	n/a
Regulatory Charge (¢/kWh) (4)	0.729	0.729

Notes:
1. The Energy Adjustment is a new charge that replaces the current Fuel Adjustment Clause. The Energy Adjustment is set to zero but is subject to change as described in Section 5 of this report.
2. The Community Benefit Charge is a new charge that funds three specific programs and services provided to the community by AE. The Customer Assistance Program administers funds to provide discounts to qualified low-income customers or other disadvantaged customers. Service Area Lighting recovers the cost of street lighting to customers within the entire AE service territory. Energy efficiency recovers the cost of energy efficiency, green building, and solar rebate programs offered by AE.
3. The Transmission Service Adjustment is a current charge associated with AE's cost of ERCOT transmission. This adjustment would be discontinued under the proposed rate structure and these costs would be included in the new Regulatory Charge.
4. The Regulatory Charge is a new charge that replaces the TSAR and includes ERCOT administration fees and charges associated with AE's cost of ERCOT transmission.

Table 6.10
Applicable TOU Alternative Rate Example (Summer Season 1,400 kWh)

Name of Charge/Rate	Charge/Rate
Customer Charge ($/month)	18.00
Electric Delivery Charge ($/month)	10.00
Energy Charge (¢/kWh)	
Summer Season (June - September)	
On-Peak	12.764
Mid-Peak	9.5000
Off-Peak	5.5000
Energy Adjustment (¢/kWh) (1)	0.00
Community Benefit Charge (¢/kWh) (2)	
Customer Assistance Program (¢/kWh)	0.065
Service Area Street Lighting (¢/kWh)	0.114
Energy Efficiency Charge (¢/kWh)	0.301
Regulatory Charge (¢/kWh) (3)	0.749

Notes:
1. The Energy Adjustment is a new charge that replaces the current Fuel Adjustment Clause. The Energy Adjustment is set to zero but is subject to change as described in Section 5 of this report.
2. The Community Benefit Charge is a new charge that funds three specific programs and services provided to the community by AE. The Customer Assistance Program administers funds to provide discounts to qualified low-income customers or other disadvantaged customers. Service Area Lighting recovers the cost of street lighting to customers within the entire AE service territory. Energy efficiency recovers the cost of energy efficiency, green building, and solar rebate programs offered by AE.
3. The Regulatory Charge is a new charge that replaces the TSAR and includes ERCOT administration fees and charges associated with AE's cost of ERCOT transmission.

Customers who use a larger amount of energy during off-peak periods that on-peak periods would be rewarded under this rate structure with a lower monthly electric bill. However, customers with on-peak power usage would typically pay more compared to the standard rate as shown in Table 6.10.

Table 6.11
Residential Bill Comparison (Summer Season 1,400 kWh)

Applicable Residential Rate	Monthly Power Bill - Summer Season	Percent Difference in Bill
Standard Rate	$165.79	n/a
TOU Rate – On-Peak Usage (1)	$174.86	5.5%
TOU Rate – Off-Peak Usage (2)	$150.23	-9.4%

Notes:
1. On-Peak Usage Assumptions (% of total monthly energy consumed): 28% Off Peak, 49% Mid Peak and 23% On Peak.
2. Off-Peak Usage Assumptions (% of total monthly energy consumed): 52% Off Peak, 45% Mid Peak and 3% On Peak.

Long-Term Objectives for Residential Pricing

The proposed residential rate, residential rate options, and rate alternatives were designed to address the current needs of customers. Austin Energy is unbundling rates and beginning to experiment with TOU rates as an initial step towards a technology-enabled future where customers are given strong pricing signals to adjust their electricity usage in real-time. The realization of this goal requires infrastructure investment as well as consumer adoption of certain technologies and products.

Austin Energy has invested in an advanced metering infrastructure, or smart grid system, that now serves all of its customers allowing for greater system control. This also enables new electricity pricing models to be developed and new opportunities for customer management of energy use if customers adopt certain technologies on their side of the meter. Austin Energy can leverage its investments in the smart grid as well as a new customer billing system by offering rate structures that provide customers with improved price signals and more electricity usage data.

One major risk in moving towards innovative rate design is that rate structures such as real-time pricing tend to reduce overall system load growth and increase volatility of the revenue stream, impacting the financial strength of the utility. Another major risk is potential unintended financial consequences on those with fixed or low incomes. These impacts, if not well thought-out and appropriately phased-in, could present undue hardship to many customers who are not prepared for major changes in rate structures and customer-utility interaction.

For these reasons, AE has a long-term residential pricing strategy that considers the principle of gradualism with change taking place incrementally over time so that risks to AE and its customers are minimized. Affordability for all customers can best be achieved by phasing in new rate structure changes and providing a diversity of options that improve customer ability to manage their electricity usage.

Pecan Street Project Pricing Pilots

Following this rate review and in coordination with Pecan Street Project Inc., AE will be conducting pilot projects on a variety of residential pricing structures. Pecan Street Project's research team will work exclusively with volunteer participants. The pricing studies will help AE and the Pecan Street Project research team evaluate the effectiveness of different pricing models. Austin Energy and the Pecan Street Project will evaluate the impact of various pricing models on customer satisfaction, peak demand, customer bills, utility finances, environmental impact, and promotion of private sector product and service development. The pilots will begin with an initial phase trial in the spring of 2012, followed by deployment of multiple models in parallel later that year.

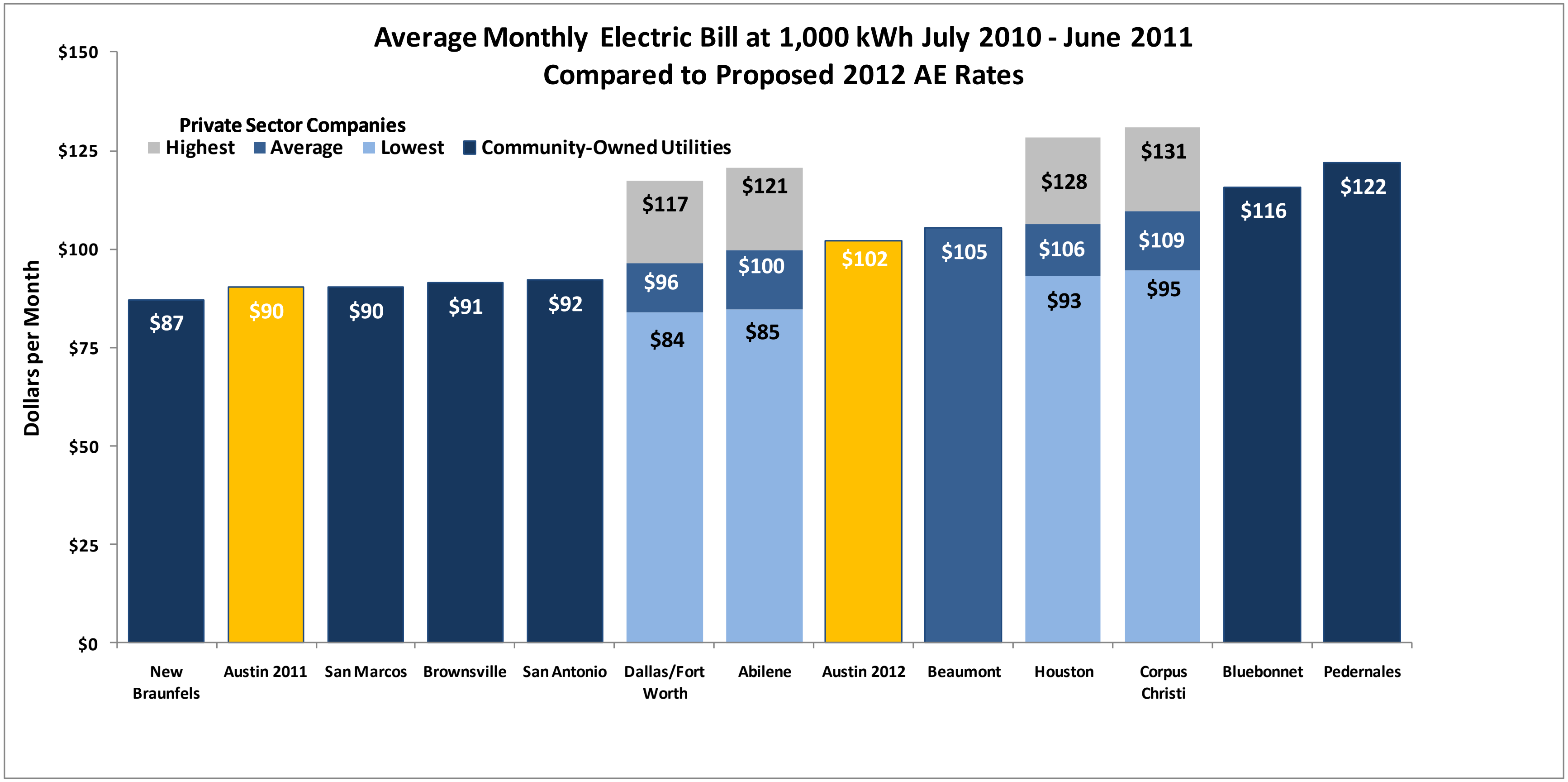
Residential Rate Benchmarking

Austin Energy is committed to maintaining the affordability of electricity in the community and has established goals to keep customer electric bills low and comparable to other customers around the state. On February 17, 2011, the City Council approved the utility's Resource Plan including an affordability goal. The affordability goal requires that AE operate so as to control rate (base, fuel, riders, etc.) increases to residential, commercial, and industrial customers to 2 percent or less per year. In addition, the goal is to maintain AE's current all-in competitive rates in the lower 50 percent of Texas rates. The affordability goal will be effective upon implementation of AE's new rates following this rate review.

Specifically for this rate review, AE has established goals for mitigating the impact of rate increases within customer classes by designing rates that prevent residential customer electric bills below 1,500 kWh from increasing by more than $20 a month on average and transitioning Secondary Voltage commercial customers currently not being assessed demand rates to demand rates. Increasing funding to the Customer Assistance Program will also help the most disadvantaged customers served by AE continue to afford electricity.

Austin Energy completed its first comprehensive electric rate benchmarking study in November 2010 and concluded that AE's electric rates, particularly average electric bills, have been comparable to, and at times lower than, other utilities and electric service providers in Texas. Results from that study have been updated to show the most current 12-month period of benchmarking data (July 2010 through June 2011) available to compare with AE's proposed rates . Figure 6.5 demonstrates an average monthly residential bill at the 1,000 kWh usage level for selected comparable utilities in Texas. Results for community-owned, or public power, utilities are based on the current applicable tariff while results for the private sector companies are based on an analysis of pricing offers in the competitive markets in Texas. It should be noted that the results for the private sector companies therefore represent an estimate of the price a customer could have paid over the time period of the analysis rather than what was actually paid. The Energy Information Administration data provided below shows actual reported average residential rates for retail electric service providers in the competitive markets.

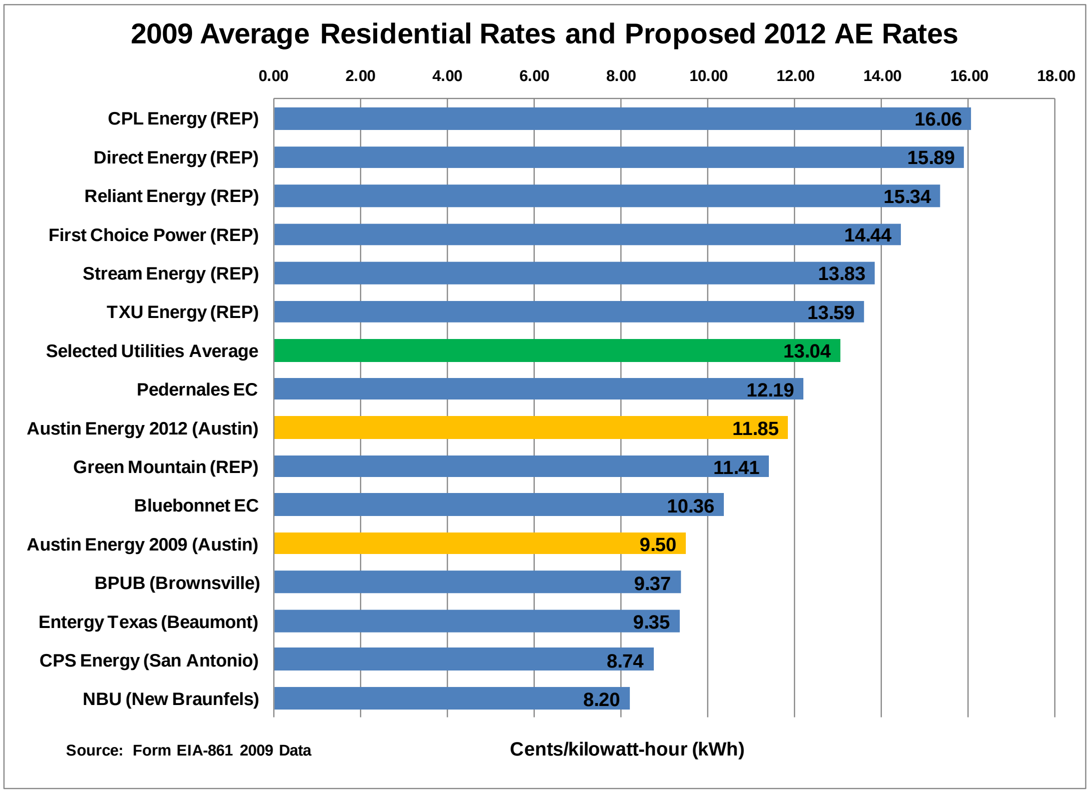
Figure 6.5
Average Monthly Residential Electric Bill at 1,000 kWh July 2010 – June 2011 Compared to Proposed 2012 AE Residential Rate Option Supported by Report



Under AE's current residential rate, an AE residential customer using 1,000 kWh of electricity each month would pay $90 per month on average over a 12-month period, compared to a CPS Energy (San Antonio) customer who would have paid $92 per month on average or a Pedernales Electric Cooperative customer who would have paid $122 per month on average for 1,000 kWh of usage from the period of July 2010 through June 2011. With adjusted TY fuel (which would occur regardless of a base electric rate increase), the average electricity bill for a 12-month period for residential customers would be about $98 per month. Under AE's proposed residential rates, which includes TY fuel, a residential customer using 1,000 kWh of electricity each month would pay $102 per month on average making AE's proposed residential rate at 1,000 kWh similar to average pricing offers in the competitive markets in which private sector companies provide electric service.

Figure 6.6 shows an average residential rate comparison between AE and other major electric service providers in Texas for 2009 based upon data from the U.S. Energy Information Administration (EIA-861 data). This data shows that in 2009 (the last year for which results are currently available and the same year as AE's cost of service study) AE's average residential rates were among the lowest in Texas and even under the proposed new rates AE's average remains lower than the average of the selected comparable utilities.

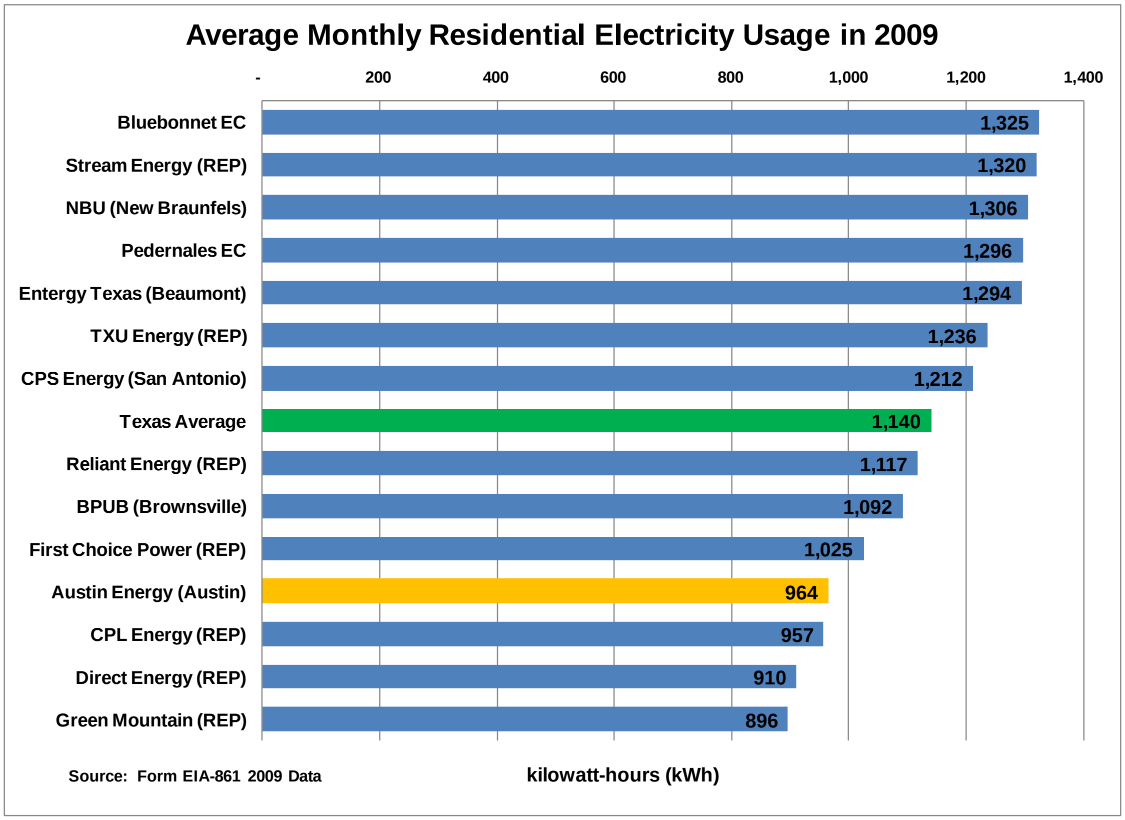
Figure 6.6
Average Residential Rates in Texas – 2009 Compared to Proposed 2012 AE Residential Rate Option Supported by Report



Source: EIA Form 861 – 2009, www.eia.doe.gov/cneaf/electricity/page/eia861.html, except for Austin Energy 2012.

Another factor that should be considered when evaluating the affordability of electricity is average consumption levels. Affordability is measured based on the actual electric bill cost, not simply based on the rates at which electricity is priced. For a utility like AE, which has promoted energy conservation and invested millions of dollars in energy efficiency, electricity bills will be lower than many otherwise comparable utilities due to improved home and building efficiency and energy conservation behaviors. Figure 6.7 compares average residential energy consumption for customers served by major electric service providers in Texas. In 2009, AE residential customers used over 20 percent less energy than residents of CPS Energy in San Antonio, a utility of somewhat comparable size with similar weather conditions. Usage was as high as 37 percent greater for Bluebonnet Electric Cooperative residential customers than AE residents, a utility with a service territory in close proximity to Austin.

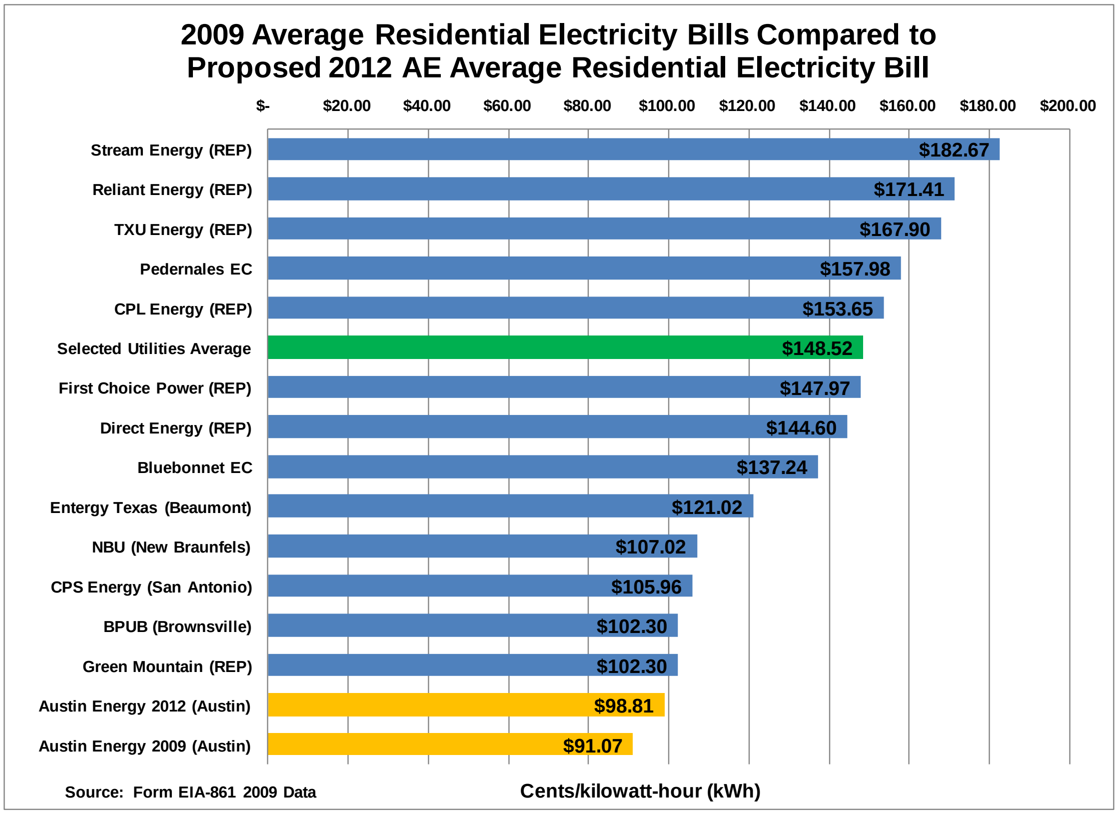
Figure 6.7
Average Residential Energy Consumption in Texas – 2009



Source: EIA Form 861 – 2009, www.eia.doe.gov/cneaf/electricity/page/eia861.html.

The EIA-861 data for average residential consumption and average residential rates can be used to calculate an average residential electric bill. These results, presented in Figure 6.8, show that average residential electric bills are considerably lower in AE than average residential electric bills in other areas of Texas. In 2009 an average residential AE customer using 964 kWh would have had an average electric bill of about $91 a month. Under AE's proposed rates, electric bills at 964 kWh per month would be about $99 a month on average. This compares to an average electric bill in selected utilities of over $148 a month in 2009. The results for this analysis for AE 2012 rates are dependent upon the new residential rate structure adopted. Each optional scenario developed by AE would have a slightly different result.

Figure 6.8
Average Residential Electric Bill in Texas – 2009 Compared to AE Staff Recommendation (Option A)



Source: EIA Form 861 – 2009, www.eia.doe.gov/cneaf/electricity/page/eia861.html, except for Austin Energy 2012.

Section 7
COMMERCIAL AND INDUSTRIAL RATE DESIGN

This section provides analysis in support of the proposed rates for AE's redesigned commercial and industrial customer classes. This includes all non-residential and non-lighting customers. The proposed rates are presented first, followed by an analysis of customer bill impacts. Since many commercial and industrial customers are moving into new customer classes, bill impact analysis is provided for each existing customer class that will have all or a portion of the customers placed in each proposed customer class. The proposed customer classes are described in detail in Section 2 of this report. The proposed consolidation of customer classes is designed to ensure that fair and equitable rates are created for all customer types. Customers are placed into their class based on the voltage level at which they receive power and their level of demand on the system as these are the two most significant drivers of cost for customer classes.

Commercial and Industrial Rate Design Objectives

The commercial and industrial rate structures proposed by AE are designed to meet the following objectives which align with AE's rate design principles described in Section 5 of this report:

- To the extent possible, move revenues generated from rates closer to the cost of service for the commercial and industrial customer classes, thereby minimizing or eliminating inter-class subsidies.
- Improve fixed cost recovery, thereby minimizing intra-class subsidies, particularly between the low load factor and high load factor electricity users within the commercial and industrial customer classes.
- Create a rate structure that is stable yet flexible to ensure the relevance of the rate structure into the foreseeable future and allow the utility to achieve its long-term commercial and industrial pricing objectives.
- Improve pricing signals that encourage conservation and promote energy efficiency improvements.
- Improve pricing transparency and develop rate structures that are practical and understandable to customers.
- Offer rate options that support customer behavior and technology adoption that is beneficial to the environment and the utility system, including rates that support renewable energy, solar PV, and thermal energy storage technologies, and promotion of shifting electricity usage from on-peak periods (which represent periods of higher system cost) to off-peak periods (representing periods of lower system cost).

- Protect the utility from uncontrollable events or circumstances by maintaining and establishing pass-through charges associated with market transactions and regulatory costs, including fuel-related costs.

The cost of service study indicates that while fixed cost recovery is a significant challenge for the Residential customer class, the current misalignment of fixed costs and fixed revenue recovery is not as pronounced for AE's commercial and industrial customer classes. Austin Energy is proposing a more equitable fixed cost recovery structure by removing customer service and distribution costs currently recovered in the demand charge and applying a customer charge and electric delivery charge for all commercial and industrial customers.

Currently, commercial and industrial customers with a peak demand of over 20 kW are assessed a demand charge (in kW), which is a charge specifically designed to collect fixed costs. A demand charge reflects the way in which certain costs are incurred and provides an incentive for customers to reduce their demand by making energy efficiency improvements or controlling the maximum demand they place on the system. Currently, small commercial customers with a peak demand of less than 20 kW do not pay a demand charge. Austin Energy is proposing that these small commercial customers be charged for demand under the new rate design. Charging all commercial and industrial customers a demand charge will improve fixed cost recovery from this customer segment and provide a pricing signal for energy efficiency and conservation to all customers. Austin Energy currently has almost 35,000 non-demand commercial customers. Austin Energy is proposing that current non-demand customers receive transition rates designed to mitigate immediate rate impacts on these customers as they transition from a non-demand rate to a demand rate.

Current Rate Structure and Prices

Austin Energy's commercial and industrial customers are segmented into several customer classes to distinguish between service requirements (such as being served at the secondary, primary, or transmission connection voltage level) and variation in electricity usage characteristics (energy consumption pattern and level of demand on the system). This allows the utility to develop rates that are based on meaningful cost of service differences.

Currently, the only non-residential customers assessed a customer charge are worship facilities (because they are currently billed under the Residential rate) and commercial customers with demand less than 20 kW. As described in Section 2 of this report, worship facilities have service requirements and usage characteristics that are similar to commercial customers. AE intends to place worship facility customers in the applicable commercial rate class under the rate proposal described herein. Currently, all non-residential customers are assessed a demand charge except for worship facilities, commercial customers with demand less than 20 kW, water and wastewater facilities, and the City of Austin. As mentioned above, AE is proposing a transition to demand rates for these customers over a three year period of time.

Commercial and industrial rate structures currently include an energy charge and the fuel adjustment pass-through charge. The fuel adjustment charge directly passes fuel-related costs on to the customer. Another current pass-through charge is the TSAR which was implemented in October 2010 to recover incremental costs associated with new transmission build-out in Texas. The TSAR is applied to all customers except those exempted due to being under contract terms. For customers who purchase renewable energy through AE's GreenChoice program, the renewable energy rate is applied in lieu of the fuel adjustment charge.

Table 7.1 summarizes AE's existing commercial and industrial rate structure. Note that some current customer classes are based on building ownership such as state or school customers. Also, there are several rates designed for customers under a long-term contract rate. Contract customers are locked-in to their current rates through May 2015. Upon expiration of their contracts, it is AE's intention to either place these customers into their appropriate customer class at the then current rate approved for that customer class or to renegotiate their rates based cost of service.

Table 7.1
Commercial and Industrial Customers – Summary of Existing Rates

Item	Winter Rate Period (November - April)	Summer Rate Period (May - October)
Worship (EO1C)		
Customer Charge ($/month)	6.00	6.00
Energy Charge (¢/kWh)		
First 500 kWh	3.55	3.55
500 kWh or more	6.02	7.82
Demand Charge ($/kW)		
All kW	0.00	0.00
Pass-Through Charges (¢/kWh)		
Fuel Adjustment Charge (adjusted for TY)	3.398	3.398
Transmission Service Adjustment Rider (¢/kWh)	0.086	0.086
General Service Non-Demand (EO2)		
Customer Charge ($/month)	6.00	6.00
Energy Charge (¢/kWh)		
All kWh	4.64	6.44
Demand Charge($/kW)		
All kW	0.00	0.00
Pass-Through Charges (¢/kWh)		
Fuel Adjustment Charge (adjusted for TY)	3.398	3.398
Transmission Service Adjustment Rider (¢/kWh)	0.078	0.078
Water and Wastewater (EO3)		
Customer Charge ($/month)	0.00	0.00
Energy Charge (¢/kWh)		

Table 7.1
Commercial and Industrial Customers – Summary of Existing Rates

Item	Winter Rate Period (November - April)	Summer Rate Period (May - October)
All kWh	2.77	6.48
Demand Charge ($/kW)		
All kW	0.00	0.00
Pass-Through Charges		
Fuel Adjustment Charge (adjusted for TY) (¢/kWh)	3.398	3.398
Transmission Service Adjustment Rider (¢/kWh)	0.045	0.045
Other City (EO4)		
Customer Charge ($/month)	0.00	0.00
Energy Charge (¢/kWh)		
All kWh	3.54	5.21
Demand Charge ($/kW)		
All kW	0.00	0.00
Pass-Through Charges		
Fuel Adjustment Charge (adjusted for TY) (¢/kWh)	3.398	3.398
Transmission Service Adjustment Rider (¢/kWh)	0.063	0.063
General Service Demand (EO6)		
Customer Charge ($/month)	0.00	0.00
Energy Charge (¢/kWh)		
All kWh	1.80	1.80
Demand Charge ($/kW)		
All kW	12.65	14.03
Pass-Through Charges		
Fuel Adjustment Charge (adjusted for TY) (¢/kWh)	3.398	3.398
Transmission Service Adjustment Rider ($/kW)	0.26680	0.26680
Primary Service (E07)		
Customer Charge ($/month)	0.00	0.00
Energy Charge (¢/kWh)		
All kWh **(¢/kWh)**	1.51	1.51
Demand Charge ($/kW)		
All kW	11.11	12.10
Pass-Through Charges		
Fuel Adjustment Charge (adjusted for TY) (¢/kWh)	3.321	3.321
Transmission Service Adjustment Rider ($/kW)	0.24998	0.24998
State General Service Non-Demand (E13)		
Customer Charge ($/month)	6.00	6.00

Table 7.1
Commercial and Industrial Customers – Summary of Existing Rates

Item	Winter Rate Period (November - April)	Summer Rate Period (May - October)
Energy Charge (¢/kWh)		
All kWh	3.19	4.99
Demand Charge ($/kW)		
All kW	0.00	0.00
Pass-Through Charges		
Fuel Adjustment Charge (adjusted for TY) (¢/kWh)	3.398	3.398
Transmission Service Adjustment Rider ($/kWh)	0.00046	0.00046
State General Service Demand (E14)		
Customer Charge ($/month)	0.00	0.00
Energy Charge (¢/kWh)		
All kWh	1.07	1.07
Demand Charge ($/kW)		
All kW	10.94	11.64
Pass-Through Charges		
Fuel Adjustment Charge (adjusted for TY) (¢/kWh)	3.398	3.398
Transmission Service Adjustment Rider ($/kW)	0.26284	0. 26284
Independent School Districts (E23)		
Customer Charge ($/month)	0.00	0.00
Energy Charge (¢//kWh)		
On-Peak	2.47	2.72
Off-Peak	1.99	2.02
Demand Charge ($/kW)		
On-Peak	5.68	7.95
Off-Peak	0.00	0.00
Pass-Through Charges		
Fuel Adjustment Charge (adjusted for TY) (¢//kWh**)**	3.398	3.398
Transmission Service Adjustment Rider ($/kW)	0.20524	0.20524
Large Primary Special Contracts (LIR1S)		
Customer Charge ($/month)	0.00	0.00
Energy Charge (On-Peak) (¢/kWh)		
All kWh	1.08	1.08
Demand Charge (On-Peak) ($/kW)		
All kW	11.12	12.23
Pass-Through Charges		

Table 7.1
Commercial and Industrial Customers – Summary of Existing Rates

Item	Winter Rate Period (November - April)	Summer Rate Period (May - October)
Fuel Adjustment Charge (adjusted for TY) (¢/kWh)	3.321	3.321
Transmission Service Adjustment Rider ($/kW)	0.00	0.00
State Primary/Large Primary (E15/E17)		
Customer Charge ($/month)	0.00	0.00
Energy Charge (¢/kWh)		
All kWh	1.07	1.07
Demand Charge ($/kW)		
All kW	10.94	11.64
Pass-Through Charges		
Fuel Adjustment Charge (adjusted for TY) (¢/kWh)	3.321	3.321
Transmission Service Adjustment Rider ($/kW)	0.24819	0. 24819
Primary Service Long-Term Contract (LTC2/LTC3)		
Customer Charge ($/month)	0.00	0.00
Energy Charge (¢/kWh)		
On-Peak	1.71	2.41
Off-Peak	(0.29)	0.56
Demand Charge (On-Peak) ($/kW)		
All kW	11.40	12.54
Pass-Through Charges		
Fuel Adjustment Charge (adjusted for TY)(¢/kWh)	3.321	3.321
Transmission Service Adjustment Rider	0.00	0.00
Primary Service Long-Term Contract (LIR2/LIR3)		
Customer Charge ($/month)	0.00	0.00
Energy Charge (¢/kWh)		
On-Peak	1.67	2.35
Off-Peak	(0.30)	0.55
Demand Charge (On-Peak) ($/kW)		
All kW	11.12	12.23
Pass-Through Charges		
Fuel Adjustment Charge (adjusted for TY) (¢/kWh)	3.321	3.321
Transmission Service Adjustment Rider	0.00	0.00
Transmission Service Long-Term Contract (LIR2T)		
Customer Charge ($/month)	0.00	0.00

Table 7.1
Commercial and Industrial Customers – Summary of Existing Rates

Item	Winter Rate Period (November - April)	Summer Rate Period (May - October)
Energy Charge (¢/kWh)		
On-Peak **(¢/kWh)**	1.67	2.35
Off-Peak	(0.30)	0.55
Demand Charge (On-Peak) ($/kW)		
All kW	11.12	12.23
Pass-Through Charges		
Fuel Adjustment Charge (adjusted for TY) (¢/kWh)	3.279	3.279
Transmission Service Adjustment Rider	0.00	0.00
GreenChoice Option[(1)] (¢/kWh)		
Batch-3	3.300	3.300
Batch-4	3.500	3.500
Batch-5	5.500	5.500
Batch-6	5.700	5.700

Note:
1. In March 2001, AE developed and adopted its GreenChoice program to charge for an optional renewable energy pricing plan. Customers who subscribe to the GreenChoice program pay a renewable energy charge in lieu of the fuel adjustment clause as determined by AE. The GreenChoice charge remains fixed for a period of time (typically 10 or 15 years). The price associated with AE's renewable energy charge is dependent upon when the customer enrolls in the program. To date, AE has offered six "batches" of renewable energy each with an associated price and term based on AE's cost of purchasing the energy plus specific adders. Batch prices range from 1.7 cents per kWh for Batch-1 to the current price of 5.7 cents per kWh for Batch-6. Batch-1 and Batch-2 expired in March 2011. The current GreenChoice rate (Batch-6) is 5.7 cents per kWh compared to the current fuel charge of 3.105 cents per kWh for commercial customers served at the secondary voltage connection level.

Challenges Identified in Existing Commercial and Industrial Rate Structures

Austin Energy staff reviewed AE's existing commercial and industrial rate structures with consideration of the utility's strategic objectives and obtained public input to identify challenges with the utility's existing commercial and industrial rates. For the commercial and industrial rates, identified challenges to address in this rate review included the following:

- Existing small secondary service commercial class rates are below the cost of service for this customer class while larger commercial and industrial customer class rates are above cost of service levels, indicating that inter-class subsidization currently exists with these classes.
- Existing rate structures for many commercial and industrial customer classes do not reflect AE's unbundled cost of service results and do not provide flexibility to reflect changes in AE's cost of service in the future.

- Fixed cost recovery was limited in the existing rate structure for many commercial customer classes, particularly small commercial customers and customers with low load factors, and subjects AE to revenue instability due to unpredictable weather variations and declining load growth.
- The commercial and industrial rate structures should transparently reflect AE's cost of service and be understandable to customers.
- The existing seasonal summer peak rate period does not align with AE peak demand period and does not adequately reflect peak demand costs.
- Commercial and industrial rate structures should support technology adoption and customer choice through rate alternatives beneficial to both the environment and the utility.
- Commercial and industrial rate structures should protect AE from uncontrollable events or circumstances by way of pass-through charges that automatically change to reflect cost changes, including changes fuel-related costs.

Process Used to Address Commercial and Industrial Rate Structure Challenges

Austin Energy staff, along with its hired ratemaking experts, carefully reviewed rates research, completed new analysis, and obtained public input during the rate review process to address the identified commercial and industrial rate challenges. This information allowed the utility staff to develop proposed rates that achieve the class' cost of service while meeting the utility's strategic objectives and customer preferences. A balancing of sometimes conflicting objectives was completed as part of this iterative process to address the challenges with current residential rates. Components of AE's rate proposal for commercial and industrial customers that address these challenges include the following:

- Help AE achieve its revenue requirement by adjusting commercial and industrial rates to be within a plus or minus 5 percent range of the identified cost of service for each customer class.
- Improve equitable fixed cost recovery by introducing a fixed customer charge and fixed electric delivery charges, and transitioning to demand charges for all commercial and industrial classes.
- Encourage energy efficiency and conservation by introducing or increasing demand charges for all commercial and industrial classes and increasing the power factor adjustment for larger commercial and industrial classes.
- Recognize the need to provide affordable energy by transitioning existing commercial and industrial customers without demand charges to rate structures with increasing demand charges and reducing energy charges over time.
- Improve customer understandability and transparency of rates by unbundling rates to more closely reflect the costs to provide services; this includes

introducing a customer charge, an electric delivery charge, a demand charge, a regulatory charge, and a community benefit charges, and modifying the seasonal summer rate period from the current six-month period to a four-month period.

- Develop more sustainable rate structures that support AE's strategic objective for all commercial and industrial classes by better unbundling of rates and charges and introducing charges that can be adjusted more easily to reflect changes in AE's costs.

The process for determining the first component of this proposal was discussed in Section 5 of this report. How the components of AE's proposal for commercial and industrial rates supported by this report were derived is discussed in greater detail in this section of the report.

Proposed Standard Commercial and Industrial Rate Structures and Prices

Austin Energy's proposed commercial and industrial rate structures include a customer charge, electric delivery charge, energy charge, energy adjustment clause, regulatory charge, community benefit charge, and for some customers a power fact adjustment. These charges and adjustments are described in Section 5 of this report. A summary of the proposed rates for each proposed commercial and industrial customer class is provided as Table ES-5 in the Executive Summary to this report and more detail on the proposed rates by customer class is provided in this section of the report. Customer bill impacts for all current customer classes that would be relocated into the proposed customer classes. In the bill comparisons, the cumulative number of bills by load factor for each current customer class placed in a proposed class is shown to demonstrate the characteristics of that customer group. Results are shown at only one level of demand so while percentage increases in bill may be similar, the magnitude of the bill amounts will change depending on the actual level of demand of a customer. Section 2 provides detail on the proposed customer classes and the types of customers within each class to help customers determine which class they may be placed into under this proposal. All customers are placed into a class based on their service voltage and demand on the system. A customer's highest demand (in kW) during the proposed new summer rate period (June-September) determines the class the customer is placed in for a period of at least one year after which the demand level is reassessed for placement.

Additionally, a figure is provided for each proposed rate class that includes the cost of service curves for the proposed customer class compared to current rate curves for each current customer class that will have customers placed into the proposed new customer class. Unlike the representation of energy (kWh) consumption for the Residential customer class, for commercial and industrial customers it is more appropriate to select a typical customer (based on mean peak demand measured in kW) for each class and then represent the cost curve (in cents per kWh) based on variations in load factor. Load factor, discussed in more detail in Section 2 of this report, is the relationship between demand and energy and is a measure of the consistency of power usage over time. Utility rate structures often reward higher load factors with lower average rates because the fixed costs incurred to serve the customers are spread over a large amount of energy. Therefore, it costs less to serve these customers per unit of energy consumed.

Figure 7.1 in the section below provides an example of how the results of this study are presented in this section. Figure 7.1 is a representative customer of 3 kW for the Secondary Voltage <10 kW customer class was selected based on the mean billed demand per monthly electricity bill for all customers in the class. Also in Figure 7.1, bill frequency blocks based on load factor in the months of FY 2009 are represented on the x-axis in 10 percent increments. For instance, the 10 percent block represents all bills for the customer class over the course of the year with a load factor between 0 and 10 percent. The number of bills over the course of year is listed on the y-axis at the right side of the graph.

The shape of the unbundled cost of service cost curve in Figure 7.1 is a typical cost of service-based cost curve for any customer class. As customers use more energy per kW of demand (represented by a higher load factor), the average cost of service (represented in cents per kWh) typically decreases. This is because fixed costs that a utility incurs in order to serve a customer are borne regardless of customer monthly electricity usage or load factor.

Customers with higher monthly load factors use more energy and have a lower average cost of service as fixed costs are recovered over a greater number of units of electricity consumed (in kWh). Conversely, customers with low monthly load factors use relatively less energy and have a relatively high average cost of service as fixed costs are recovered over fewer kWh. The cost curve gradually decreases and then flattens out as more electricity is consumed and costs are spread out among more units of electricity (kWh) consumed. However, while the average cost of service in $/kWh may be higher for lower load factor customers, their actual monthly electricity bills tend to be lower than the bill for a customer who consumes more electricity.

Proposed Standard Secondary Voltage <10 kW Rate Structure and Prices

Table 7.2 compares the existing General Service Non-Demand (E02) rates with the proposed Secondary Voltage <10 kW rate as 98 percent of the customers in the proposed Secondary Voltage <10 kW customer class are currently billed under the General Service Non-Demand rates. Other existing customers included in this proposed customer class are the following customers whose maximum demand on the system is less than 10 kW:

- Worship facilities currently served under the Residential (E01C) rate;
- State General Service Non-Demand (E13) customers (bill impact results not shown as State recently re-negotiated their rates); and
- City of Austin facilities currently served under the Other City (E04) rate.

Currently, these customers are not assessed a demand charge. A demand charge is being recommended to be applied to these customers under the new rate in order to improve fixed cost recovery, minimize inter-class subsidization, and send stronger pricing signals to encourage energy efficiency improvements and conservation. The Electric Delivery Charge and Demand Charge will be phased in over a three-year period to help customers in this class adjust to the new rate structure and mitigate any rate shock for low load factor customers. The Phase 1 (Proposed Rate FY 2012) for all proposed transition rates would be implemented at the point in which new rates are approved in FY 2012 and the second and third phases would occur in either the beginning of the following fiscal years, the beginning of the following calendar years, or at a time to be determined by AE staff. The transition rate proposed for Secondary Service Voltage <10 kW customer class is shown in Table 7.2. As the percent class rate change row shows, the rate is designed each year to fully recover the class' revenue requirement, but the demand charge is gradually increased as the energy charge is reduced. Thus, more costs will shift to low load factor customers during this transition to move towards cost of service and minimize inter-class subsidization.

Table 7.2
Secondary Voltage <10 kW: Existing General Service Non-Demand (E02) Rate vs. Proposed Transition Rate

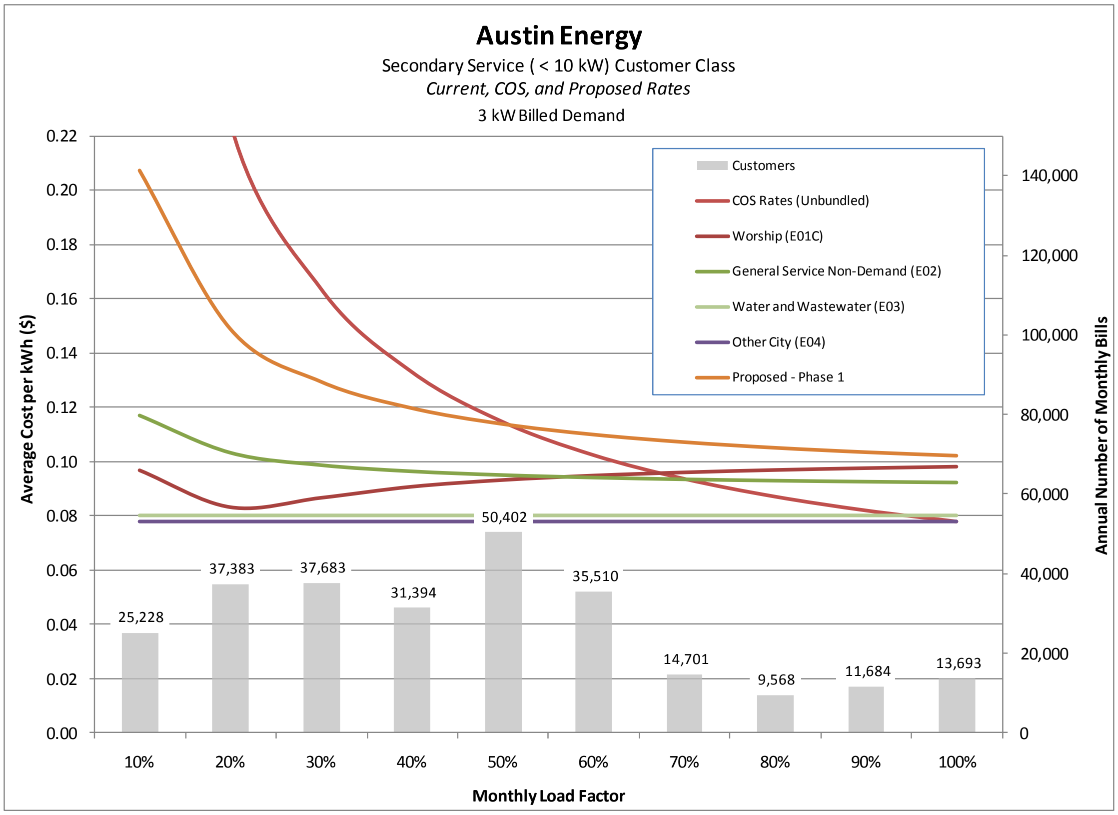
Name of Charge/Rate	Existing Rate with TY Adjusted Fuel (1)	Proposed Rate FY 2012	Proposed Rate FY 2013	Proposed Rate FY 2014
Customer Charge ($/month)	6.00	18.00	18.00	18.00
Electric Delivery Charge ($/kW billed)	n/a	1.50	1.50	2.50
Demand Charge ($/kW-billed) (2)				
Summer (3)	n/a	1.00	1.50	3.00
Non-summer (3)	n/a	1.00	1.50	3.00
Energy Charge (¢/kWh) (4)				
Summer (3)	9.838	9.097	8.924	8.054
Non-summer (3)	8.038	7.278	7.139	6.443
Energy Adjustment (¢/kWh) (5)	n/a	0.00	0.00	0.00
Community Benefit Charge (6)				
Customer Assistance Program (¢/kWh)	n/a	0.065	0.065	0.065
Service Area Street Lighting (¢/kWh)	n/a	0.113	0.113	0.113
Energy Efficiency Charge (¢/kWh)	n/a	0.296	0.296	0.296
Regulatory Charge ($/kW) (7)	n/a	0.00	2.33	2.33
Regulatory Charge (¢/kWh) (7)		0.711	0.000	0.000
Transmission Service Adjustment Rider (¢/kWh) (8)	0.078	n/a	n/a	n/a
Percent Class Rate Change		21.8	21.8	21.8

Notes:
1. Represents the predominant rate currently effective for this customer class (General Service Non-Demand – E02). Other existing rates may be applicable to specific customers within this new proposed customer class.
2. Billed demand applicable to the demand charge is based on a customer's maximum monthly demand.
3. The summer season under the current rate structure is from May through October; the non-summer season under the current rate structure is from November through April. Under the proposed rate structure, summer season would be June through September and non-summer season would be October through May.
4. AE's existing Energy Charge does not include fuel-related costs. Fuel is charged separately through the Fuel Adjustment Clause. The Energy Charge shown here includes fuel-related costs based on the normalized TY revenue requirement results (TY 2009 fuel adjustment charge is 3.398 cents per kWh) as these costs are not part of the requested base rate increase.
5. The Energy Adjustment is a new charge that replaces the current Fuel Adjustment Clause. The Energy Adjustment is set to zero but is subject to change as described in Section 5 of this report.
6. The Community Benefit Charge is a new charge that funds three specific programs and services provided to the community by AE. The Customer Assistance Program creates monies to provide discounts to qualified low-income and other disadvantaged customers. Service Area Lighting recovers the cost of street lighting to customers within the entire AE service territory. Energy efficiency recovers the cost of energy efficiency, green building, and solar rebate programs offered by AE.
7. The Regulatory Charge is a new charge that replaces the Transmission Service Adjustment Rider and includes ERCOT administration fees and charges associated with AE's cost of ERCOT transmission.
8. The Transmission Service Adjustment is a current charge associated with AE's increased cost of ERCOT transmission to support State transmission build-out. This adjustment would be discontinued under the proposed rate structure and these costs would be included in the new Regulatory Charge.

Secondary Voltage <10 kW Customer Electric Bill Impact Analysis

Figure 7.1 shows the impact of the proposed Phase 1 (FY 2012) rate compared to current rates for all customers in the Secondary Voltage <10 kW class. The graphic shows a monthly bill expressed on a $/kWh basis over a range of monthly load factors. The graphic includes a histogram that shows the number of customers within the Secondary Voltage <10 kW class by load factor. The histogram indicates that the majority of customers in the Secondary Voltage <10 kW class have relatively low monthly load factors ranging from 10 percent to 60 percent.

Figure 7.1
Rate Design Results – Secondary Voltage <10 kW
Current and Proposed Rates (in $/kWh): 3 kW Customer



The proposed rate structure for Secondary Voltage <10 kW, which includes a demand component, provides improved fixed cost recovery with the average rate declining as the load factor increases. The proposed rate reduces intra-class and inter-class subsidization by pricing close to the cost of service. All customers placed in this class, including City of Austin facilities, would see an increase in their average rate during Phase 1 regardless of load factor.

Secondary Voltage <10 kW electric bill comparisons for each group of customers that will be placed in this class are shown in Tables 7.3 through 7.6. Please note that some existing customer classes, such as worship, will have customers distributed to multiple classes depending on the customer's service voltage and demand level. More extensive bill comparison data can be found in Appendix G.

Table 7.3
Residential Worship (EO1C) Rate Compared to Proposed Secondary Voltage <10 kW Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill [(1)]

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	59	94	99	100	100
Current Bill ($)	21.22	56.94	102.13	147.32	192.52
Bill at Proposed Rates ($)	45.36	85.09	124.81	164.53	204.26
Dollar Increase ($)	24.15	28.15	22.68	17.21	11.74
Percent Increase (%)	114	49	22	12	6

Note:
1. Assumes a customer with a 3 kW monthly peak.

Table 7.4
General Service Non-Demand (E02) Rate Compared to Secondary Voltage <10 kW Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill [(1)]

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	12	44	73	90	96
Current Bill ($)	25.57	64.72	103.87	143.02	182.17
Bill at Proposed Rates ($)	45.36	85.09	124.81	164.53	204.26
Dollar Increase ($)	19.79	20.36	20.94	21.52	22.09
Percent Increase (%)	77	31	20	15	12

Note:
1. Assumes a customer with a 3 kW monthly peak.

Table 7.5
Water & Wastewater (E03) Rate Compared to Secondary Voltage <10 kW Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill [(1)]

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	21	52	75	89	97
Current Bill ($)	17.57	52.71	87.85	122.99	158.13
Bill at Proposed Rates ($)	45.36	85.09	124.81	164.53	204.26
Dollar Increase ($)	27.79	32.38	36.96	41.54	46.13
Percent Increase (%)	158	61	42	34	29

Note:
1. Assumes a customer with a 3 kW monthly peak.

Table 7.6
Other City (E04) Rate Compared to Secondary Voltage <10 kW Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill (1)

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	18	43	70	89	97
Current Bill ($)	17.02	51.07	85.11	119.16	153.20
Bill at Proposed Rates ($)	45.36	85.09	124.81	164.53	204.26
Dollar Increase ($)	28.34	34.02	39.70	45.37	51.05
Percent Increase (%)	166	67	47	38	33

Note:
1. Assumes a customer with a 3 kW monthly peak.

These results demonstrate that low load factor customers (particularly those with a load factor of 10 percent or less) will have the highest percentage increase in bill in the proposed Secondary Voltage <10 kW class, but will have the lowest dollar increase. This is expected as low load factor customers shown in this analysis place the same level of demand on the system, but use relatively less energy over the month. The demand charge is intended to send a pricing signal for these low load factor customers to create an incentive for these customers to lower their peak demand (when costs to the utility are highest) or shift electricity usage to off-peak periods (when costs to the utility are lower). Monthly electric bill increases for a 3 kW customer in this proposed class are estimated to range from about $20 to $50 a month depending on the customer's current class and load factor.

Proposed Standard Secondary Voltage 10 kW – <50 kW Rate Structure and Prices

Table 7.7 compares the existing General Service Demand (E06) rate with the proposed Secondary Voltage 10 kW – <50 kW rate as 72 percent of the customers in the proposed Secondary Voltage 10 kW – <50 kW customer class are currently billed under the General Service Demand rate. Other existing customers included in this proposed customer class include the following customers whose maximum demand for power is 10 kW – <50 kW:

- Worship facilities currently served under the Residential (E01C) rate;
- Small commercial customers with maximum demand 10 kW - <20 kW currently served under the General Service Non-Demand (E13 for State customers and E02 for all others, bill impact results not shown for E13 as State recently re-negotiated their rates);
- City of Austin water and wastewater facilities (E03);
- City of Austin facilities currently served under the Other City (E04) rate;

- State General Service Demand (E14) customers (bill impact results not shown as State recently re-negotiated their rates); and
- Independent school districts (E23).

The majority of customers in the proposed class have a demand charge under their existing rate structure. The exception is current General Service Non-Demand, worship facilities, and City of Austin facilities moving to this class. Austin Energy is proposing that a demand charge be introduced to these customers in order to improve fixed cost recovery and send a stronger pricing signal to these customers for making energy efficiency improvements and conservation.

Similar to the approach taken with Secondary Voltage <10 kW customers, AE is recommending that the demand and electric delivery charges for these customers be phased in over a three-year period. Because the proposed Secondary Voltage 10 kW – <50 kW customer class combines customers with and without demand charges, the rate tariff will include two rate classes. The rate structure shown in Table 7.7 will only apply to customers that currently have a demand charge. These customers will move to the proposed Secondary Voltage 10 - <50 kW rate in a single step.

Table 7.7
Secondary Voltage 10 kW – <50 kW
Existing General Service Demand (E06) Rate vs. Proposed Rate
(Applicable to customers who currently have demand charges)

Name of Charge/Rate	Existing Rate with TY Adjusted Fuel (1)	Proposed Rate
Customer Charge ($/month)	0.00	25.00
Electric Delivery Charge ($/kW-billed)	n/a	4.00
Demand Charge ($/kW-billed) (2)		
Summer (3)	14.03	6.50
Non-summer (3)	12.65	5.50
Energy Charge (¢/kWh)(4)		
Summer (3)	5.198	5.868
Non-summer (3)	5.198	5.491
Energy Adjustment (¢/kWh) (5)	n/a	0.00
Community Benefit Charge (6)		
Customer Assistance Program (¢/kWh)	n/a	0.065
Service Area Street Lighting (¢/kWh)	n/a	0.088
Energy Efficiency Charge (¢/kWh)	n/a	0.231
Regulatory Charge ($/kW) (7)	n/a	2.44
Transmission Service Adjustment Rider ($/kW) (8)	0.2668	n/a
Percent Class Rate Change		8.9

Notes:
1. Represents the predominant rates currently effective for this customer class (General Service Demand – E06). Other existing rates may be applicable to specific customers within this new proposed customer class.
2.-8. See Table 7.2.

The rate structure shown in Table 7.8 is applicable to customers that are not currently billed on demand and will now be placed in the Secondary Voltage 10 – <50 kW class. This rate class will include a three-year phase in of demand rates so that the concept of demand and the resulting bill impacts are gradually introduced to these customers. The three-year phase in proposal is shown in the Table 7.8. In the third year, all customers in this class will be served under the same rate.

Table 7.8
Secondary Voltage 10 kW – <50 kW General Service Demand (E06) Rate vs. Proposed Rate
(Applicable to customers that currently do not have demand charges)

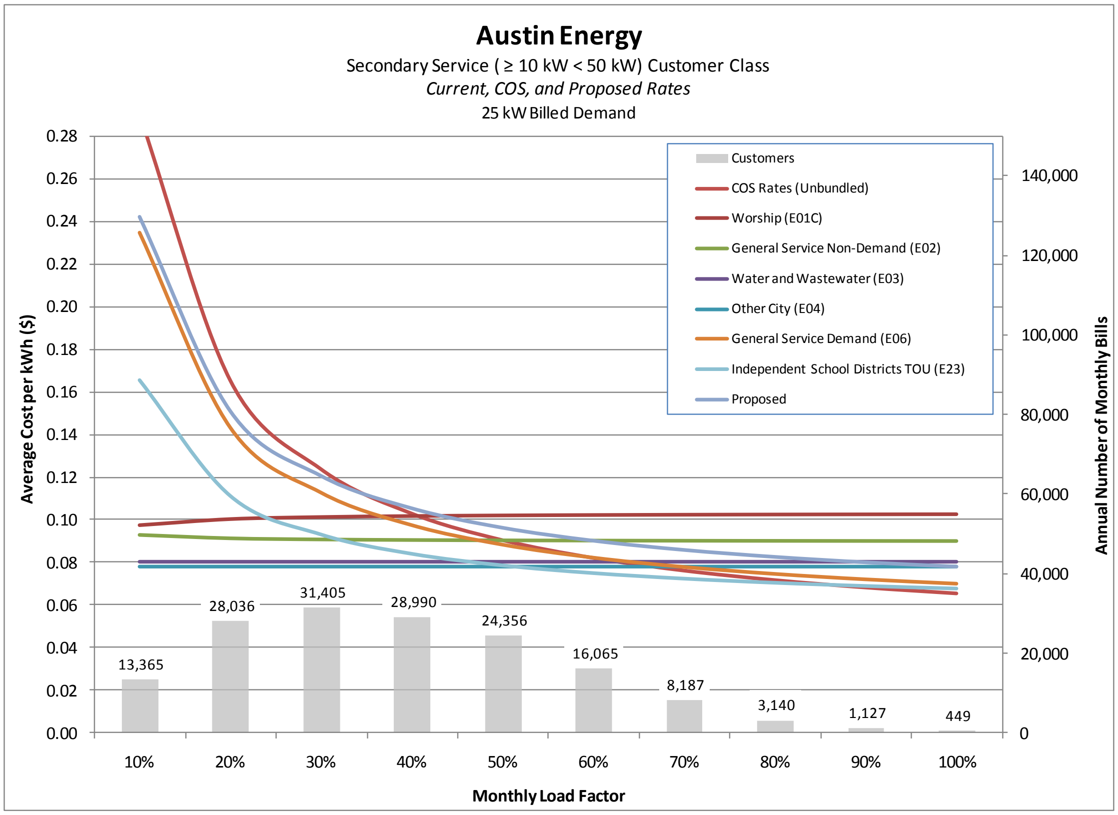
Name of Charge/Rate	Existing Rate with TY Adjusted Fuel (1)	Proposed Rate FY 2012	Proposed Rate FY 2013	Proposed Rate FY 2014
Customer Charge ($/month)	6.00	25.00	25.00	25.00
Electric Delivery Charge ($/kW-billed)	n/a	2.00	2.50	4.00
Demand Charge ($/kW-billed) (2)				
Summer (3)	n/a	2.00	4.50	6.50
Non-summer (3)	n/a	2.00	4.00	5.50
Energy Charge (¢/kWh) (4)				
Summer (3)	9.838	7.505	6.758	5.868
Non-summer (3)	8.038	7.023	6.324	5.491
Energy Adjustment (¢/kWh) (5)	n/a			
Community Benefit Charge (6)				
Customer Assistance Program (¢/kWh)	n/a	0.065	0.065	0.065
Service Area Street Lighting (¢/kWh)	n/a	0.088	0.088	0.088
Energy Efficiency Charge (¢/kWh)	n/a	0.231	0.231	0.231
Regulatory Charge (S/kW) (7)	n/a	2.44	2.44	2.44
Transmission Service Adjustment Rider (¢/kWh) (8)	0.078	n/a	n/a	n/a
Percent Class Rate Change		8.9	8.9	8.9

Notes:
1. Existing rate for customers in the current General Service Non Demand class (E02) customer class. Other existing rates may be applicable to specific customers within this new proposed customer class.
2.-8. See Table 7.2.

Secondary Voltage 10 kW – <50 kW Customer Electric Bill Impact Analysis

Figure 7.2 shows the impact of the proposed rates compared to current rates for all customers in the proposed Secondary Voltage 10 – <50 kW class. The graphic shows a monthly electric bill expressed on a $/kWh basis over a range of monthly load factors. The graphic provides a histogram that shows the number of customers within the Secondary Voltage 10 – <50 kW class by load factor. The histogram indicates that the majority of customers in the Secondary Voltage 10 – <50 kW class have monthly load factors ranging from 20 percent to 50 percent.

Figure 7.2
Rate Design Results – Secondary Voltage 10 kW – <50 kW
Current and Proposed Rates (in $/kWh): 25 kW Customer



The proposed rate structure would improve fixed cost recovery and the average rate would decline as customer load factor increases. Intra-class and inter-class subsidization would be mitigated by pricing close to the cost of service. Current General Service Demand (E06) customers would experience a moderate increase in their average rate. Most worship facilities would receive an increase with worship facilities with a load factor greater than approximately 45 percent (which are very few of these customers) receiving a rate decrease. Most General Service Non-Demand customers would also see an increase, expect for those with a load factor of greater than 60 percent which would see a reduction from their current rate. Independent school districts would have a rate increase; however, a TOU rate option that will be offered may help moderate these rate impacts. City of Austin facilities, including water and wastewater facilities, would see an increase in their average rate at almost all load factors.

Secondary Voltage 10 kW – <50 kW electric bill comparisons for each group of customers that will be placed in this class are shown in Tables 7.9 through 7.14. Please note that some existing customer classes, such as worship, will have customers distributed to multiple classes depending on the customer's service voltage and demand level. More extensive bill comparison data can be found in Appendix G.

Table 7.9
Worship (E01C) Rate Compared to Secondary Voltage 10 – <50 kW Transition Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill (1)

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	35	92	100	100	100
Current Bill ($)	177.45	554.05	930.66	1,307.26	1,683.86
Bill at Proposed Rates ($)	324.11	600.33	876.55	1,152.77	1,428.99
Dollar Increase ($)	146.66	46.28	(54.11)	(154.49)	(254.87)
Percent Increase (%)	83	8	-6	-12	-15

Note:
1. Assumes a customer with a 25 kW monthly peak.

Table 7.10
General Service Non-Demand (E02) Rate Compared to Secondary Voltage 10 – <50 kW Transition Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill (1)

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	12	44	73	90	96
Current Bill ($)	169.12	495.35	821.58	1,147.81	1,474.05
Bill at Proposed Rates ($)	324.11	600.33	876.55	1,152.77	1,428.99
Dollar Increase ($)	154.99	104.98	54.97	4.96	(45.06)
Percent Increase (%)	92	21	7	0	-3

Note:
1. Assumes a customer with a 25 kW monthly peak.

Table 7.11
Water & Wastewater (E03) Rate Compared to Secondary Voltage 10 – <50 kW Transition Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill (1)

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	21	52	75	89	97
Current Bill ($)	146.42	439.25	732.09	1,024.92	1,317.76
Bill at Proposed Rates ($)	324.11	600.33	876.55	1,152.77	1,428.99
Dollar Increase ($)	177.69	161.08	144.46	127.85	111.23
Percent Increase (%)	121	37	20	12	8

Note:
1. Assumes a customer with a 25 kW monthly peak.

Table 7.12
Other City Demand (E04) Rate Compared to Secondary Voltage 10 – <50 kW Transition Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill (1)

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	18	43	70	89	97
Current Bill ($)	141.85	425.56	709.27	992.98	1,276.69
Bill at Proposed Rates ($)	324.11	600.33	876.55	1,152.77	1,428.99
Dollar Increase ($)	182.26	174.77	167.28	159.79	152.30
Percent Increase (%)	128	41	24	16	12

Note:
1. Assumes a customer with a 25 kW monthly peak.

Table 7.13
General Service Demand (E06) Rate Compared to Secondary Voltage 10 – <50 kW Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill (1)

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	2	25	67	94	99
Current Bill ($)	428.36	618.08	807.81	997.53	1,187.25
Bill at Proposed Rates ($)	441.35	660.37	879.39	1,098.42	1,317.44
Dollar Increase ($)	12.98	42.29	71.59	100.89	130.19
Percent Increase (%)	3	7	9	10	11

Note:
1. Assumes a customer with a 25 kW monthly peak.

Table 7.14
Independent School District Time-of-Use (E23) Rate Compared to Secondary Voltage 10 – <50 kW Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill (1)

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	1	40	92	98	100
Current Bill ($)	302.47	509.91	717.35	924.79	1,132.23
Bill at Proposed Rates ($)	441.35	660.37	879.39	1,098.42	1,317.44
Dollar Increase ($)	138.88	150.46	162.04	173.63	185.21
Percent Increase (%)	46	30	23	19	16

Note:
1. Assumes a customer with a 25 kW monthly peak.

These results demonstrate that low load factor customers (particularly those with a load factor of 10 percent or less who do not currently have a demand charge) will have the highest percentage increase in bill in the proposed Secondary Voltage 10 – <50 kW class, but will have the lowest dollar increase in bill. This is expected as low load factor customers shown in this analysis place the same level of demand on the system, but use relatively less energy over the month. The demand charge is intended to send a pricing signal for these low load factor customers to create an incentive for these customers to lower their peak demand (when costs to the utility are highest) or shift electricity usage to off-peak periods (when costs to the utility are lower). Seventy-two percent of the customers that will be placed in this customer class are currently in the General Service Demand class. Monthly electric bill impacts for current 25 kW General Service Demand customer placed in this customer class range from an increase of about $13 to $130 a month depending on the customer's load factor, but no customer will have an percentage increase in their bill of greater than 11 percent.

Proposed Standard Secondary Voltage ≥50 kW Rate Structure and Prices

Table 7.15 compares the existing General Service Demand (E06) rate with the proposed Secondary Voltage ≥50 kW rate as 79 percent of the customers in the proposed Secondary Voltage ≥50 kW customer class are currently billed under the General Service Demand rate. Other existing customers included in this proposed customer class are the following customers whose maximum demand for power is ≥50 kW:

- Worship facilities currently served under the Residential (E01C) rate;
- City of Austin water and wastewater facilities (E03);
- City of Austin facilities currently served under the Other City (E04);
- State General Service Demand (E14) customers (bill impact results not shown as State recently re-negotiated their rates);
- Independent school districts (E23); and
- After their contract expires in May of 2015 certain special contract customers.

Currently, all of these customers, other than worship facilities and City of Austin facilities, are assessed a demand charge. Similar to other secondary voltage classes, AE is proposing to introduce and phase in demand rates for worship, water and wastewater facilities, and other City of Austin facilities placed in this customer class. Because the new Secondary Voltage ≥50 kW customer class combines customers with and without demand charges, the rate tariff will include two rate classes. The rate structure presented in Table 7.15 will apply to customers that currently have a demand charge. These customers will move to the proposed Secondary Voltage ≥50 kW rate in a single step as shown in Table 7.15.

Table 7.15
Secondary Voltage ≥50 kW
Existing General Service Demand (E06) Rate vs. Proposed Rate
(Applicable to Customers that currently have Demand Charges)

Name of Charge/Rate	Existing Rate with TY Adjusted Fuel (1)	Proposed Rate
Customer Charge ($/month)	0.00	65.00
Electric Delivery Charge ($/kW-billed)	n/a	4.50
Demand Charge ($/kW-billed) (2)		
Summer (3)	14.03	8.00
Non-summer (3)	12.65	7.00
Energy Charge (¢/kWh) (4)		
Summer (3)	5.198	5.142
Non-summer (3)	5.198	4.812
Energy Adjustment (¢/kWh) (5)	n/a	0.00
Community Benefit Charge (6)		
Customer Assistance Program (¢/kWh)	n/a	0.065
Service Area Street Lighting (¢/kWh)	n/a	0.078
Energy Efficiency Charge (¢/kWh)	n/a	0.206
Regulatory Charge ($/kW) (7)	n/a	2.57
Transmission Service Adjustment Rider ($/kW) (8)	0.2668	n/a
Percent Class Rate Change		5.8

Notes:
1. Represents the predominant rates currently effective for this customer class (General Service Demand – E06). Other existing rates may be applicable to specific customers within this new proposed customer class.
2.-8. See Table 7.2.

The rate structure shown in Table 7.16 would be applicable to customers that are not currently billed on demand. This rate class will include a three-year phase in of demand rates so that the concept of demand and the resulting bill impacts are gradually introduced to these customers. The three-year phase in proposal is shown in Table 7.16. In the third year, all customers in this class will be served under the same rate.

Table 7.16
Secondary Voltage ≥50 kW
Existing General Service Demand (E06) Rate vs. Proposed Rate
(Applicable to Customers that currently do not have Demand Charges)

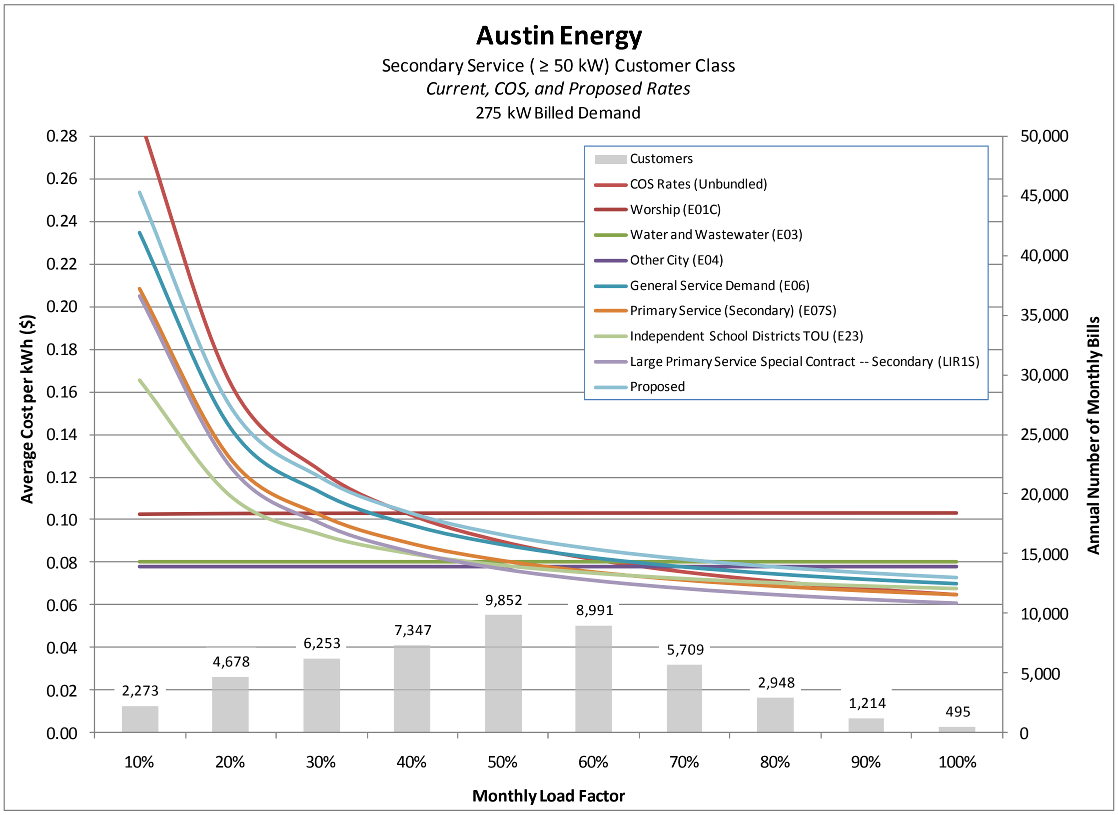
Name of Charge/Rate	Existing Rate with TY Adjusted Fuel (1)	Proposed Rate FY 2012	Proposed Rate FY 2013	Proposed Rate FY 2014
Customer Charge ($/month)	6.00	65.00	65.00	65.00
Electric Delivery Charge ($/kW-billed)	n/a	2.00	4.00	4.50
Demand Charge ($/kW-billed) (2)				
Summer (3)	n/a	2.00	5.00	8.00
Non-summer (3)	n/a	2.00	4.00	7.00
Energy Charge (¢/kWh) (4)				
Summer (3)		7.855	6.026	5.142
500 kWh or less	6.948			
501 kWh+	11.218			
Non-summer (3)		7.351	5.639	4.812
500 kWh or less	6.948			
501 kWh+	9.418			
Energy Adjustment (¢/kWh) (5)	n/a	0.00		
Community Benefit Charge (6)				
Customer Assistance Program (¢/kWh)	n/a	0.065	0.065	0.065
Service Area Street Lighting (¢/kWh)	n/a	0.078	0.078	0.078
Energy Efficiency Charge (¢/kWh)	n/a	0.206	0.206	0.206
Regulatory Charge (S/kW) (7)	n/a	2.57	2.57	2.57
Transmission Service Adjustment Rider (¢/kWh) (8)	0.086	n/a	n/a	n/a
Percent Class Rate Change		5.8	5.8	5.8

Notes:
1. Existing rate for customers in the current Worship (E01C) customer class. Other existing rates may be applicable to specific customers within this new proposed customer class.
2.-8. See Table 7.2.

Secondary Voltage ≥50 kW Customer Electric Bill Impact Analysis

Figure 7.3 shows the impact of the proposed rate compared to current rates for all customers that will be placed in the Secondary Voltage ≥50 kW class. The graphic shows a monthly electric bill expressed on a $/kWh basis over a range of monthly load factors. The graphic provides a histogram that shows the number of customers within the Secondary Voltage ≥50 kW class by load factor. The histogram indicates that the majority of customers in this customer class have monthly load factors ranging from 20 percent to 70 percent.

Figure 7.3
Rate Design Results – Secondary Voltage ≥50 kW
Current and Proposed Rates (in $/kWh): 275 kW Customer



The proposed rate structure aligns closely with the cost of service results cost curve as the average rate would go down as the load factor increases. Current General Service Demand (E06) customers will see moderate increases in their average rate. Most worship facilities in this class will have a rate increase, with the exception of facilities with load factor greater than 40 percent (which is very few customers). Independent school districts would have a rate increase; however, a TOU rate option that will be offered may help moderate these rate impacts. City of Austin facilities, including water and wastewater facilities, would see an increase in their average rate except at very high load factors. Those in special contracts who are in this customer class will not see increases in their bill as they are locked in to their current rate by contract through May 2015. At the expiration of those contracts these customers would receive a rate increase if priced at the proposed rate.

Secondary Voltage ≥50 kW electric bill comparisons for each group of customers that will be placed in this class are shown in Tables 7.17 through 7.25. Please note that some existing customer classes, such as worship, will have customers distributed to multiple classes depending on the customer's service voltage and demand level. More extensive bill comparison data can be found in Appendix G.

Table 7.17
Worship (E01C) Rate Compared to Secondary Voltage ≥50 kW Transition Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill [1]

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of Bills	13	83	98	100	100
Current Bill ($)	2,060.46	6,203.09	10,345.71	14,488.34	18,630.96
Bill at Proposed Rates ($)	3,451.25	6,610.25	9,769.26	12,928.26	16,087.26
Dollar Increase ($)	1,390.79	407.17	(576.46)	(1,560.08)	(2,543.70)
Percent Increase (%)	67	7	-6	-11	-14

Note:
1. Assumes a customer with a 275 kW monthly peak.

Table 7.18
Water & Wastewater (E03) Rate Compared to Secondary Voltage ≥50 kW Transition Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill [1]

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	21	52	75	89	97
Current Bill ($)	1,610.59	4,831.77	8,052.96	11,274.14	14,495.32
Bill at Proposed Rates ($)	3,451.25	6,610.25	9,769.26	12,928.26	16,087.26
Dollar Increase ($)	1,840.66	1,778.48	1,716.30	1,654.12	1,591.94
Percent Increase (%)	114	37	21	15	11

Note:
1. Assumes a customer with a 275 kW monthly peak.

Table 7.19
Other City Demand (E04) Rate Compared to Secondary Voltage ≥50 kW Transition Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill [1]

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	18	43	70	89	97
Current Bill ($)	1,560.40	4,681.21	7,802.02	10,922.83	14,043.63
Bill at Proposed Rates ($)	3,451.25	6,610.25	9,769.26	12,928.26	16,087.26
Dollar Increase ($)	1,890.85	1,929.04	1,967.24	2,005.43	2,043.62
Percent Increase (%)	121	41	25	18	15

Note:
1. Assumes a customer with a 275 kW monthly peak.

Table 7.20
General Service Demand (E06) Rate Compared to Secondary Voltage ≥50 kW Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill (1)

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	2	25	67	94	99
Current Bill ($)	4,711.97	6,798.92	8,885.86	10,972.81	13,059.75
Bill at Proposed Rates ($)	5,084.07	7,200.38	9,316.68	11,432.99	13,549.30
Dollar Increase ($)	372.10	401.46	430.82	460.18	489.54
Percent Increase (%)	8	6	5	4	4

Note:
1. Assumes a customer with a 275 kW monthly peak.

Table 7.21
Independent School District Time-of-Use (E23) Rate Compared to Secondary Voltage ≥50 kW Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill (1)

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	1	40	92	98	100
Current Bill ($)	3,015.05	5,296.89	7,578.74	9,860.58	12,142.42
Bill at Proposed Rates ($)	5,084.07	7,200.38	9,316.68	11,432.99	13,549.30
Dollar Increase ($)	2,069.02	1,903.49	1,737.95	1,572.41	1,406.87
Percent Increase (%)	69	36	23	16	12

Note:
1. Assumes a customer with a 275 kW monthly peak.

Table 7.22
Special Contract (LIR1S) Rate Compared to Secondary Voltage ≥50 kW Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill (1)

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	0	4	14	61	97
Current Bill ($)	4,109.56	5,907.42	7,705.29	9,503.15	11,301.02
Bill at Proposed Rates ($)	5,084.07	7,200.38	9,316.68	11,432.99	13,549.30
Dollar Increase ($)	974.51	1,292.95	1,611.39	1,929.84	2,248.28
Percent Increase (%)	24	22	21	20	20

Note:
1. Assumes a customer with a 275 kW monthly peak.

Table 7.23
Special Contract (LIR2S/LIR3S) Rate Compared to Secondary Voltage ≥50 kW Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill [1]

	10% LF	30% LF	50% LF	70% LF	90% LF
Current Bill ($)	4,008.66	5,604.73	7,200.80	8,796.87	10,392.95
Bill at Proposed Rates ($)	5,084.07	7,200.38	9,316.68	11,432.99	13,549.30
Dollar Increase ($)	1,075.41	1,595.64	2,115.88	2,636.11	3,156.35
Percent Increase (%)	27	28	29	30	30

Note:
1. Assumes a customer with a 275 kW monthly peak.

Table 7.24
Special Contract (LTC 1S) Rate Compared to Secondary Voltage ≥50 kW Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill [1]

	10% LF	30% LF	50% LF	70% LF	90% LF
Current Bill ($)	4,196.71	6,006.62	7,816.53	9,626.44	11,436.35
Bill at Proposed Rates ($)	5,084.07	7,200.38	9,316.68	11,432.99	13,549.30
Dollar Increase ($)	887.36	1,193.76	1,500.16	1,806.55	2,112.95
Percent Increase (%)	21	20	19	19	18

Note:
1. Assumes a customer with a 275 kW monthly peak.

Table 7.25
Special Contract (LTC2S/LTC3S) Rate Compared to Secondary Voltage ≥50 kW Rate: Electric Bill Comparison

Annual Average Monthly Electricity Bill [1]

	10% LF	30% LF	50% LF	70% LF	90% LF
Cumulative % of bills	18	22	55	68	96
Current Bill ($)	4,144.21	5,849.13	7,554.04	9,258.96	10,963.88
Bill at Proposed Rates ($)	5,084.07	7,200.38	9,316.68	11,432.99	13,549.30
Dollar Increase ($)	939.86	1,351.25	1,762.64	2,174.03	2,585.42
Percent Increase (%)	23	23	23	23	24

Note:
1. Assumes a customer with a 275 kW monthly peak.

79 percent of the customers that will be placed in this customer class are currently in the General Service Demand class. Monthly electric bill impacts for current 275 kW General Service Demand customers placed in this customer class would range from an increase of only 4 (for high load factors) to 8 percent (low load factor). The demand charge is intended to send a pricing signal for low load factor customers to create an

incentive for these customers to lower their peak demand (when costs to the utility are highest) or shift electricity usage to off-peak periods (when costs to the utility are lower). Other customers who will be placed in this customer class would generally see a rate increase in the 20 to 30 percent range.

Proposed Standard Primary Voltage <3 MW Rate Structure and Prices

Table 7.26 compares the existing Primary Service (E07) rates with the proposed Primary Voltage <3 MW rates as 86 percent of the customers in the proposed Primary Voltage <3 MW customer class are currently billed under the Primary Service rates. Other existing customers included in this proposed customer class are other city and water and wastewater customers (bill impact results not show her) State facilities (E17) who receive service at the primary connection voltage level and whose maximum demand for power is <3 MW and certain special contract (LIR2/LIR3 and LTC2/LTC3) customers served at the primary voltage level whose maximum demand for power is <3MW. Bill impact results are not shown for State customers as they recently re-negotiated their rates. Currently, all of the customers that will be placed in this class are assessed a demand charge.

Table 7.26
Primary Voltage <3 MW
Existing Primary Service (E07) Rate vs. Proposed Rate

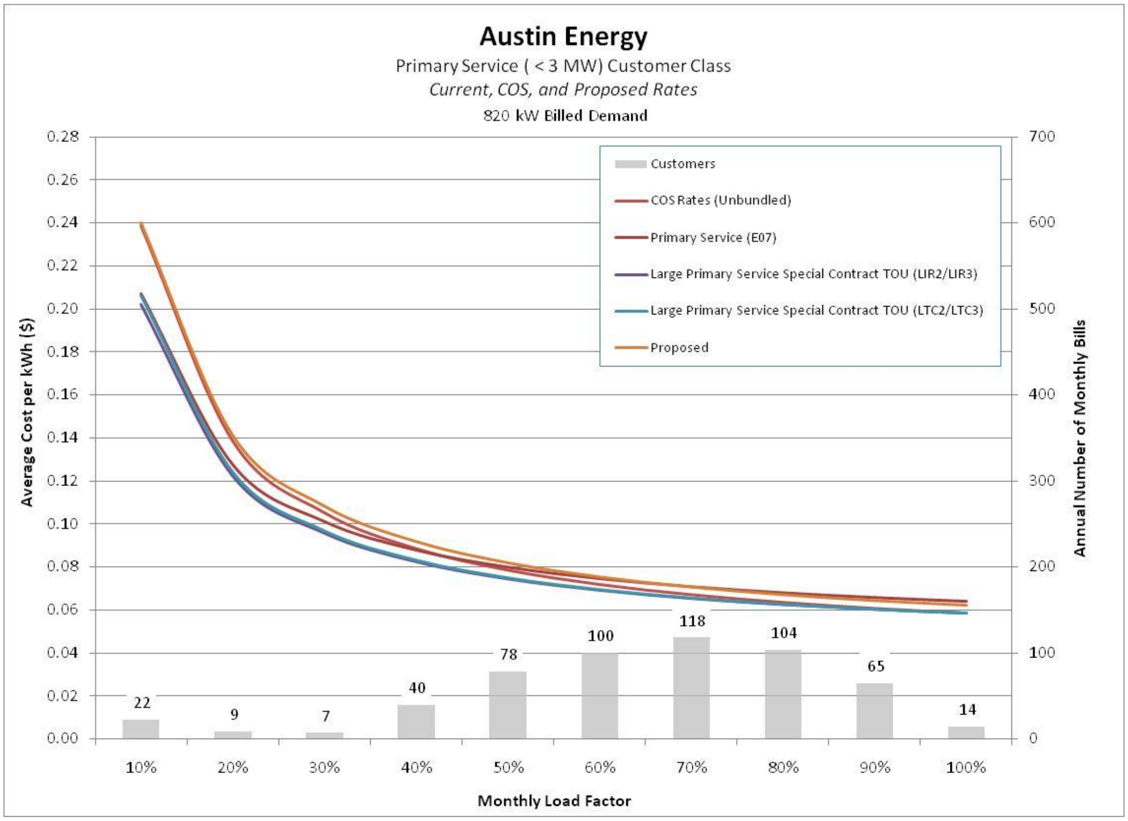
Name of Charge/Rate	Existing Rate with TY Adjusted Fuel [1]	Proposed Rate
Customer Charge ($/month)	0.00	250.00
Electric Delivery Charge ($/kW-billed)	n/a	2.50
Demand Charge ($/kW-billed) [2]		
Summer [3]	12.10	10.00
Non-summer [3]	11.11	9.00
Energy Charge (¢/kWh) [4]		
Summer [3]	4.831	4.127
Non-summer [3]	4.831	3.862
Energy Adjustment (¢/kWh) [5]	n/a	0.00
Community Benefit Charge [6]		
Customer Assistance Program (¢/kWh)	n/a	0.065
Service Area Street Lighting (¢/kWh)	n/a	0.066
Energy Efficiency Charge (¢/kWh)	n/a	0.174
Regulatory Charge ($/kW) [7]	n/a	2.28
Transmission Service Adjustment Rider ($/kW) [8]	0.24998	n/a
Percent Class Rate Change		1.2

Notes:
1. Represents the predominant rates currently effective for this customer class (Primary Service – E07). Other existing rates may be applicable to specific customers within this new proposed customer class.
2.-8. See Table 7.2.

Primary Voltage <3 MW Customer Electric Bill Impact Analysis

Figure 7.4 shows the impact of the proposed rates compared to current rates for all customers in the Primary Voltage <3 MW class. The graphic shows a monthly bill expressed on a $/kWh basis over a range of monthly load factors. The graphic provides a histogram that shows the number of customers within the Primary Voltage <3 MW class by load factor. The histogram indicates that the majority of customers in the this customer class have monthly load factors ranging from 40 percent to 90 percent.

Figure 7.4
Rate Design Results – Primary Voltage <3 MW
Current and Proposed Rates (in $/kWh): 820 kW Customer



The proposed rate structure aligns closely with the cost of service results cost curve and the current rate and the average rate would go down as the load factor increases. Primary Service (E07) customers will see moderate changes in their average rate. Those with a monthly load factor greater than 70 percent (24 percent of these customers) would receive a small decrease in their average rate while those with a load factor less than 70 percent (76 percent of these customers) would receive a small increase. Those in special contracts who are in this customer class will not see increases in their bill as they are locked in to their current rate by contract through May 2015, however at the expiration of those contracts they would receive a rate adjustment if priced at the proposed rate.

Primary Voltage <3 MW electric bill comparisons for each group of customers that will be placed in this class are shown in Tables 7.27 through 7.29. Please note that some existing customer classes, such as worship, will have customers distributed to multiple classes depending on the customer's service voltage and demand level. More extensive bill comparison data can be found in Appendix H. However, some bill comparison information for this customer class is not presented to protect the confidentiality of individual customers.

Table 7.27
Primary Service (E07) Rate Compared to Primary Voltage <3MW

Annual Average Monthly Electricity Bill (1)

	70% LF	80% LF	90% LF
Cumulative % of Bills	76	92	99
Current Bill ($)	29,758.49	32,650.27	35,542.04
Bill at Proposed Rates ($)	29,653.63	32,200.87	34,748.12
Dollar Increase ($)	(104.86)	(449.39)	(793.92)
Percent Increase (%)	0	-1	-2

Note:
1. Assumes a customer with a 820 kW monthly peak.

Table 7.28
Special Contract (LIR2/LIR3) Rate Compared to Primary Voltage <3MW

Annual Average Monthly Electricity Bill (1)

	70% LF	80% LF	90% LF
Current Bill ($)	27,022.50	29,515.21	32,007.93
Bill at Proposed Rates ($)	29,653.63	32,200.87	34,748.12
Dollar Increase ($)	2,631.13	2,685.66	2,740.19
Percent Increase (%)	10	9	9

Note:
1. Assumes a customer with a 820 kW monthly peak.

Table 7.29
Special Contract (LTC2/LTC3) Rate Compared to Primary Voltage <3MW

Annual Average Monthly Electricity Bill (1)

	70% LF	80% LF	90% LF
Current Bill ($)	27,285.98	29,781.77	32,277.57
Bill at Proposed Rates ($)	29,653.63	32,200.87	34,748.12
Dollar Increase ($)	2,367.65	2,419.10	2,470.54
Percent Increase (%)	9	8	8

Note:
1. Assumes a customer with a 820 kW monthly peak.

86 percent of the customers that will be placed in this customer class are currently in the Primary Service (E07) class. Primary Service (E07) customers not under contract placed in this customer class will generally see a slight decrease in their electric bills. Contract customers are about 10 percent below their cost of service, but will not receive a rate increase until the expiration of their contracts.

Proposed Standard Primary Voltage 3 MW – <20 MW Rate Structure and Prices

Table 7.30 compares the existing Primary Service Long-Term Contract (LTC2/LTC3) rates with the proposed Primary Voltage 3 – <20 MW rates as 41 percent of the customers in the proposed Primary Voltage 3 – <20 MW customer class are currently billed under the Primary Service Long-Term Contract (LTC2/LTC3) rates. Other existing customers included in this proposed customer class are Primary Service (E07) customers not in special contracts who receive service at the primary connection voltage level and whose maximum demand is 3 – <20 MW, State facilities (E17) who receive primary service and whose maximum demand for power is 3 – <20 MW (bill impact results not shown as the State recently renegotiated their rates), and certain other special contract (LIR2/LIR3) customers served at the primary service level whose maximum demand for power is 3 – <20 MW.

Table 7.30
Primary Voltage 3 MW - <20 MW
Existing Primary Service Long-Term Contract (LTC2/LTC3) Rate vs. Proposed Rate

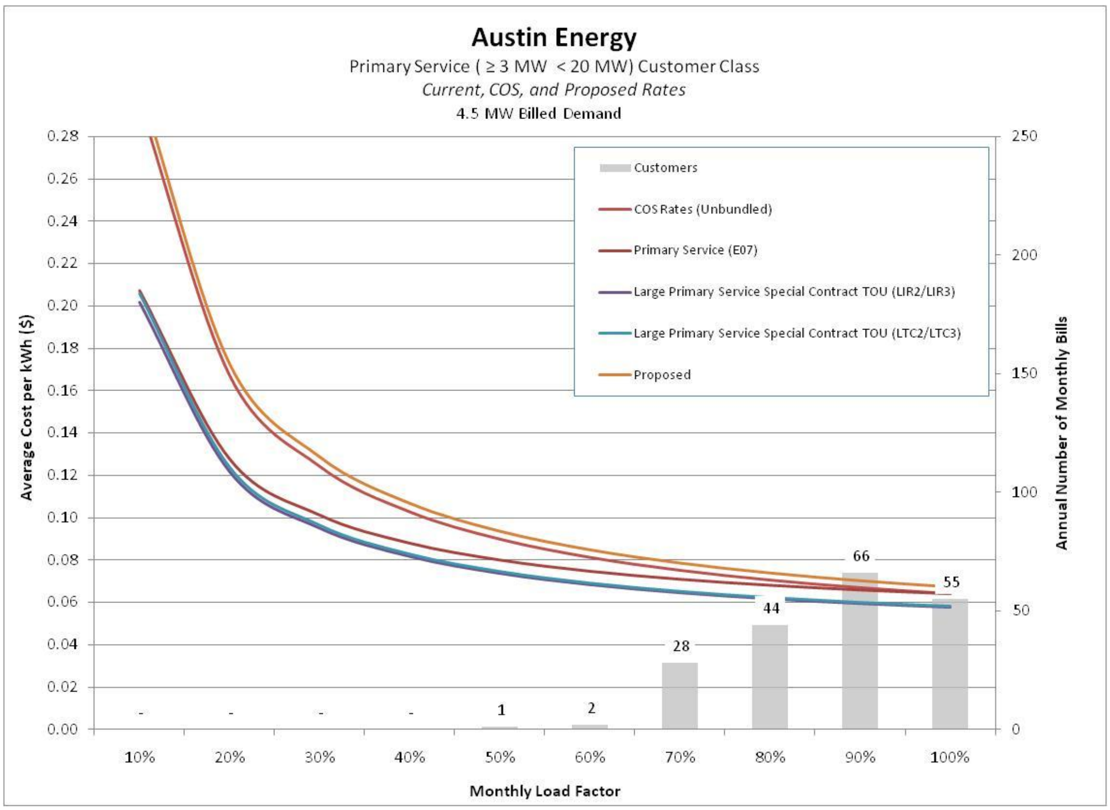
Name of Charge/Rate	Existing Rate with TY Adjusted Fuel (1)	Proposed Rate
Customer Charge ($/month)	0.00	2,000.00
Electric Delivery Charge ($/kW-billed)	n/a	3.50
Demand Charge ($/kW-billed) On-peak (2)		
Summer (3)	12.54	13.00
Non-summer (3)	11.40	12.00
Energy Charge (¢/kWh) On-peak (4)		
Summer (3)	5.731	4.004
Non-summer (3)	5.031	3.747
Energy Adjustment (¢/kWh) (5)	n/a	0.00
Community Benefit Charge (6)		
Customer Assistance Program (¢/kWh)	n/a	0.065
Service Area Street Lighting (¢/kWh)	n/a	0.062
Energy Efficiency Charge (¢/kWh)	n/a	0.162
Regulatory Charge ($/kW) (7)	n/a	2.93
Transmission Service Adjustment Rider ($/kW) (8)	0.00	n/a
Percent Class Rate Change		15.7

Notes:
1. Represents the predominant rates currently effective for this customer class (Primary Service Long-Term Contract – LTC2/LTC3. Other existing rates may be applicable to specific customers within this new proposed customer class.
2.-8. See Table 7.2.

Primary Voltage 3 – <20 MW Customer Electric Bill Impact Analysis

Figure 7.5 shows the impact of the proposed rate compared to current rates for all customers that would be placed in the Primary Voltage 3 – <20 MW class. The graphic shows a monthly bill expressed on a $/kWh basis over a range of monthly load factors. The graphic provides a histogram that shows the number of customers within the Primary Voltage 3 – <20 MW class by load factor. The histogram indicates that almost all customers in this class have monthly load factors ranging from 70 percent to over 90 percent.

Figure 7.5
Rate Design Results – Primary Voltage 3 MW - <20 MW
Current and Proposed Rates (in $/kWh): 4.5 MW Customer



The proposed rate structure aligns closely with the cost of service results cost curve and the average rate would go down as the load factor increases. Primary Service (E07) customers will see a small increase in their average rate. Those in special contracts who are in this customer class will not see increases in their bill as they are locked in to their current prices by contract through May 2015, however at the expiration of those contracts they would receive a rate increase if priced at the proposed rate.

Primary Voltage 3 – <20 MW electric bill comparisons for each group of customers that will be placed in this class are shown in Table 7.31 and Table 7.32. Please note that some existing customer classes, such as worship, will have customers distributed to multiple classes depending on the customer’s service voltage and demand level.

Bill comparisons for this class can be found in Appendix H. However, some bill comparison information for this customer class is not presented to protect the confidentiality of individual customers.

Table 7.31
Special Contract (LIR2/3) Rate Compared to Primary Voltage 3 - <20 MW (1)

Annual Average Monthly Electricity Bill (1)

	70% LF	80% LF	90% LF
Current Bill ($)	148,294.20	161,973.73	175,653.25
Bill at Proposed Rates ($)	181,212.73	194,752.40	208,292.08
Dollar Increase ($)	32,918.53	32,778.67	32,638.82
Percent Increase (%)	22	20	19

Note:
1. Assumes a customer with a 4,500 kW monthly peak.

Table 7.32
Special Contract (LTC2/3) Rate Compared to Primary Voltage 3 - <20 MW

Annual Average Monthly Electricity Bill (1)

	70% LF	80% LF	90% LF
Current Bill ($)	149,740.12	163,436.57	177,133.01
Bill at Proposed Rates ($)	181,212.73	194,752.40	208,292.08
Dollar Increase ($)	31,472.60	31,315.83	31,159.06
Percent Increase (%)	21	19	18

Note:
1. Assumes a customer with a 4,500 kW monthly peak.

All customers that will eventually be placed in this customer class are currently under special contract rates. These contract customers are about 20 percent below their cost of service, but will not receive a rate increase until the expiration of their contracts.

Proposed Standard Primary Voltage ≥20 MW Rate Structure and Prices

Table 7.33 compares the existing Primary Service Long-Term Contract (LIR2/LIR3) rates with the proposed Primary Voltage ≥20 MW rate as all of the customers in the proposed Primary Voltage ≥20 MW customer class are currently billed under the Primary Service Long-Term Contract (LIR2/LIR3) rate.

Table 7.33
Primary Voltage ≥20 MW Existing Rates vs. Proposed Rates

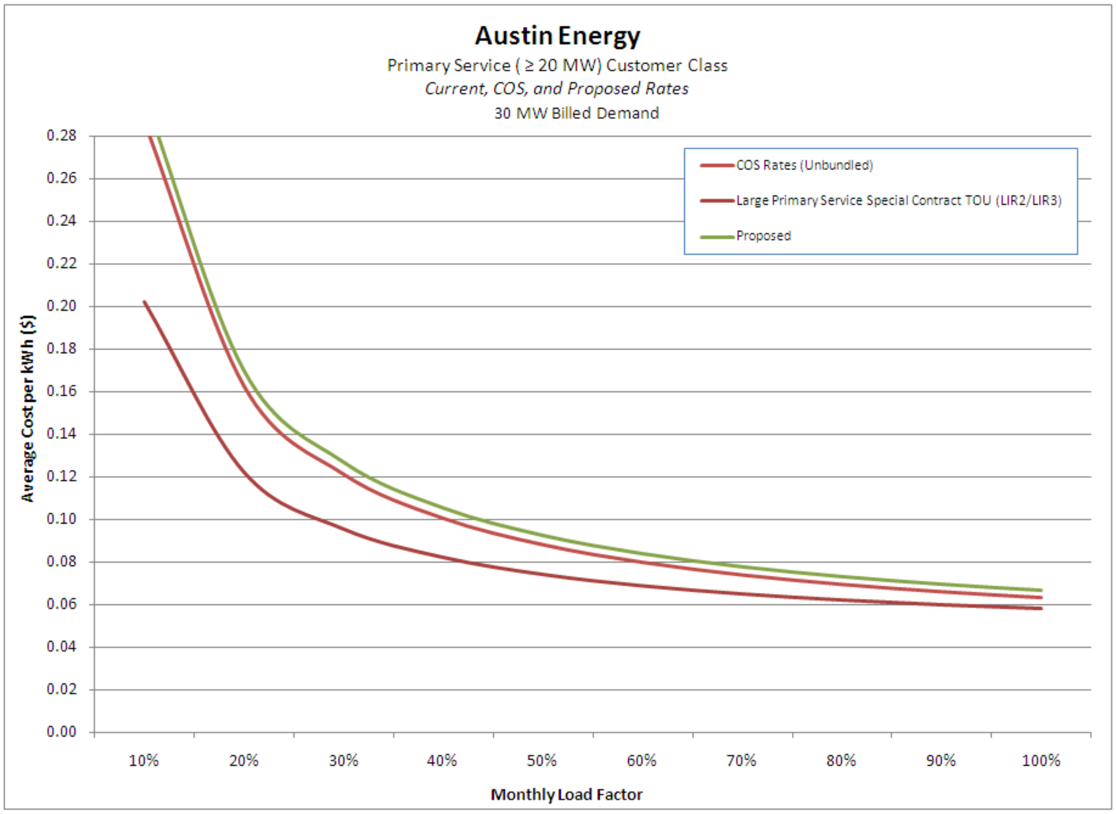
Name of Charge/Rate	Existing Rate with TY Adjusted Fuel (1)	Proposed Rate
Customer Charge ($/month)	0.00	2,500.00
Electric Delivery Charge ($/kW-billed)	n/a	3.50
Demand Charge ($/kW-billed) On-peak (2)		
Summer (3)	12.23	13.00
Non-summer (3)	11.12	12.00
Energy Charge (¢/kWh) (5)		
Summer On-Peak(3)	5.671	3.945
Summer Off-Peak(3)	3.871	3.945
Non-summer On-Peak(3)	4.991	3.692
Non-summer Off-Peak(3)	3.021	3.692
Energy Adjustment (¢/kWh) (5)	n/a	0.00
Community Benefit Charge(¢/kWh) (6)		
Customer Assistance Program (¢/kWh)	n/a	0.065
Service Area Street Lighting (¢/kWh)	n/a	0.059
Energy Efficiency Charge (¢/kWh)	n/a	0.156
Regulatory Charge ($/kW) (7)	n/a	2.92
Transmission Service Adjustment Rider ($/kW) (8)	0.00	n/a
Percent Class Rate Change		14.7

Notes:
1. Represents the predominant rates currently effective for this customer class (Primary Service Long Term Contract – LIR2/LIR3). Other existing rates may be applicable to specific customers within this new proposed customer class.
2.-8. See Table 7.2

Primary Voltage ≥20 MW Customer Electric Bill Impact Analysis

Figure 7.6 shows the impact of the proposed rate compared to current rate for all customers in the Primary Voltage ≥20 MW class. The graphic shows a monthly bill expressed on a $/kWh basis over a range of monthly load factors. Given that there are very few customers in this class, no histogram data was provided to protect the confidentiality of customer usage data.

Figure 7.6
Rate Design Results – Primary Voltage ≥20 MW
Current and Proposed Rates (in $/kWh): 30 MW Customer



The proposed rate structure aligns closely with the cost of service results cost curve and the average rate would go down as the load factor increases. All of the customers in this class are currently in special contracts. Therefore, these customers will not see increases in their bill as they are locked in to their current prices by contract through May 2015. However, at the expiration of those contracts they would receive an increase if priced at the proposed rate. Electric bill comparison information for this customer class is not presented to protect the confidentiality of individual customers.

Proposed Standard Transmission Voltage Rate Structure and Prices

Table 7.34 compares the existing Transmission Service Long-Term Contract (LIR2T) rates with the proposed Transmission Voltage rate.

Table 7.34
Transmission Voltage
Existing Transmission Service Long-Term Contract (LIR2T) Rate vs. Proposed Rate

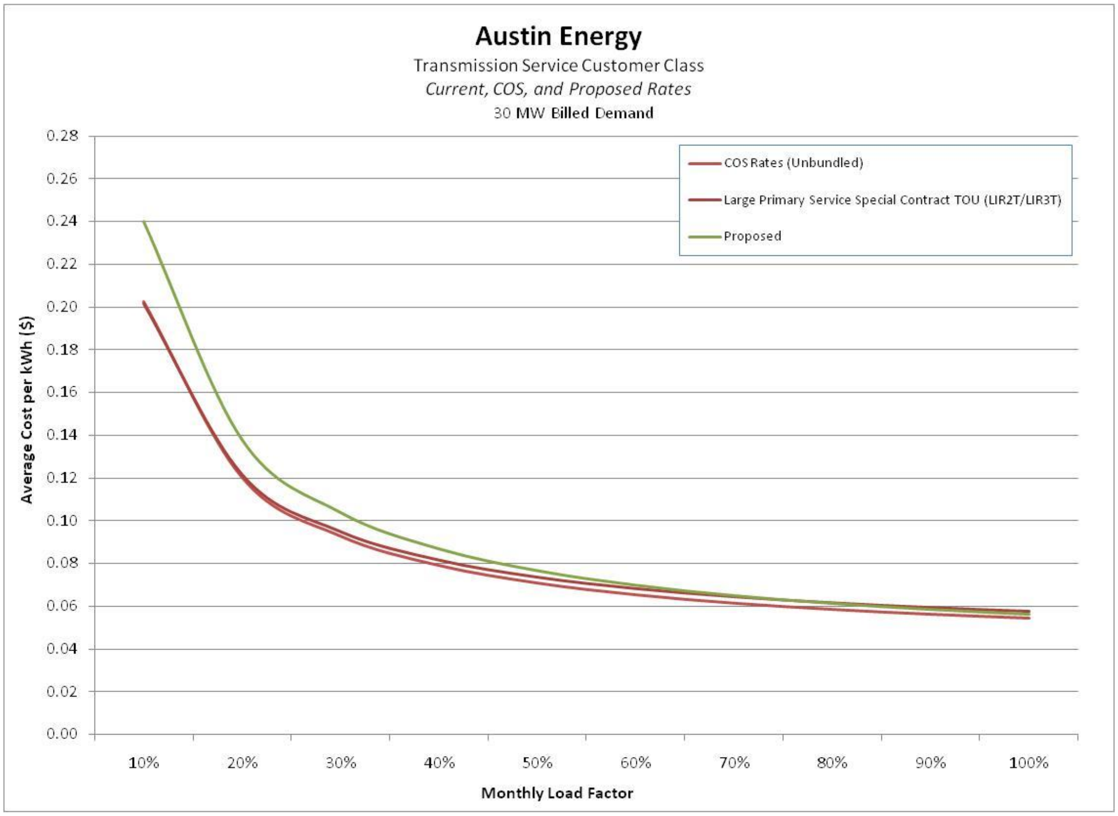
Name of Charge/Rate	Existing Rate with TY Adjusted Fuel (1)	Proposed Rate
Customer Charge ($/month)	0.00	2,500.00
Electric Delivery Charge ($/kW-billed)	n/a	n/a
Demand Charge ($/kW-billed) On-peak (2)		
Summer (3)	12.23	13.00
Non-summer (3)	11.12	12.00
Energy Charge (¢/kWh) (4)		
Summer On-Peak(3)	5.629	3.466
Summer Off-Peak(3)	3.829	3.466
Non-summer On-Peak(3)	4.949	3.243
Non-summer Off-Peak(3)	2.979	3.243
Energy Adjustment (¢/kWh) (5)	n/a	0.00
Community Benefit Charge (6)		
Customer Assistance Program (¢/kWh)	n/a	0.065
Service Area Street Lighting (¢/kWh)	n/a	0.053
Energy Efficiency Charge (¢/kWh)	n/a	0.139
Regulatory Charge (S/kW) (7)	n/a	2.49
Transmission Service Adjustment Rider ($/kW) (8)	0.00	n/a
Percent Class Rate Change		-5.3

Notes:
1. Represents the predominant rates currently effective for this customer class (Transmission Service Long- Term Contract – LIR2T). Other existing rates may be applicable to specific customers within this new proposed customer class.
2.-8. See Table 7.2.

Transmission Voltage Customer Electric Bill Impact Analysis

Figure 7.7 shows the impact of the proposed rates compared to current rates for all customers in the Transmission Voltage class. The graphic shows a monthly bill expressed on a $/kWh basis over a range of monthly load factors. Given that there are very few customers in this class, no histogram data was provided to protect the confidentiality of customer usage data.

Figure 7.7
Rate Design Results – Transmission Voltage
Current and Proposed Rates (in $/kWh): 30 MW Customer



The proposed rate structure aligns closely with the cost of service results cost curve and the average rate would go down as the load factor increases. Customers in this class that are currently served under the terms of a special contract will not see an increase in their bill until after May 2015. However at the expiration of this special contract it will receive the increase indicated at the proposed rates for load factors below approximately 80 percent. To protect the confidentiality of individual customers, Transmission Service bill comparison information is not presented.

Proposed Commercial and Industrial Rate Alternatives

Rate alternatives for commercial and industrial customers proposed by AE in this rate review include the continuation of a renewable pricing option that allows customers to receive 100 percent renewable energy (with some revisions to the program structure), the continuation of a net metering rate that supports customer adoption of solar PV systems (with a minor revision to the design), the continuation of a thermal energy storage rate option for customers who adopt that technology (with a minor revision to the design), and implementation of TOU rates for each customer class intended to help customers and the utility save money if they lower their demand during peak time periods (when energy costs are higher) or shifting their demand from on-peak (when energy costs are higher) to off-peak periods (when energy costs are lower).

GreenChoice® Renewable Energy Alternative Rate

Austin Energy's GreenChoice® program is the nation's most successful utility-sponsored, voluntary renewable energy pricing program, based on aggregate sales. Austin Energy commercial and industrial customers can currently receive 100 percent renewable energy by enrolling in the utility's GreenChoice program and paying a renewable energy rate in lieu of the fuel adjustment clause. The GreenChoice rate represents the actual contract cost, estimated congestion costs, and administrative costs for renewable energy purchased by AE. Customers currently participate in the GreenChoice program by subscribing to a specific "batch" that locks-in the renewable energy rate for the length of the contract (typically around 10 years). To date, six batches have been developed and the first two batches expired in March 2011. Austin Energy is proposing improvements to the structure of its GreenChoice program with the objective of remaining a leader in renewable energy sales and meeting customer demand.

Most commercial and industrial customers currently have the option to meet all or a portion of their electricity needs with renewable energy resources. Austin Energy is proposing a change to this policy in that new GreenChoice subscribers must purchase 100 percent renewable energy <u>for each billed customer meter</u>. This allows even the largest customers the opportunity to provide for at least some portion of their electricity to be based on renewable sources.

Commercial and industrial customers currently subscribed to GreenChoice will continue to receive their locked-in renewable energy rate and fuel costs embedded in the proposed energy charge will be removed from their electric bills. Additionally, current GreenChoice customers will not have any fuel portion of future energy adjustments applied to their bills during the term of their contract. In other words, current GreenChoice customers will see no change on their bill with regard to fuel costs even after new rates are implemented until the GreenChoice batch they are subscribed to expires. The application of all non-fuel-related charges will be the same for GreenChoice customers as with other customers. As existing GreenChoice customer contracts expire, customers will have the option to subscribe to the new adopted GreenChoice rate or their adopted standard rate.

The proposed new GreenChoice program structure will continue to allow customers to lock-in a fixed price for receiving 100 percent renewable energy in lieu of the fuel charges embedded in the energy charge and any future energy adjustments over the term period established for each annual offering. All other charges are applicable in the same manner as with other customers in their customer class. The primary GreenChoice program design change proposed by AE is a move from a "batch" pricing approach in which the offered price is tied to a specific renewable resource contract to a portfolio-based pricing approach in which renewable energy is added to the GreenChoice portfolio inventory to determine the GreenChoice price. This will allow AE to develop annual price offerings for GreenChoice based on the utility's entire renewable resource portfolio as the utility pursues its renewable generation goals on a system-wide basis. This will increase the utility's flexibility in developing the GreenChoice offer price. This GreenChoice price as well as the adjustment which will be applied to customer electric bills will be calculated annually. The current proposal envisions sales under the new program to begin April 1, 2012 and January 1 each year thereafter. Therefore, GreenChoice will be subscribed to on the basis of individual annual offerings and identified in terms of year; for example, GC2012 for subscriptions based on the offering in 2012, GC2013 for 2013, and so on.

An additional change to the GreenChoice pricing structure is that GreenChoice subscribers will now receive credit for the amount of un-subscribed renewable energy that is shared among all customers. As with the current program structure, if the program is not fully subscribed the costs of unsold renewable energy secured by AE will be spread among all other customers. For example, if 90 percent of the renewable energy allocated to the program is subscribed under GreenChoice, 10 percent of the costs associated with renewable energy must be passed on to all other customers. Therefore, all other customers will receive a certain portion of their electricity from renewable resources. Since GreenChoice subscribers could have received a percentage of their energy from renewable resources regardless of their participation in GreenChoice, AE is proposing that GreenChoice customers receive a credit for the amount of renewable energy they would have received under the customer's standard electric rate.

Consistent with current practice, the GreenChoice price consists of components that will be fixed during the length of term established and tied to each annual product offering. The fixed GreenChoice price is based on two components: 1) cost of the renewable supply, including transmission and delivery costs, and any applicable ERCOT charges; and 2) administrative, marketing, and general revenue costs associated with the program. This price will not change during the life of the subscription. However, given that fuel charges are now embedded in the energy rate, treatment of GreenChoice subscribers from a billing standpoint is somewhat different from current practice. Subscriber bills will be subject to a "GreenChoice Adjustment" which is the result of a calculation that takes into account: (1) the fixed GreenChoice price, (2) subtraction of any charges related to fuel, and (3) proration to exclude any system renewable energy not allocated to other GreenChoice subscribers. The GreenChoice adjustment is calculated based on the following formula:

GreenChoice Adjustment = GreenChoice Price – Fuel Charges * SRS Adjustment (see below)

Where GreenChoice Price is the fixed charge established at the time of subscription, *Fuel Charges* are any costs associated with fuel used in non-renewable electricity production, and the *SRS Adjustment Factor* (explained below) is a percentage (0%-100%) which takes into account the difference between System Renewable Energy as described below and energy allocated to GreenChoice subscriptions.

The System Renewable Supply Adjustment Factor ("SRS") is expressed as a percentage and is defined as 100 minus the difference between *Community Supply* and *GreenChoice Supply*.

Community Supply ("CS") is defined as any energy produced from all renewable energy sources which are owned and operated by AE and/or interconnected to the AE electric distribution system and metered, including customer-owned generation, city-owned generation, AE-owned generation not allocated to the GreenChoice program, and renewable energy associated with GreenChoice subscriptions. Community Supply is expressed as a percentage of total retail sales to AE customers and calculated on an annual basis.

GreenChoice Supply (GS) is defined as energy attributable to GreenChoice customer subscriptions, including subscriptions initiated before April 1, 2012, expressed as a percentage of total retail sales to AE customers and calculated on an annual basis.

The formula for determining the GreenChoice adjustment on a monthly basis, including the SRS adjustment is as follows:

GreenChoice Price	GCP_1	(¢/kWh)
Fuel Charges	FC	(¢/kWh)
Subtotal (GCP_1-FC)	GCP_2	(¢/kWh)

SRS% = 100% – [Community Supply (CS) % - GreenChoice Supply (GS) %]

GreenChoice Adjustment (¢/kWh) = (GCP_2 X SRS) x Monthly Consumption (kWh)

The GreenChoice adjustment may change on an annual basis as any fuel-related adjustments are incurred or there are changes in either Community Supply or GreenChoice Supply, but customers should note the fixed cost established at the time of their subscription will remain so for their term.

An example of the GreenChoice adjustment calculation is provided as Table 7.35 for a hypothetical small commercial secondary voltage customer using 1,000 kWh per month. Please note that the numbers assumed in this example are for illustrative purposes only as actual numbers may vary from this example.

Table 7.35
Hypothetical Proposed GreenChoice® Calculation Under Proposed Rates for Small Commercial Customer Consuming 1,000 kWh per Month

GreenChoice® Price	GCP_1	= 20.0 ¢/kWh
Fuel Charges	FC	= 10.0 ¢/kWh
Subtotal (GCP_1 – FC)	GCP_2	= 20.0 ¢/kWh – 10.0 ¢/kWh
		= 10.0 ¢/kWh

System Green Power Produced/Purchased = 10,000,000 MWh/Year

Green Power Subscribed = 5,000,000 MWh/Year

Total Energy Produced/Purchased = 100,000,000 MWh/Year

Community Supply (CS)	= 10,000,000 MWh / 100,000,000 MWh
	= 10%
GreenChoice® Supply (GS)	= 5,000,000 MWh/100,000,000 MWh
	= 5%
SRS Adjustment	= 100% – [10% – 5%]
	= 100% – 5%
	= 95%
GreenChoice® Adjustment	= (10 ¢/kWh * 95%) * 1,000 kWh
	= $95

Net Metering Distributed Generation Alternative Rate

Commercial and industrial customers can also currently receive credit on their electric bill for producing electricity from distributed generation systems such as solar PV by participating in the utility's net metering rate. Austin Energy is making one substantive change to its net metering rate by proposing to apply a credit at a determined value of solar amount for any excess energy generated on a monthly basis rather than crediting excess generation at the utility's fuel rate. It is the utility's intention to continue to evaluate other options for pricing solar PV to support the utility's strategic objectives of supporting 200 MW of solar by 2020. The utility intends to move to a separate solar rate when meter data management capabilities are achieved.

The net metering rate option is designed for customers who have installed a solar PV system or other renewable distributed generation system on their customer premise for up to 20 kW of production that is interconnected with AE's electric system. This rate is designed to fairly compensate these customers for their generation of emissions-free, local, grid-tied electricity while still charging the customers for the electricity they consume. Net metering is designed to charge a customer for their monthly net energy consumption (i.e., total energy taken from the grid less any energy provided back to the grid). If a customer provides more energy back to AE than it consumes from the grid in a given month, the customer is currently credited at AE's existing fuel rate. Under the proposed new net metering rate, the same net metering calculation will apply, but the customer will receive credit for the excess electricity produced (over consumption for any month) at a calculated annual value of solar rate.

The credit provided to a customer's monthly electric bill is calculated using a value of solar algorithm developed in 2006 in a study commissioned by the utility and updated annually. This calculation takes into consideration the value of the energy produced based upon the marginal costs of the displaced energy, the avoided capital cost of installing new power generation due to the added capacity of the solar PV system, transmission and distribution expense and line loss savings associated with the system, and environmental benefits. The credit would be adjusted annually to account for market value changes and other factors that influence the value of the solar energy generated. As shown in Table 7.36, from 2006 through 2011 the value of solar has fluctuated from 9.9 cents per kWh to 16.4 cents per kWh dependent on the type of system installed (i.e., fixed versus tracking system). In 2011, this algorithm resulted in a 12.6 cents per kWh value for solar.

Table 7.36
Value of Solar By Year

Year	System Type	Average Value (cents/kWh)
2006	Fixed	10.3
2007	Fixed	11.8
2008	Fixed	16.4
2009	Fixed	13.8
2011	Fixed	12.6
2006	Track	9.9
2007	Track	11.4
2008	Track	15.8
2009	Track	14.1
2011	Track	12.8

Commercial and Industrial Time-of-Use Alternative Rates

Similar to the residential TOU rate option discussed in Section 6 of this report, AE plans to offer TOU alternative rates for each commercial and industrial customer class. These TOU alternative rates are designed to better reflect cost of service variations in AE's production costs (seasonally and at various times of the day), to provide incentives for non-residential customers to reduce energy usage at the time of AE's peak demand, and to shift electricity usage to times when AE's production is more efficient and costs are lower. If successful, these TOU rates will incentivize non-residential customers to reduce their coincident peak demand on the AE system and to realize cost savings from reducing or shifting their electricity usage to off-peak periods.

The methodology used to develop cost of service-based TOU rates for commercial and industrial customers is similar to that described in Section 6 of this report for the residential TOU alternative rate. Austin Energy's TY generation costing data were used to separate operating costs into base demand costs, intermediate demand costs, and peak demand costs. For each non-residential class, unit costs were determined for on-peak demand and energy charges, intermediate peak demand and energy charges, and off-peak peak demand and energy charges using the four-month summer rate period (June 1-through September 30) and the remaining eight-month non-summer rate period.

The TOU rates reflect average system line losses at different service voltages and the corresponding peak, intermediate, and off-peak energy costs. For secondary voltage customers, a portion of demand costs are recovered through a monthly on-peak billed demand charge during the summer months. There would be no charge for customer demand during the intermediate and off-peak periods. For primary and transmission voltage customers, a portion of demand costs are recovered through monthly on-peak billed demand during the summer months and monthly intermediate peak billed demand during the non-summer months.

Minor adjustments to the demand rates were made to account for an estimated 5 percent demand response for TOU charged non-residential usage in order that customers with TOU rates would still provide the same target revenue as other similar customers. This is an assumption made in the design of TOU rates that needs to be reassessed by AE in the future. The proposed non-residential TOU rate structures are summarized in Table 7.37 and Table 7.38.

Table 7.37
Secondary Voltage Time-of-Use Alternative Rate

	Secondary Service (<10 kW)	Secondary Service (10 - <50 kW)	Secondary Service (≥50 kW)
Customer Charge ($/month)	21.60	30.00	68.25
Electric Delivery ($/kW-billed)	2.50	4.00	4.00
Demand Charge ($/kW-billed)			
On Peak ($/kW) (1)	4.07	6.72	8.39
Mid Peak ($/kW) (2)	0	0	0
Off Peak ($/kW) (3)	0	0	0
Energy Charge (¢/kWh)			
Summer			
On-Peak (¢/kWh) (1)	11.840	10.625	9.950
Mid-Peak (¢/kWh) (2)	8.520	7.646	7.160
Off-Peak (¢/kWh) (3)	3.943	3.539	3.313
Non-summer			
On-Peak (¢/kWh) (1)			
Mid-Peak (¢/kWh) (2)	8.520	7.646	7.160
Off-Peak (¢/kWh) (3)	3.943	3.539	3.313
Energy Adjustment (¢/kWh) (4)			
Community Benefit Charge (5)			
Customer Assistance Program (¢/kWh)	0.065	0.065	0.065
Service Area Street Lighting (¢/kWh)	0.113	0.088	0.078
Energy Efficiency Charge (¢/kWh)	0.296	0.231	0.206
Regulatory Charge ($/kW) (6)	2.33	2.44	2.57

Notes:
1. The on-peak time period is Monday–Friday from 2:00 p.m. – 8:00 p.m. during the months of June-September.
2. The mid-peak period is all hours not included in the on-peak or off-peak periods.
3. The off-peak period is every day from 10:00 p.m. – 6:00 a.m.
4. The Energy Adjustment is a new charge that replaces the current Fuel Adjustment Clause. The Energy Adjustment is set to zero but is subject to change as described in Section 5 of this report.
5. The Community Benefit Charge is a new charge that funds three specific programs and services provided to the community by AE. The Customer Assistance Program creates monies to provide discounts to qualified low-income and other disadvantaged customers. Service Area Lighting recovers the cost of street lighting to customers within the entire AE service territory. Energy efficiency recovers the cost of energy efficiency, green building, and solar rebate programs offered by AE.
6. The Regulatory Charge is a new charge that replaces the Transmission Service Adjustment Rider and includes ERCOT administration fees and charges associated with AE's cost of ERCOT transmission.

Table 7.38
Primary Voltage Time-of-Use Alternative Rate

	Primary Service (<3 MW)	Primary Service (3 – <20 MW)	Primary Service (≥20 MW)
Customer Charge ($/month)	262.50	2,000.00	2,500.00
Electric Delivery ($/kW-billed)	2.50	3.50	3.50
Demand Charge ($/kW-billed)			
On Peak ($/kW) (1)	13.69	13.77	13.70
Mid Peak ($/kW) (2)	12.29	12.37	12.30
Off Peak ($/kW) (3)	0.00	0.00	0.00
Energy Charge (¢/kWh)			
Summer			
On-Peak (¢/kWh) (1)	5.150	5.150	5.150
Mid-Peak (¢/kWh) (2)	3.706	3.706	3.706
Off-Peak (¢/kWh) (3)	1.715	1.715	1.715
Non-summer			
On-Peak (¢/kWh) (1)	n/a	n/a	n/a
Mid-Peak (¢/kWh) (2)	3.706	3.706	3.706
Off-Peak (¢/kWh) (3)	1.715	1.715	1.715
Energy Adjustment (¢/kWh) (4)	0.00	0.00	0.00
Community Benefit Charge (5)			
Customer Assistance Program (¢/kWh)	0.065	0.065	0.065
Service Area Street Lighting (¢/kWh)	0.066	0.062	0.059
Energy Efficiency Charge (¢/kWh)	0.174	0.162	0.156
Regulatory Charge ($/kW) (6)	2.28	2.93	2.92

Notes:
1. The on-peak time period is Monday–Friday from 2:00 p.m. – 8:00 p.m. during the months of June-September.
2. The mid-peak period is all hours not included in the on-peak or off-peak periods.
3. The off-peak period is every day from 10:00 p.m. – 6:00 a.m.
4. The Energy Adjustment is a new charge that replaces the current Fuel Adjustment Clause. The Energy Adjustment is set to zero but is subject to change as described in Section 5 of this report.
5. The Community Benefit Charge is a new charge that funds three specific programs and services provided to the community by AE. The Customer Assistance Program creates monies to provide discounts to qualified low-income and other disadvantaged customers. Service Area Lighting recovers the cost of street lighting to customers within the entire AE service territory. Energy efficiency recovers the cost of energy efficiency, green building, and solar rebate programs offered by AE.
6. The Regulatory Charge is a new charge that replaces the Transmission Service Adjustment Rider and includes ERCOT administration fees and charges associated with AE's cost of ERCOT transmission.

Table 7.39
Transmission Voltage Time-of-Use Alternative Rate

	Transmission Voltage
Customer Charge ($/month)	2,500.00
Electric Delivery ($/kW-billed)	n/a
Demand Charge ($/kW-billed)	
On-Peak ($/kW) (1)	12.48
Mid-Peak ($/kW) (2)	11.08
Off-Peak ($/kW) (3)	0.00
Energy Charge (¢/kWh)	
Summer	
On-Peak (¢/kWh) (1)	5.084
Mid-Peak (¢/kWh) (2)	3.659
Off-Peak (¢/kWh) (3)	1.693
Non-summer	
On-Peak (¢/kWh) (1)	n/a
Mid-Peak (¢/kWh) (2)	3.659
Off-Peak (¢/kWh) (3)	1.693
Energy Adjustment (¢/kWh) (4)	0.00
Community Benefit Charge (5)	
Customer Assistance Program (¢/kWh)	0.065
Service Area Street Lighting (¢/kWh)	0.053
Energy Efficiency Charge (¢/kWh)	0.139
Regulatory Charge ($/kW) (6)	2.49

Notes:
1. The on-peak time period is Monday–Friday from 2:00 p.m. – 8:00 p.m. during the months of June-September.
2. The mid-peak period is all hours not included in the on-peak or off-peak periods.
3. The off-peak period is every day from 10:00 p.m. – 6:00 a.m.
4. The Energy Adjustment is a new charge that replaces the current Fuel Adjustment Clause. The Energy Adjustment is set to zero but is subject to change as described in Section 5 of this report.
5. The Community Benefit Charge is a new charge that funds three specific programs and services provided to the community by AE. The Customer Assistance Program creates monies to provide discounts to qualified low-income and other disadvantaged customers. Service Area Lighting recovers the cost of street lighting to customers within the entire AE service territory. Energy efficiency recovers the cost of energy efficiency, green building, and solar rebate programs offered by AE.
6. The Regulatory Charge is a new charge that replaces the Transmission Service Adjustment Rider and includes ERCOT administration fees and charges associated with AE's cost of ERCOT transmission.

Bill Impact Analysis for Commercial and Industrial TOU Rate Alternatives

Bill impacts associated with TOU rates are highly variable and specific to individual customer load characteristics. Time-of-use rates are designed to reward off-peak usage and may result in a lower monthly power bills. A customer's time of peak demand and monthly load factor are the two primary determinates of the TOU bill.

Due to the energy charge component of the TOU rate, even if a customer's usage is largely off-peak (meaning that a customer's maximum demand on the system occurs during mid-peak or off-peak periods), a high monthly load may offset any savings realized by operating during predominately non-on-peak hours. High load factor customers use energy in all pricing periods. This energy usage, particularly during on-peak and mid-peak periods may offset any peak demand savings. To illustrate the impact of TOU rates on monthly electric bills, we offer the following examples for each of the secondary, primary, and transmission voltage customer classes.

Secondary Voltage

To understand the impact of TOU rates on secondary voltage customers, a sample of actual AE customers was reviewed comprising of worship facilities, schools, and general service commercial customers. Customers that have peak demands during mid-peak or off-peak periods were selected for the billing comparison analysis. For a 12-month period, actual bills were calculated for each customer under the applicable proposed secondary voltage rate and the alternative applicable secondary voltage TOU rate for each customer class. The results of this analysis are provided in Table 7.40.

Table 7.40
Sample Secondary Voltage Customers TOU Rate Compared to Proposed Standard Rate

Existing Customer Class Code	Proposed Customer Class	Summer Mid-Peak (kW)	Summer On-Peak (kW)	Proposed Standard Rate – Average Monthly Bill ($)	Proposed TOU Rate -Average Monthly Bill ($)	Diff ($)	Diff (%)
E01C	Secondary Voltage (< 10 kW)	4.91	4.66	85.41	81.51	-3.90	-4.57
E02	Secondary Voltage (< 10 kW)	1.81	1.80	127.19	130.42	3.23	2.54
E02	Secondary Voltage (< 10 kW)	13.46	12.07	259.03	263.40	4.37	1.69
E01C	Secondary Voltage (≥ 10 < 50 kW)	22.77	21.29	346.62	275.92	-70.69	-20.40
E01C	Secondary Voltage (≥ 10 < 50 kW)	22.28	21.68	308.54	290.01	-18.53	-6.01
E01C	Secondary Voltage (≥ 10 < 50 kW)	15.47	15.20	211.77	198.22	-13.55	-6.40
E01C	Secondary Voltage (≥ 10 < 50 kW)	13.13	14.21	220.41	228.44	8.02	3.64
E02	Secondary Voltage (≥ 10 < 50 kW)	12.13	12.07	659.34	687.37	28.03	4.25
E02	Secondary Voltage (≥ 10 < 50 kW)	17.19	17.51	434.07	434.09	0.02	0.00
E10	Secondary Voltage (≥ 10 < 50 kW)	23.09	9.74	627.76	586.34	-41.42	-6.60
E10	Secondary Voltage (≥ 10 < 50 kW)	47.06	50.94	1,229.61	1,229.06	-0.54	-0.04
E04	Secondary Voltage (≥ 10 < 50 kW)	13.00	5.93	137.99	139.68	1.70	1.23
E01C	Secondary Voltage (≥ 50 kW)	125.82	127.94	2,239.00	2,211.39	-27.61	-1.23
E07S	Secondary Voltage (≥ 50 kW)	677.18	666.83	25,564.91	27,143.95	1,579.04	6.18
E06	Secondary Voltage (≥ 50 kW)	49.71	37.86	1,478.50	1,399.96	-78.55	-5.31
E06	Secondary Voltage (≥ 50 kW)	577.50	522.50	22,626.14	23,600.25	974.11	4.31
E06	Secondary Voltage (≥ 50 kW)	183.10	176.70	6,689.16	6,937.75	248.59	3.72
E06	Secondary Voltage (≥ 50 kW)	514.10	515.30	18,896.07	19,522.81	626.74	3.32
E06	Secondary Voltage (≥ 50 kW)	54.00	52.77	2,079.27	2,183.65	104.39	5.02
E06	Secondary Voltage (≥ 50 kW)	96.00	81.05	3,219.83	3,182.02	-37.81	-1.17
E23NP	Secondary Voltage (≥ 50 kW)	567.72	560.12	12,043.02	12,032.27	-10.75	-0.09

The sample in Table 7.40 indicates that the average monthly electric bill under the TOU rates structure will be less than under the standard rates for more than one-half (½) of the sample (13 of 20 customers). Generally, customers receiving the largest bill decreases are customers whose usage is primarily off-peak with low load factors.

Customers who receive the largest bill increases tend to have little to no on-peak demand reduction and high monthly load factors. To the extent that any of these customers could shift power usage to off-peak periods beyond that shown in Table 7.41, additional reductions in their TOU electric bill could be achieved. To illustrate this point, we have assumed that the above list of customers could reduce usage during the on-peak period by 15 percent by shifting their on-peak energy usage to mid-peak and off-peak periods. Such a shift results in additional saving as shown in Table 7.41.

Table 7.41
Sample Secondary Voltage Customers TOU Rate Compared to Proposed Standard Rate with 15% On-Peak Demand Reduction

Proposed Customer Class	Summer Mid Peak (kW)	Summer On Peak (kW)	Proposed Standard Rate – Average Monthly Bill($)	Proposed TOU Rate -Average Monthly Bill ($)	Difference ($)	Percentage Difference (%)
Secondary Voltage (< 10 kW)	4.91	3.96	85.38	80.43	-4.95	-5.80
Secondary Voltage (< 10 kW)	1.81	1.53	127.14	129.64	2.50	1.97
Secondary Voltage (< 10 kW)	13.46	10.26	258.40	259.44	1.04	0.40
Secondary Voltage (≥ 10 < 50 kW)	22.77	18.10	345.27	268.75	-76.51	-22.16
Secondary Voltage (≥ 10 < 50 kW)	22.28	18.43	303.71	279.54	-24.18	-7.96
Secondary Voltage (≥ 10 < 50 kW)	15.47	12.92	210.21	192.56	-17.65	-8.40
Secondary Voltage (≥ 10 < 50 kW)	13.13	12.08	217.06	221.51	4.45	2.05
Secondary Voltage (≥ 10 < 50 kW)	12.13	10.26	658.33	680.80	22.47	3.41
Secondary Voltage (≥ 10 < 50 kW)	17.19	14.88	431.02	425.40	-5.62	-1.30
Secondary Voltage (≥ 10 < 50 kW)	23.09	8.28	627.76	582.10	-45.65	-7.27
Secondary Voltage (≥ 10 < 50 kW)	47.06	43.30	1,220.43	1,203.80	-16.63	-1.36
Secondary Voltage (≥ 10 < 50 kW)	13.00	5.04	137.97	138.20	0.23	0.17
Secondary Voltage (≥ 50 kW)	125.82	108.75	2,232.42	2,158.95	-73.48	-3.29
Secondary Voltage (≥ 50 kW)	677.18	566.80	25,554.92	26,754.59	1,199.67	4.69
Secondary Voltage (≥ 50 kW)	49.71	32.18	1,477.16	1,379.21	-97.94	-6.63
Secondary Voltage (≥ 50 kW)	577.50	444.13	22,622.75	23,299.88	677.13	2.99
Secondary Voltage (≥ 50 kW)	183.10	150.20	6,683.89	6,837.08	153.19	2.29
Secondary Voltage (≥ 50 kW)	514.10	438.01	18,878.74	19,234.83	356.09	1.89
Secondary Voltage (≥ 50 kW)	54.00	44.85	2,079.27	2,157.36	78.09	3.76
Secondary Voltage (≥ 50 kW)	96.00	68.90	3,217.28	3,141.13	-76.15	-2.37
Secondary Voltage (≥ 50 kW)	567.72	476.10	12,043.02	11,799.25	-243.77	-2.02

The sample in Table 7.41 indicates that the average monthly electric bill under the TOU rate structure will be less than under the standard rates for 14 of 20 customers.

In total, a 15 percent load shift to mid-peak and off-peak time periods results in an average additional reduction in power bills of about 1.5 percent.

Primary and Transmission Voltage

Customers served at primary and transmission voltage are much larger and have very high monthly load factors compared to secondary voltage customers. As a result, the TOU rate structure has demand charges in the on-peak and mid-peak time periods. These demand charges are higher than those proposed for secondary voltage customers. Therefore, the proposed primary and transmission voltage TOU rates reward high load factor and off-peak shifting. Unfortunately, high load factor customers use power all the time, therefore, these customers may not be able to shift on-peak demand and usage to mid-peak or off-peak time periods. The TOU rate compared to the standard rate for sample customers is shown in Table 7.42.

Table 7.42
Sample Primary and Transmission Voltage Customers TOU Rate Compared to Proposed Standard Rate

Proposed Customer Class	Summer Mid Peak (kW)	Summer On Peak (kW)	Proposed Standard Rate – Average Monthly Bill ($)	Proposed TOU Rate - Average Monthly Bill ($)	Diff ($)	Diff (%)
Primary Voltage <3 MW	2,000	2,000	71,966	70,997	-969	-1.35
Primary Voltage 3 - <20 MW	10,000	9,832	430,339	393,829	-36,510	-8.48
Primary Voltage ≥20 MW	25,000	25,000	1,137,586	1,042,852	-94,734	-8.33
Transmission Voltage	25,000	25,000	959,720	895,877	-63,843	-6.65

Even in the absence of load shifting, high load factor customers are rewarded with lower electric bills under the TOU rate structure. Because high load factor customers use power all of the time, they benefit from lower electric costs during the mid-peak and off-peak pricing periods. As described in Section 6 of this report, the majority of hours in the year are either mid-peak or off-peak. In addition to this immediate reduction in power costs, the TOU pricing structure also incentivizes these customers to shift load to mid-peak and off-peak periods. To illustrate this point, we have assumed that the above list of customers could reduce usage during the on-peak period by 15 percent and shift on-peak energy usage to mid-peak and off-peak periods. Such a shift results in additional saving as shown in Table 7.43.

Table 7.43
Sample Primary and Transmission Voltage Customers TOU Rate Compared to Proposed Standard Rate with 15% On Peak Demand Reduction

Proposed Customer Class (a)	Summer Mid Peak (kW)	Summer On Peak (kW)	Proposed Standard Rate – Average Monthly Bill ($)	Proposed TOU Rate - Average Monthly Bill ($)	Diff ($)	Diff (%)
Primary Voltage <3 MW	2,000	1,700	71,914	69,612	-2,301	-3.20
Primary Voltage 3 - <20 MW	10,000	8,357	430,339	387,131	-43,208	-10.04
Primary Voltage ≥20 MW	25,000	21,250	1,136,134	1,025,247	-110,887	-9.76
Transmission Voltage	25,000	21,250	959,692	880,912	-78,780	-8.21

Savings under the TOU rate associated with peak shifting compared to the standard applicable rate range from less than 3 percent (2.7 percent) to 10 percent (9.7 percent). The savings associated with the average electric bill for customers that shift on-peak demand by 15 percent to either mid-peak and off-peak periods is an additional 2 percent compared to TOU electric bills with no peak shifting.

As the commercial and industrial TOU rates are based on calculations that necessarily reflect a number of assumptions and preliminary estimates, AE is initially offering these rates to a limited number of participants with an enrollment cap of the higher of 10 percent of the customers in the class or 10 customers for each class. Once more research and information is gathered, AE will consider expansion or modification of these TOU rate design alternatives.

Thermal Energy Storage Alternative Rate

Austin Energy currently offers a thermal energy storage TOU pricing structure to commercial and industrial customers who have installed thermal energy storage technology on the customer's premise. Customers served under this rate structure must shift to off-peak time periods at least 20 percent of their normal on-peak summer demand or 2,500 kW through the use of thermal energy storage technology. As discussed in the above section on TOU pricing, shifting energy usage from on-peak to off-peak time periods achieves cost savings for the utility. Thermal energy storage technologies effectively store energy during off-peak periods for use during on-peak periods. Various technologies currently exist that achieve this goal. The most common application of thermal energy storage technology in Texas is to shift the production of energy for cooling loads (i.e., air conditioning usage) from on-peak to off-peak time periods. This is typically achieved by producing ice, chilled water, or another solution at night and then using that product to cool building environments during the day.

Investing in thermal energy storage technology can produce cost savings to the customer. However, a TOU pricing structure is necessary to maximize the economic benefit to these customers and thereby promote these investments. Austin Energy remains committed to providing cost-based alternative rate structures for customers who wish to reduce their peak demand as this results in mutual benefits for the customer and the utility. The only change proposed at this time for the thermal energy storage rate alternative is to allow customers to choose whether their on-peak period is from 4 p.m. to 8 p.m. or 3:00 p.m. to 7:00 p.m. This improves the flexibility that customers have for maximizing their investment in this technology.

Thermal Storage On-Peak Periods

The Thermal Energy Storage rate offered to customers is a TOU alternative rate. The rate is applicable to commercial and industrial customers served under AE's standard applicable rates.

Currently the summer On-Peak period is: 4:00 p.m. to 8:00 p.m., Monday through Friday; May 1 through October 31.

The proposed new summer On-Peak period is: 4:00 p.m. to 8:00 p.m., Monday through Friday; June 1 through September 30. Alternatively, at the customer's option, 3:00 p.m. to 7:00 p.m., Monday through Friday; June 1 through September 30.

Standby Rates

Standby rates apply to industrial customers who self-generate all or nearly all of their own power. Effectively, AE provides backup service to the power supply for these customers in the event of a planned or unplanned power outage on the customer premise. Austin Energy currently offers a Primary Standby Capacity and Transmission Standby Capacity rate to industrial customers. Services provided by AE to these customers include support of the electric delivery system as the customer is still connected to the power grid and therefore has access to power at any time, and the provision of firm power supply as AE is able to deliver power at a moment's notice to backup a customers' self-owned and operated power supply.

All AE customers currently receiving standby service are under the terms of a special contract. Therefore, the utility is proposing to remove the current standby rates from the tariff and put any new customers with standby service into similar contracts as needed.

Long-Term Plan for Commercial and Industrial Pricing

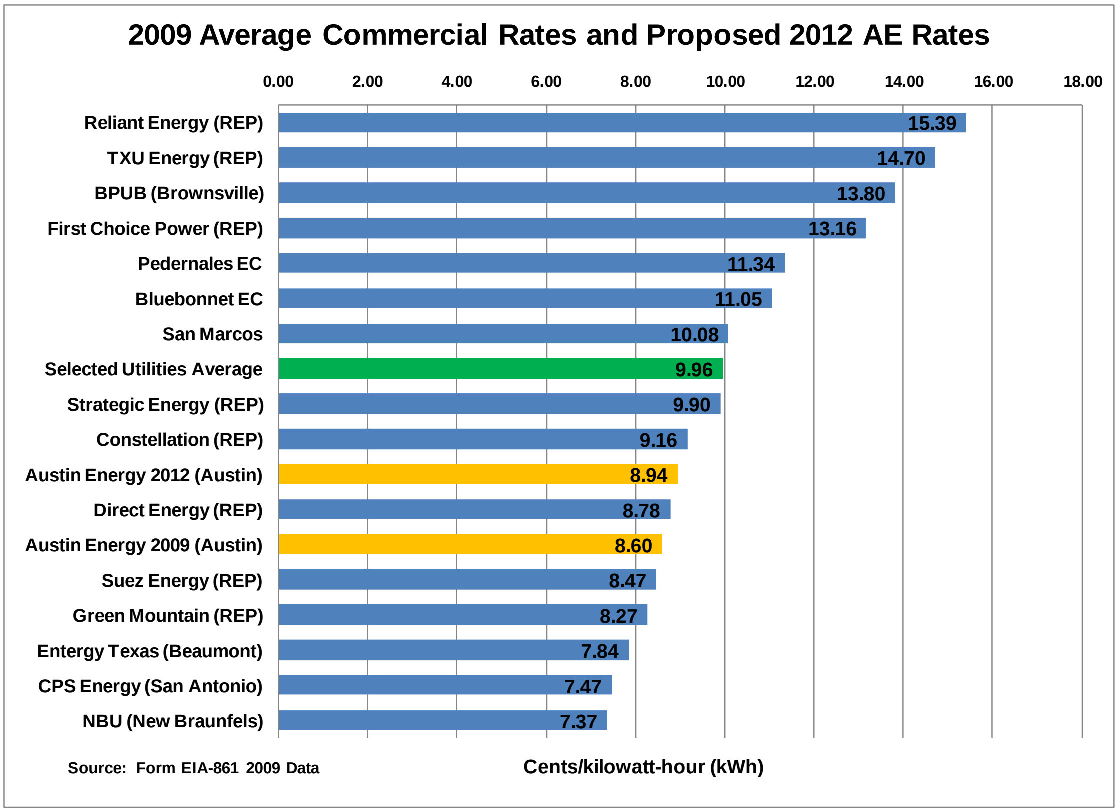
The proposed commercial and industrial alternative rates were designed to address the current needs of customers. Austin Energy views these proposed rate structure changes, including the unbundling of rates, as an initial step towards a technology-enabled future where customers are given strong pricing signals to adjust their electricity usage in real-time. The realization of this goal requires infrastructure investment as well as consumer adoption of certain technologies and products. Austin Energy has invested in an advanced metering infrastructure, or smart grid system, that now serves all of its customers allowing for greater system control. This also enables new electricity pricing models to be developed and new opportunities for customer management of energy use if customers adopt certain technologies on their side of the meter.

Austin Energy can leverage its investments in the smart grid as well as a new customer billing system by offering rate structures that provide customers with improved price signals and more electricity usage data. The TOU alternative rates for the commercial and industrial customer classes are a step in this direction. Pricing signals can be further developed by providing an hourly or even a real-time price based on the market-clearing price of energy, or MCPE, in ERCOT. Although hourly and real-time pricing structures have been implemented within the electric industry, they are not widely adopted due to technology limitations and lack of consumer interest. This type of long-term commercial and industrial pricing structure will require that AE better understand customer values and behaviors so that it can design rates that ensure the utility remains financially strong. One major risk that AE must consider in moving towards innovative rate design is that rate structures such as real-time pricing tend to reduce overall system load growth and increase volatility of the revenue stream, affecting the financial strength of the utility. For these reasons, AE has a long-term commercial and industrial pricing strategy that considers the principle of gradualism with change taking place incrementally over time so that risks to AE and its customers are minimized. Affordability for all customers can best be achieved by phasing in new rate structure changes and providing a diversity of rate alternatives that improve customer ability to manage their electricity usage.

Commercial and Industrial Rate Benchmarking

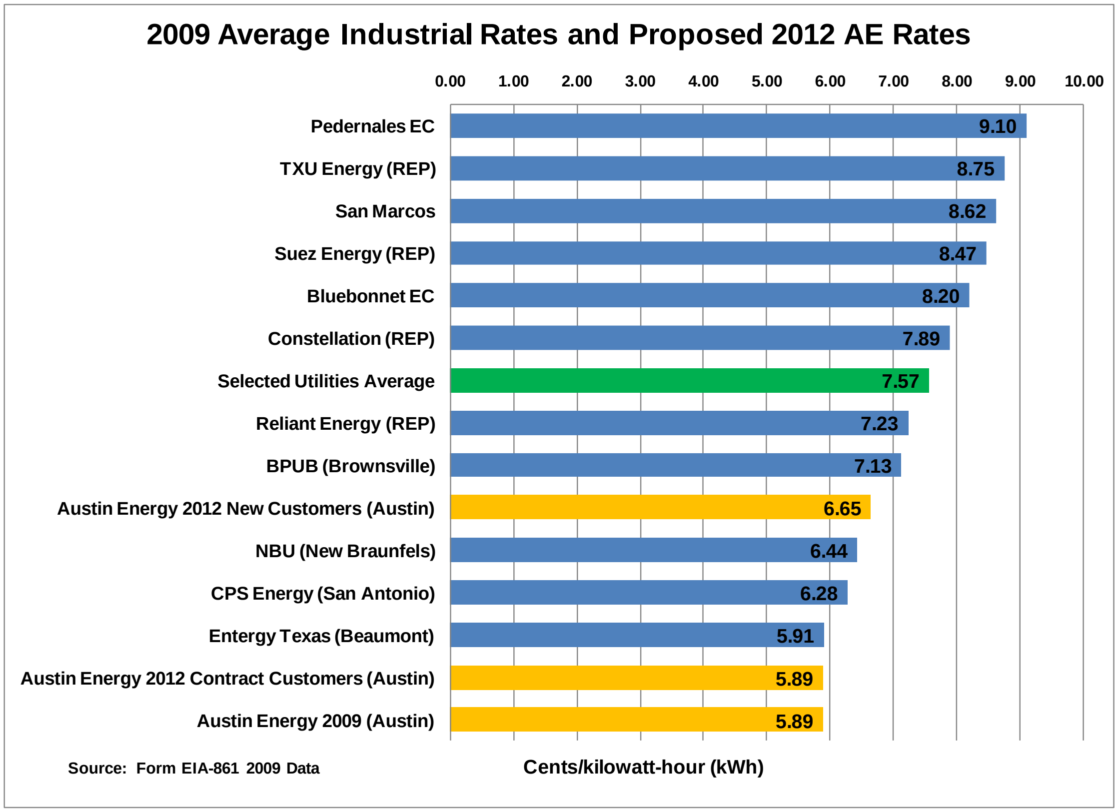
Austin Energy completed its first comprehensive electric rate benchmarking study in November 2010 and concluded that AE's electric rates, particularly average electric bills, have been comparable to, and at times lower than, other utilities and electric service providers in Texas. Figure 7.8 and Figure 7.9, respectively, show average commercial and industrial rate comparisons between AE and other major electric service providers in Texas for 2009 based upon data from the U.S. Energy Information Administration (EIA-861 data). For Figure 7.9 two data points are shown for the proposed rates because existing industrial customers are currently on contract rates through May 2015 so they will not receive a rate increase at this time. Austin Energy 2012 average rates for existing contract customers as well as for new customers at the proposed rates is included in Figure 7.9. This data shows that in 2009 (the last year for which results are currently available and the same year as AE's cost of service study) AE's average commercial and industrial rates were among the lowest in Texas and even under the proposed new rates AE's average remains lower than the average of the selected comparable utilities.

Figure 7.8
Average Commercial Rates in Texas – 2009 Compared to Proposed Average Commercial Rates (Based on Test Year 2009)



Source: EIA Form 861 – 2009, www.eia.doe.gov/cneaf/electricity/page/eia861.html, except for Austin Energy 2012.

Figure 7.9
Average Industrial Rates in Texas – 2009 Compared to Proposed Average Industrial Rates (Based on Test Year 2009)



Source: EIA Form 861 – 2009, www.eia.doe.gov/cneaf/electricity/page/eia861.html, except for Austin Energy 2012.

Section 8
LIGHTING RATE DESIGN

Austin Energy currently provides lighting service under six different rate classes. These rate classes take into consideration differences in ownership of infrastructure and metering capabilities. Current AE lighting rates include:

- Sign Lighting and Safety Illumination Service – This is an energy-only rate applicable to the Texas Department of Transportation for state-owned highway lighting.
- Street Lighting and Traffic Signals (E05) – This is an energy-only rate applicable to city-owned street and traffic lighting facilities
- Security Lighting – This rate is applicable to private outdoor lighting installed, owned, operated, and maintained by the City of Austin. The rate is charged monthly and varies depending upon the type and wattage of bulb installed.
- Non-Metered Outdoor Lighting – This is a formulaic rate that determines the energy usage of various bulbs and charges and applies an energy-only rate.
- Metered Lighting Non-Demand (E02/E13) – The General Service Non-Demand rate (E02) is applicable to customer-owned metered sports lighting. The State General Service Non-Demand (E13) rate is applicable to state-owned meter lighting which consists of the University of Texas sports complexes.

Table 8.1 summarizes the existing rates for rate classes within the lighting customer class which is followed by the proposed new lighting rates for each class.

Table 8.1
Lighting Customer Class – Summary of Existing Rates

Item	Winter Rate Period (November - April)	Summer Rate Period (May - October)
Sign Lighting And Safety Illumination (TXDOT)		
Energy Charge		
All kWh (¢/kWh)	2.96	2.96
Pass-Throughs		
Fuel Adjustment Clause (adjusted for TY)(¢/kWh)	3.398	3.398
Streetlighting and Traffic Signals (E05)		
Energy Charge		
All kWh (¢/kWh)	14.98	14.98
Pass-Throughs		
Fuel Adjustment Clause (adjusted for TY)(¢/kWh)	3.398	3.398
Security Lighting (ENW)		
Pole Charge ($/month)	1.74	1.74
Energy Charge: ($/month)		
175 Watt Mercury Vapor	7.34	7.34
100 Watt High Pressure Sodium	4.28	4.28
400 Watt Mercury Vapor	17.11	17.11
250 Watt High Pressure Sodium	11.00	11.00
Pass-Throughs		
Fuel Adjustment Clause (adjusted for TY)(¢/kWh)	3.398	3.398
Non-Metered Outdoor Lighting (ENW)		
All Non Metered Outdoor Lighting	$0.0428/watt X bulb wattage X 0.35 X bulb wattage X FAC	$0.0428/watt X bulb wattage X 0.35 X bulb wattage X FAC

Proposed Street and Traffic Lighting Rate Structure and Prices

The Street and Traffic Lighting rate is an energy-only rate that reflects the cost of operating, maintaining, and supplying power to all street and traffic lights within AE's service territory. These costs will be recovered by applying a proposed rate of $0.30361 per kWh for all kWh consumed by street and traffic lights within the AE service territory. However, there are no street and traffic lighting customers who will be directly billed at this rate as these costs are proposed to be billed to all other customers through a Service Area Lighting sub-charge under the Community Benefit Charge. Table 8.2 compares the existing street and traffic lighting rate with the proposed rate for the Street and Traffic Lighting rate class.

Table 8.2
Street and Traffic Lighting Existing Rate vs. Proposed Rate

Name of Charge/Rate	Existing Rate With Adjusted TY Fuel	Proposed Rate FY 2012
Energy Charge (¢/kWh) (1)	18.378	30.361
Energy Adjustment (¢/kWh) (2)	n/a	0.00
Community Benefit Charge (3)		
Customer Assistance Program (¢/kWh)	n/a	n/a
Energy Efficiency Charge (¢/kWh)	n/a	0.803
Regulatory Charge (¢/kWh) (4)	n/a	0.093
Transmission Service Adjustment Rider (¢/kWh) (5)	0.000	n/a

Notes:
1. AE's existing Energy Charge does not include fuel-related costs. Fuel is charged separately through the Fuel Adjustment Clause. The Energy Charge shown here includes fuel-related costs based on the normalized TY revenue requirement results (TY 2009 fuel adjustment charge is 3.398 cents per kWh) as these costs are not part of the requested base rate increase.
2. The Energy Adjustment is a new charge that replaces the current Fuel Adjustment Clause. The Energy Adjustment is set to zero but is subject to change as described in Section 5 of this report.
3. The Community Benefit Charge is a new charge that funds three specific programs and services provided to the community by AE. The Customer Assistance Program creates monies to provide discounts to qualified low-income and other disadvantaged customers. Service Area Lighting recovers the cost of street lighting to customers within the entire AE service territory. Energy efficiency recovers the cost of energy efficiency, green building, and solar rebate programs offered by AE.
4. The Regulatory Charge is a new charge that replaces the Transmission Service Adjustment Rider and includes ERCOT administration fees and charges associated with AE's cost of ERCOT transmission.
5. The Transmission Service Adjustment is a current charge associated with AE's increased cost of ERCOT transmission to support State transmission build-out. This adjustment would be discontinued under the proposed rate structure and these costs would be included in the new Regulatory Charge.

The increase in service area street lighting expense can be attributed to the use of the AED methodology, as described in Section 4, applicable to the production function and direct assignments of distribution function costs associated with street lighting infrastructure. The AED method assigns a portion of production function demand-related cost to each customer class based on the class' excess demand. Excess demand is calculated using the class NCP. For the lighting classes, the NCP occurs in the evening, but the AED method assumes that production demand provides value to all customer classes regardless of the class contribution to the system peak.

Metered Lighting Rate Structure and Prices

Metered lighting is lighting service applicable to ball fields, stadiums, and other public venues requiring significant illumination. This rate reflects the cost of supplying power to the outdoor lighting at these facilities. Table 8.3 compares the existing metered lighting rate with the proposed rate for the Customer-Owned Metered Lighting customer class.

Table 8.3
Metered Lighting (E02) Existing Rate vs. Proposed Rate

Name of Charge/Rate	Existing Rate With Adjusted TY Fuel	Proposed Rate
Customer Charge ($/month)	6.00	15.00
Energy Charge[1] **(¢/kWh)**		
Summer [2]	9.838	18.201
Non-summer [2]	8.038	16.701
Energy Adjustment Clause (¢/kWh) [3]	n/a	0.00
Community Benefit Charge (¢/kWh) [4]		
Customer Assistance Program (¢/kWh)	n/a	0.065
Service Area Street Lighting (¢/kWh)	n/a	0.180
Energy Efficiency Charge (¢/kWh)	n/a	0.473
Regulatory Charge (¢/kWh) [5]	n/a	0.318
Transmission Service Adjustment Rider (¢/kWh) [5]	0.028	n/a
Percent Class Rate Change (%)		116.2

Notes:
1. AE's existing Energy Charge does not include fuel-related costs. Fuel is charged separately through the Fuel Adjustment Clause. The Energy Charge shown here includes fuel-related costs based on the normalized TY revenue requirement results (TY 2009 fuel adjustment charge is 3.398 cents per kWh) as these costs are not part of the requested base rate increase.
2. The Energy Adjustment is a new charge that replaces the current Fuel Adjustment Clause. The Energy Adjustment is set to zero but is subject to change as described in Section 5 of this report.
3. The Community Benefit Charge is a new charge that funds three specific programs and services provided to the community by AE. The Customer Assistance Program creates monies to provide discounts to qualified low-income and other disadvantaged customers. Service Area Lighting recovers the cost of street lighting to customers within the entire AE service territory. Energy efficiency recovers the cost of energy efficiency, green building, and solar rebate programs offered by AE.
4. The Regulatory Charge is a new charge that replaces the Transmission Service Adjustment Rider and includes ERCOT administration fees and charges associated with AE's cost of ERCOT transmission.
5. The Transmission Service Adjustment is a current charge associated with AE's increased cost of ERCOT transmission to support State transmission build-out. This adjustment would be discontinued under the proposed rate structure and these costs would be included in the new Regulatory Charge.

Electric Bill Impact Analysis

Customers served under this rate use an average of 7,238 kWh per month during the summer season and 7,771 kWh per month during the non-summer season. Under the proposed rates, at average usage, a customer would have an average annual bill of $1.410.72 under the proposed rates compared to $654.43 under existing rates. This increase represents an increase in the monthly bill of $756.29 or 116 percent. The increase in metered lighting rates can be attributed to the use of the AED methodology, as described in Section 4, applicable to the production function.

Proposed Austin Energy-Owned Private Outdoor Lighting Rate Structure and Prices

Austin Energy-owned private outdoor lighting is applicable to customers that have security lighting facilities owned and operated by AE on their premises. This rate consists of a monthly pole fee and an energy charge based on the energy usage of a variety of standard bulb installations. Table 8.4 compares the existing AE-owned non-metered outdoor lighting rate with the proposed rate.

Table 8.4
Austin Energy-Owned Private Outdoor Lighting Existing Rate vs. Proposed Rate

Name of Charge/Rate	Existing Rate With Adjusted TY Fuel	Proposed Rate
Pole Charge (1)	$1.74	n/a
Energy Charge All Year:		
100 Watt High Pressure Sodium	$ 6.02	$ 11.00
175 Watt Mercury Vapor	$9.08	$19.00
250 Watt High Pressure Sodium	$12.74	$ 28.50
400 Watt Mercury Vapor	$18.85	$ 44.50
Energy Adjustment (¢/kWh) (2)	n/a	n/a
Community Benefit Charge (¢/kWh) (3)		
Customer Assistance Program ($/kWh)	n/a	n/a
Service Area Street Lighting ($/kWh)	n/a	n/a
Energy Efficiency Charge ($/kWh)	n/a	n/a
Regulatory Charge ($/kWh) (4)	n/a	n/a
Percent Class Rate Change (%)		87.5

Notes:
1. The proposed energy charge includes a pole fee.
2. The Energy Adjustment is a new charge that replaces the current Fuel Adjustment Clause. The Energy Adjustment is set to zero but is subject to change as described in Section 5 of this report.
3. The Community Benefit Charge is a new charge that funds three specific programs and services provided to the community by AE. The Customer Assistance Program creates monies to provide discounts to qualified low-income and other disadvantaged customers. Service Area Lighting recovers the cost of street lighting to customers within the entire AE service territory. Energy efficiency recovers the cost of energy efficiency, green building, and solar rebate programs offered by AE.
4. The Regulatory Charge is a new charge that replaces the Transmission Service Adjustment Rider and includes ERCOT administration fees and charges associated with AE's cost of ERCOT transmission.

Electric Bill Impact Analysis

Table 8.5 compares the proposed security lighting charges with existing charges and shows the differences in prices for each type of lighting fixture applicable under this rate.

Table 8.5
Security Lighting Current Charges vs.Proposed Charges

Fixture	Existing Rate-Pole Charge ($/mo)	Existing Rate Energy Charge ($/mo)	Existing Rate Total ($/mo)	Proposed Rate-Fixture Charge ($/mo)	Diff $	Diff %
100 Watt High Pressure Sodium	1.74	6.02	7.76	11.00	3.24	41.8
175 Watt Mercury Vapor	1.74	9.08	10.82	19.00	8.18	75.6
250 Watt High Pressure Sodium	1.74	12.74	14.48	28.50	14.02	96.8
400 Watt Mercury Vapor	1.74	18.85	20.59	44.50	23.91	116.1

The increase in AE-owned private outdoor lighting rates can be attributed to the use of the AED methodology, as described in Section 4, applicable to the production function and direct assignments of distribution function costs associated with private area lighting infrastructure.

Non-Metered Lighting (TxDOT) Rate Structure and Prices

The non-metered lighting rate is an energy-only rate applicable to the Texas Department of Transportation (“TxDOT”) for state-owned highway lighting. Table 8.6 compares the existing rate with the proposed rate for the Customer-Owned Metered Lighting (TxDOT) customer class.

Table 8.6
Customer-Owned Non-Metered Lighting Rate vs. Proposed Rate

Name of Charge/Rate	Existing Rate With Adjusted TY Fuel	Proposed Rate
Energy Charge		
All kWh – All Year (¢/kWh)	6.358	9.376
Energy Adjustment Clause (¢/kWh) (1)	n/a	0.00
Community Benefit Charge (¢/kWh) (2)		
Customer Assistance Program ($/kWh)	n/a	0.065
Service Area Street Lighting ($/kWh)	n/a	0.095
Energy Efficiency Charge ($/kWh)	n/a	0.25
Regulatory Charge ($/kWh) (3)	n/a	0.095
Percent Class Change (%)		28.5

Notes:
1. The Energy Adjustment is a new charge that replaces the current Fuel Adjustment Clause. The Energy Adjustment is set to zero but is subject to change as described in Section 5 of this report.
2. The Community Benefit Charge is a new charge that funds three specific programs and services provided to the community by AE. The Customer Assistance Program creates monies to provide discounts to qualified low-income and other disadvantaged customers. Service Area Lighting recovers the cost of street lighting to customers within the entire AE service territory. Energy efficiency recovers the cost of energy efficiency, green building, and solar rebate programs offered by AE.
3. The Regulatory Charge is a new charge that replaces the Transmission Service Adjustment Rider and includes ERCOT administration fees and charges associated with AE's cost of ERCOT transmission.

Non-Metered Lighting Customer Electric Bill Impact Analysis

Currently, the only customer served under this rate is the Texas Department of Transportation. The proposed rate represents a 28.5 percent increase in their bill under this rate. The increase in lighting rates can be attributed to the use of the AED methodology, as described in Section 4, applicable to the production function.

Section 9

RATE REVIEW FINDINGS AND RECOMMENDATIONS

This section of the report summarizes the findings of AE during this rate review and lists the utility's recommendations for proposed new rates. The findings and recommendations of this rate review are based upon consideration of the rate review objectives and rate design principles, the cost of service and rate design analysis detailed in the Rate Analysis and Recommendations Report, and input from the public, AE staff, and rate consultants.

Measures of the rate review policy goals presented in Section 1 of this report follow the presentation of the utility's recommendations to demonstrate that the proposed rates meet the policy guidelines recommended by AE for this rate review. This is followed by a decision point list which will serve as a decision making guide during the EUC and City Council review process.

Revenue Requirement

The first step in the rate review process was the determination of the total utility revenue requirement for Test Year 2009 to represent the utility's normalized expenses and investment required to provide reliable electric services to customers and fulfill the utility's strategic objectives. To ensure that rates adequately recover costs, the revenue requirement represents historical expenditures, capital improvement requirements, and customer loads adjusted for current known and quantifiable changes. An historical fiscal year (FY 2009) was chosen and then adjusted based on "known and measurable" criteria to reflect typical or expected future financial and operating conditions of the utility. This adjustment resulted in a "Test Year" that represents the total costs to operate AE during a typical year.

Fiscal Year 2009 rate revenue was calculated based on AE's existing rates utilizing the same normalized customer sales used in the Test Year Revenue Requirement. Table 2 shows that about $1 billion would be expected to be generated from AE's existing rates, resulting in a short fall of $131,886,906 (or 13.1 percent). Although this study shows that the utility would experience a 13.1 percent shortfall of revenues in the Test Year, the utility is only requesting an increase in base electric rates of $111,135,775 or an 11.1 percent increase in revenues. This is because 17 of AE's largest commercial and industrial customers (contract customers) are currently under contract terms which do not allow the utility to adjust their rates until June 2015. Based on this study, these customers are collectively under cost of service by about $20 million a year. Table 9.1 summarizes the utility's total revenue, revenue need, and requested increase in revenues for 2012.

Table 9.1
Total Revenue and Revenue Need

Measure	Test Year 2009
Total Revenue Requirement ($)	1,136,020,803
Test Year Rate Revenue Under Existing Rates ($)	1,004,133,897
Needed Increase in Revenues ($)	131,886,906
Needed Increase in Revenues (%)	13.1
Needed Increase in Revenues From Contract Customers ($)	20,751,131
Requested Increase in Revenues ($)	111,135,775
Requested Percent Increase in Revenues (%)	11.1

The results of the TY Revenue Requirement show that AE is currently significantly under-recovering revenues needed to meet the costs required to serve its customers. This is expected as AE has not increased its base rates since 1994. Continued failure to meet the utility's revenue requirement would threaten the financial strength of the utility and its ability to fulfill its strategic objectives. Table 9.2 summarizes AE's recommendations associated with the utility's revenue requirement.

Table 9.2
Summary of Recommendations Associated with AE's Revenue Requirement

Recommendation	Reason(s)
Revenue Requirement Methodology	
1) Revenue requirement should be developed using the cash approach methodology	▪ The cash approach is widely adopted and used for municipal utilities and recognizes that a municipal utility operates on a cash basis and is a not for profit entity. The cash approach is consistent with AE's financial policies and bond covenants. Additionally, the cash approach is recognized by the PUCT in TCOS rules.
Achieve Total Utility Revenue Requirement	
2) Revenue requirement as established for Test Year 2009 is sufficient to meet AE's operating costs and capital requirements consistent with its business objectives. Therefore, revenue requirement as proposed should be adopted.	▪ The Test Year 2009 revenue requirement reflects a comprehensive review of AE's costs and cost structure. Adopting the revenue requirement will ensure AE's continued financial strength.

Consolidation of Customer Classes

A customer class is a grouping of customers with similar characteristics. In the electric utility industry, customer classes exist because the cost to serve different customers can vary substantially depending on a customer's service needs and the way in which the customer consumes electricity. For example, customers with large loads (i.e., large commercial and industrial) tend to use energy in larger amounts than residential and small commercial customers and more consistently during the day which impacts the cost to serve these customers. Correspondingly, the cost to deliver electricity to a very large commercial or industrial customer is different from the cost to deliver electricity to a residential home. The industrial customer may receive electricity from a single high-voltage line that extends directly from a substation while a home receives its electricity from a series of lines that start from a substation and eventually reach the home.

Typically, customers are grouped together into classes based upon common service requirements and electricity usage characteristics. Because the cost to serve customers with shared characteristics tends to be similar, customer classes were formed to bill groups of customers in a common manner. A utility must evaluate its customer classes and make any necessary adjustments to its customer classes before completing the cost of service study. This ensures that the cost of service analysis produces accurate and meaningful results.

Since AE's 1994 rate review, the number of customer classes and price offerings within customer classes has expanded and become increasingly complex. Currently, AE supports 24 distinct customer classes and nearly 90 unique price offerings. After reviewing the service requirements and electricity usage characteristics for customers within each of the existing 24 customer classes, AE and its rate consultants determined that many of these customer class distinctions were unnecessary and not consistent with industry best practices for designing customer classes.

Austin Energy evaluated an extensive amount of customer data, including billing data and load research, to redesign customer classes based upon industry best practices. Austin Energy is recommending that customer classes be consolidated from 24 to 9 customer classes to better recognize the underlying cost of service for each class, to create meaningful cost of service differentials between customer classes, and to better align with the best practices of other Texas electric utilities. This consolidation will simplify and improve the understandability of AE's rates. Table 9.3 summarizes the proposed recommendations associated with AE's customer classes.

Table 9.3
Summary of Recommendations Associated with AE's Customer Classes

Recommendation	Reason(s)
1) Consolidate from 24 to 9 customer classes.	▪ Bases customer classes on cost of service differentials, including unique service requirements and electricity usage characteristics; ▪ Simplifies and improves the understandability of AE's customer classes; and ▪ Aligns better with other Texas electric utilities.
2) Remove worship facilities from Residential customer class and group into appropriate Secondary Voltage customer class.	▪ Customer service requirements and electricity usage characteristics substantially differ from residential customers and from each other; and ▪ Customer characteristics suggest worship facilities should be grouped into the appropriate Secondary Voltage class based on demand.
3) Remove City, School, and State customer classes and rate classes and group into appropriate Secondary Voltage or Primary Voltage customer class.	▪ Customer service requirements and electricity usage characteristics are similar to other commercial customers; ▪ Customer characteristics suggest these customer classes should be grouped into the appropriate Secondary Voltage or Primary Voltage class based on demand; and ▪ Simplification of rates.
4) Lower the break point for non-demand versus demand commercial customers from 20 kW to 10 kW.	▪ Customer service requirements and electricity usage characteristics for customers with demand less than 10 kW are similar; ▪ Consistency with other Texas utilities; and ▪ Allows unique rate treatment for this group of customers consistent with cost of service results.
5) Establish a break point for Secondary Voltage customers for those with demand greater than or equal to 10 kW and less than 50 kW and those above 50 kW.	▪ Customer service requirements and electricity usage characteristics differ among commercial customers receiving service at the secondary voltage level; and ▪ Allows unique rate treatment for these groups of customers consistent with cost of service results.
6) Establish a break point for Primary Voltage customers for those with demand less than 3 MW, those greater than or equal to 3 MW and less than 20 MW, and those greater than or equal to 20 MW.	▪ Customer service requirements and electricity usage characteristics differ among commercial and industrial customers receiving service at the primary voltage level; and ▪ Allows unique rate treatment for these groups of customers consistent with cost of service results.

This consolidation of customer classes requires that certain customers be assigned to new customer classes based on their service characteristics and level of demand on the system (in kilowatts, or kW). In some instances, moving a customer into a new customer class may actually lower their electric bill while in other cases a customer's electric bill may increase. For this reason, bill impacts under the proposed new rates for all existing customer classes were included in this report.

Cost of Service

After determining the utility's revenue requirement and making adjustments to the customer classes, a cost of service analysis was performed to determine how much it costs the utility to provide electric services to each proposed customer class. The cost of service analysis helps the utility determine what charges and prices, or rates, to apply to each customer class or rate class.

The cost of service analysis distributes the utility's revenue requirement by applying methodologies for allocating costs commonly used throughout the industry. Various calculation methodologies can be used in a cost of service study to determine the allocation of costs to different customer classes. Table 7 summarizes AE's recommendations associated with the cost of service study completed for this rate review.

Table 9.4
Summary of Recommendations Associated with AE's Cost of Service Study

Recommendation	Reason(s)
Cost Allocation Methodology	
1) Cost of service should be conducted using an unbundled embedded cost methodology.	▪ Unbundled embedded cost methodology is widely used in the electric utility industry in general and is specifically used in Texas. This methodology is employed by the PUCT. Unbundling provides maximum understanding of the underlying cost causation and increased flexibility with respect to rate design.
Production Cost Allocation	
2) Allocation of production demand-related costs should be based on the AED method.	▪ The AED method is widely used across the electric utility industry. Variations of this method are recognized and approved by the PUCT. The method allocates production demand-related costs to classes consistent with class load factor. Additionally, the method recognizes that generation capacity has value regardless of a customer class' contribution to the system peak. Overall, the AED method represents a reasonable assessment of the value AE's generation resources provide to various customer classes. Additionally the method is consistent with AE's energy efficiency and conservation goals that seek a reduction in the customer's contribution to system demand.
3) Allocation of production energy-related costs should be based on the NEFL method.	▪ The NEFL method is widely used across the industry in the allocation of energy to customer classes. This method recognizes system line loss differentials for customers served at various voltages.

Transmission Cost Allocation	
4) Allocation of transmission demand-related costs should be based on the ERCOT 4CP method.	▪ The ERCOT 4CP method is used by ERCOT in the allocation of transmission costs to AE. This approach directly aligns customer class electricity usage characteristics with cost causation. ERCOT 4CP is also the basis of the current AE Transmission Service Adjustment Rider.
Distribution Cost Allocation	
5) Allocation of distribution demand-related costs should be as follows: Substations, poles, conductors, and load dispatch should be allocated based on the 12 Non-CP ("12 NCP") method. ▪ Transformers and services should be allocated based on the Sum of Maximum Demands method.	▪ The 12 NCP method allocates costs to customer classes based on the class maximum demand for each month of the year. This approach recognizes that the distribution system is designed to meet class loads rather than system loads. 12 NCP is used to reflect varying class demands during the year. Load dispatch is allocated in a similar manner, reflecting the cost of operating the system to meet customer class demands. ▪ Transformers and services are allocated based on the sum of maximum demands or billing demands. This methodology reflects that transformers and services are sized to meet individual customer loads.
6) Allocation of customer-related costs for meters should be allocated based on weighted number of customers.	▪ Meters are allocated to customer classes in consideration of the underlying investment. Customer weighting factors were developed for residential, commercial, and industrial meters.
7) Distribution direct assignment costs are related to street lighting.	▪ The cost of street lighting throughout the AE service territory was directly identified in the cost of service study and assigned to a system street lighting customer class.
Customer Cost Allocation	
8) Allocation of customer service function costs should be as follows: Customer service, customer accounting, and meter reading should be allocated based on the number of customers. Uncollectible accounts and key accounts should be allocated based on a weighted number of customers.	▪ The level of effort and associated costs of customer service, customer accounting, and meter-related activities are directly related to number of customers. ▪ The level of effort and associated costs of uncollectible accounts and key accounts greatly vary between customer classes. Each is unique and, therefore, a separate weighted allocation was developed.

The fully allocated cost of service study shows how much a customer class is over-paying or under-paying for electric service. Detailed cost of service results by customer class using the allocation methodologies summarized in Table 9.4 are presented in Table 9.5. Table 9.5 summarizes the total cost of service results by customer class compared to estimated Test Year revenues under AE's existing rates (more detailed results are presented in the Rate Analysis and Recommendations Report). Table 10 also indicates the shortfall in revenue needed from each customer class, or the percentage rate increase needed to meet class cost of service. Overall, the indicated shortfall, consistent with the shortfall of the Test Year revenue requirement, is 13.1 percent of revenue needs, or $1,136,020,803. Over 80 percent of the revenue shortfall is attributed to the Residential customer class, which the utility is under-recovering in the Test Year by approximately $107 million, or 29 percent below cost of service. Almost 8 percent of the shortfall is attributed to the Secondary Voltage <10 kW customer class which the utility is under-recovering from by approximately $10 million. With the exception of Primary Voltage <3 MW and Transmission Voltage, all other customer classes are also currently below their cost of service.

Table 9.5
Rate Increase Needed to Meet Cost of Service by Customer Class

Customer Class	Cost of Service [(1)] ($)	Projected Revenue Under Existing Rates [(2)] ($)	Revenue Deficiency ($)	Increase Needed to Meet Cost of Service (%)
Residential	480,335,595	373,304,903	107,030,692	28.7
Secondary Voltage <10 kW	46,438,756	36,421,201	10,017,555	27.5
Secondary Voltage 10 - <50 kW	94,426,817	91,141,558	3,285,259	3.6
Secondary Voltage ≥50 kW	352,218,949	349,970,012	2,248,936	0.6
Primary Voltage <3 MW	29,189,906	30,377,964	(1,188,058)	-3.9
Primary Voltage 3 - <20 MW	51,704,287	47,083,898	4,620,389	9.8
Primary Voltage ≥20 MW	62,622,337	57,555,036	5,067,301	8.8
Transmission Voltage	14,194,875	15,816,915	(1,622,040)	-10.3
Service Area Street Lighting	N/A	N/A	N/A	N/A
AE-Owned Private Outdoor Lighting	3,860,477	1,955,348	1,905,130	97.4
Non-Metered Lighting	176,279	131,138	45,141	34.4
Metered Lighting	852,526	375,924	476,601	126.8
Total	**1,136,020,803**	**1,004,133,897**	**131,886,905**	**13.1**

Notes:
1. Reflects the AED method for allocating production costs and excludes CAP funding.
2. Adjusted for Test Year 2009 fuel.

Table 9.6 shows proposed revenues by customer class compared to cost of service for each class. The table demonstrates the changes in customer class revenue due to the recommended policy adjustment setting bounds on alignment with cost of service.

Table 9.6
Cost of Service Compared to Class Revenue Target by Customer Class

Customer Class	Cost of Service (COS) (1) ($)	Proposed Class Revenue Target ($)	Difference ($)	Revenue Target as a Percent of COS (%)
Residential	480,335,595	456,325,851	24,009,744	95
Secondary Voltage <10 kW	46,438,756	44,114,521	2,324,235	95
Secondary Voltage 10 - <50 kW	94,426,817	98,576,974	-4,150,157	104
Secondary Voltage ≥50 kW	352,218,949	367,737,239	-15,518,290	104
Primary Voltage <3 MW	29,189,906	30,473,403	-1,283,497	104
Primary Voltage 3 - <20 MW	51,704,287	53,977,832	-2,273,545	104
Primary Voltage ≥20 MW	62,622,337	65,380,102	-2,757,765	104
Transmission Voltage	14,194,875	14,818,365	-623,490	104
AE-Owned Private Outdoor Lighting	3,860,477	3,659,173	201,304	95
Non-Metered Lighting	176,279	167,461	8,818	95
Metered Lighting	852,526	809,927	42,599	95
Total	**1,136,020,803**	**1,136,040,848**	**-20,045**	**100**

Note:
1. Reflects the AED method for allocating production costs and excludes CAP funding.

General Rate Design

After determining the utility's revenue requirement and completing the cost of service analysis, AE developed its rate proposal. This final step in the ratemaking process is called rate design. Rates can generally be defined as a system of charges developed to collect desired revenues. The overall objective is to design rates that fully recover the utility's revenue requirement, fairly allocate costs to customers, and align with the utility's strategic objectives. Proposed new rates summarized in this report and detailed in the Rate Analysis and Recommendations Report are based on AE's adopted rate review objectives and are designed to ensure that customers pay fair and equitable rates that remain affordable. Table 9.7 summarizes AE's recommendations associated with rate design that apply to all customers. This is followed by a short description of each charge proposed under the new rate design.

Table 9.7
Summary of Recommendations Associated with Rate Design Common to All Customers

Recommendation	Reason(s)
1) Unbundle rates and apply a customer charge, electric delivery charge, energy charge, regulatory charge, community benefit charge, and energy adjustment for all customers and an additional demand charge and power cost adjustment for commercial and industrial customers.	▪ Improves fixed cost recovery and overall recovery of revenues to meet the utility's revenue requirement; ▪ Improves pricing transparency; and ▪ Improves future flexibility with respect to rate design.
2) Expand use of pass-through charges by adding a regulatory charge (transmission and ERCOT fees) and community benefit charge (for Customer Assistance Program, service area street lighting, and energy efficiency) and removing these costs from other existing charges.	▪ Helps effectively manage the risk of variable costs, such as fuel costs, that are predominantly outside AE's control; and ▪ Improves pricing transparency.
3) Recover Test Year fuel-related costs in the energy charge, establish a rate stabilization fund, and apply an energy adjustment in future years to account for future fluctuations in these costs when needed.	▪ Maintains transparency of fuel-related and energy market costs; and ▪ Minimizes volatility of adjustment factor through use of a rate stabilization fund.
4) Shorten summer season from six months (May – October) to four months (June – September) so that stronger pricing signals can be provided during the summer rate period.	▪ Stronger pricing signals incentivize customers to reduce summer peak demand by improving the efficiency of end-use equipment or investing in alternative technologies such as solar PV and thermal storage; and ▪ Aligns with ERCOT summer and non-summer time periods.
5) Establish a goal that no customer class pays greater than 105 percent or less than 95 percent of its cost of service in the implemented new rates, with the condition that the utility achieve its total revenue requirement through implemented rates.	▪ Establishes fair and equitable rates; and ▪ Minimizes inter-class subsidization.
6) Establish a goal to move long-term contract customers into cost of service-based rates upon expiration of existing contracts in May 2015.	▪ Establishes fair and equitable rates; and ▪ Ensures the utility's future financial strength.
7) Maintain an alternative renewable energy rate (GreenChoice) for customers who wish to pay a premium for renewable energy and use a bundled portfolio approach.	▪ Helps meet customer demand for renewable energy; and ▪ A bundled portfolio approach for pricing renewable energy allows for AE to price renewable energy based on the entire portfolio of renewable resources maintained by the utility.

8) Maintain an alternative rate for customers with distributed generation (e.g., solar PV) and credit excess monthly generation based on the utility's determination of the annual value of solar PV to the system.	▪ Helps meet customer demand; ▪ Ensures sufficient fixed cost recovery for distributed generation customers; and ▪ The credit at the value of solar rate rewards customers for excess electricity generated over the year.
9) Work with the Pecan Street Project to pilot new rates for customers. Any pilot project implemented must first be approved by the City Council.	▪ Provides the opportunity to explore new rate options to meet customer needs and the utility's strategic objectives while potentially reducing costs to the utility and customers; and ▪ Piloting rates minimizes the risks to the utility and customers.

Residential Rate Design

The cost of service study indicates that current residential electric rates do not adequately recover the cost to serve residential customers, particularly customers with relatively low usage or average usage. Given the results of the cost of service analysis and consideration of AE's rate review objectives, AE's recommendations associated with residential rate design are summarized in Table 9.8.

Austin Energy also prepared several rate design options for residential customers. While these different options are all designed to recover the full revenue requirement associated with residential electric service in the Austin community, they vary in some important ways. All AE residential rate options seek to recover more of the cost of service from fixed charges than was the case in the 1994 rates. Any one of the options seek to implement rates strictly according to the cost of service analysis. The utility's goal is to implement rate redesign as close to cost of service as possible. Strict implementation would be impractical.

All AE residential rate design options continue the long-standing structure of providing a lower rate for the first tier of usage to encourage conservation and support efficient energy use. Some of the options include additional rate levels or tiers, with the rate increasing progressively as customers increase total energy use. This design feature encourages even more efficient use of energy by providing customers with a real savings incentive.

Table 9.8
Summary of Recommendations Specific to Residential Rate Design

Recommendation	Reason(s)
1) Raise the current residential customer charge from $6 to $15 and remove this portion of residential customer-related costs from the variable energy charge.	▪ Increase supported by cost of service study; and ▪ Improves fixed cost recovery
2) Move distribution costs from the energy charge to an electric delivery charge for residential customers set at $10 and remove this portion of residential distribution costs from the variable energy charge.	▪ Unbundles the distribution function (wires) in the rate structure to improve pricing transparency and improve fixed cost recovery; and ▪ Improves transparency of rate design.
3) Expand existing residential inclining block rate structure from two tiers to five tiers.	▪ Provides stronger conservation and energy efficiency pricing signals to the highest users in the Residential customer class.
4) Implement a TOU rate option for residential customers with an initial 2,000 customer enrollment cap.	▪ Offers residential customers an incentive and option to shift demand and energy usage to off-peak periods when producing electricity is less costly to the utility; ▪ Provides AE important information with respect to customer behavior and demand response associated with TOU pricing signals; and ▪ Moves AE towards its long-term residential pricing objectives while reducing risks to the utility's financial stability (by offering this on a limited basis).
5) Institute a fee within the Community Benefit Charge that creates a pool of monies to assist Customer Assistance Program participants.	▪ Provides economic assistance to a greater number of low-income customers in need of assistance; ▪ Allows flexibility to administer funds to best meet the needs of Customer Assistance Program participants; and ▪ Consistent with funding mechanism used in the competitive markets in Texas.
6) Establish a goal that no residential electric bill below 1,500 kWh will increase by more than $20 a month on average.	▪ Maintains affordability of electricity while promoting efficient electricity use.

Commercial and Industrial Rate Design

The cost of service study indicates that while fixed cost recovery is a significant challenge for the Residential customer class, the current misalignment of fixed costs and fixed revenue recovery is not as pronounced for AE's commercial and industrial customer classes. Austin Energy is proposing a more equitable fixed cost recovery structure by removing customer service and distribution costs currently recovered in the demand charge and applying a customer charge and electric delivery charge for all commercial and industrial customers.

Currently, commercial and industrial customers with a peak demand of over 20 kW are assessed a demand charge (in kW), which is a charge specifically designed to collect fixed costs. A demand charge reflects the way in which certain costs are incurred and provides an incentive for customers to reduce their demand by making energy efficiency improvements or controlling the maximum demand they place on the system. Currently, small commercial customers with a peak demand of less than 20 kW do not pay a demand charge. Austin Energy is proposing that these small commercial customers be charged for demand under the new rate design. Charging all commercial and industrial customers a demand charge will improve fixed cost recovery from this customer segment and provide a pricing signal for energy efficiency and conservation to all customers. Austin Energy currently has almost 35,000 non-demand commercial customers. Austin Energy is proposing that current non-demand customers receive transition rates designed to mitigate immediate rate impacts on these customers as they transition from a non-demand rate to a demand rate.

Given these considerations, as well as consideration of AE's rate review objectives, AE's recommendations for commercial and industrial rate design are summarized in Table 9.9.

Table 9.9
Summary of Recommendations Specific to Commercial and Industrial Rate Design

Recommendation	Reason(s)
1) Introduce and apply a customer charge at or near cost of service for all commercial and industrial customers.	▪ Improves fixed cost recovery; and ▪ Improves transparency of rate design.
2) Unbundle rates and apply an electric delivery charge on a $/kW basis at or near cost of service for all commercial and industrial customers.	▪ Unbundles the distribution function (wires) in the rate structure to improve pricing transparency and improve fixed cost recovery; and ▪ Improves transparency of rate design.
3) Expand the use of demand charges to all Secondary Voltage customers	▪ Demand charges send a strong pricing signal to customers. The signal encourages customers to reduce demand and improve efficiency.
4) Phase in demand-related charges (electric delivery and demand charge on a $/kW basis) over three years for current non-demand customers including all Secondary Voltage <10 kW customer class.	▪ Mitigates the immediate rate impacts for commercial and industrial customers who do not currently have a demand charge.
5) Increase power factor adjustment from 85 to 90 percent to all commercial and industrial customers.	▪ Customers with higher power factors have a lower cost of service. A power factor adjustment recognizes this difference; and ▪ Creates incentive for commercial and industrial customers to improve their power factor.
6) Implement a TOU rate option for each commercial and industrial class with an enrollment cap of the higher of 10 percent of the customers in the class or 10 customers for each class.	▪ Promotes energy efficiency investment, conservation, and load shifting; and ▪ Encourages customers to reduce demand during the time of the system peak (the most expensive hours to serve customers) thereby creating cost savings mutually shared by the customer and AE; and ▪ Provides AE important information with respect to customer behavior and demand response associated with TOU pricing signals.
7) Revise existing thermal storage rate to offer customers increased flexibility with respect to on-peak pricing periods.	▪ Supports individual customer desire to invest in thermal storage technology; ▪ Increased flexibility offers further incentives to customers in their evaluations of these types of investments; and ▪ Reduces system peak during the most expensive hours creating cost savings mutually shared by the customer and AE.

Rate Review Policy Guidelines

Austin Energy developed a series of policy goals and metrics as identified in Table 9.10 to serve as a guide for evaluating the reasonableness of this proposal and the new rates adopted during the public review process. These policy guidelines are intended to ensure that the utility satisfies its rate review objectives for financial strength and fair and equitable rates, among others.

Table 9.10
Rate Review Policy Goals and Metrics

Policy Goals	Metrics
Achieve Revenue Requirement	Revenues sufficient to fund core functions & strategic objectives.
Align with Cost of Service (minimize subsidies across customer classes)	No customer class pays greater than 105% or less than 95% of its cost of service.
Provide Affordable Energy (mitigate impacts within customer classes)	○ No residential customer electric bill below 1,500 kWh to increase by more than $20 per month on average. ○ Transition non-demand secondary commercial customers to demand rates.
Affordability Forecast Goal	System average rate increases of no more than 2% annually, after implementation of new rates and rate design.
Rate Benchmarking	Customer bills within the lowest 50% of comparable Texas utilities.
Customer Assistance Program	○ Increase funding by at least 100 percent to increase the numbers of customers receiving assistance. ○ Provide a Customer Assistance Program discount of $25 per month.
Achieve Long-Term Financial Stability	○ New rate design ensures utility's long-term financial strength & are in compliance with Financial Policies. ○ Improve recovery of Customer and Distribution fixed costs through fixed charge collection to at least 60%. ○ Maintains or improves credit ratings.
Maintain Renewable Energy Program Excellence (GreenChoice® & Solar)	○ Rate redesign retains national leadership position of GreenChoice®. ○ Continue solar incentives coupled with net metering rate redesign.

Achieve Revenue Requirement and Long-Term Financial Stability

Achieving the utility's revenue requirement helps ensure the utility's continued financial strength. Austin Energy is proposing an increase in rates based on the calculation of AE's Test Year revenue requirement and detailed in Table 9.1. As previously discussed, 17 of AE's largest commercial and industrial customers are served under special contract terms that run through May 2015. It is expected that current contract customers would be priced at the proposed rates once their contracts expire. Due to the terms of those contracts, AE will not collect its full annual revenue requirement until FY 2016. Until that time, the utility is projected to under-recover nearly $20 million a year.

Austin Energy is guided by financial policies set by the City Council to achieve certain specific strategic goals and assure the utility's long-term financial viability.

Table 9.11 and Table 9.12 present information on some of the utility's key financial policies. Table 9.11 shows AE's required debt service coverage ratio of at least 2.0 compared to projections. Results are shown for Test Year 2009, FY 2012 to represent the near-term recovery from proposed new rates, and FY 2016 assuming that rates are adjusted to price special contract customers at their cost of service once their contracts expire. These values are reflective of the Test Year 2009 cost structure and sales to each customer class. This shows that under the proposed rates, AE is projected to satisfy its 2.0 debt service coverage ratio requirement starting in 2012.

Table 9.11
Debt Service Coverage Based on Proposed Rates

Financial Policy	Goal	2009	2012	2016
Debt Service Coverage	At Minimum 2.00	1.58	2.24	2.37

Table 9.12 shows the three reserve funds specified in City Council policies that are currently unfunded. The proposed rates are designed to gradually fund these reserves over time based on annual contributions of approximately $22.7 million. This annual contribution is included as a use of cash in the margin calculation to provide future revenue for AE to replenish reserve levels given that available system revenues are applied to operation and maintenance expenses, debt service, capital improvement projects, General Fund transfer, and other operating costs that have priority over reserve contributions.

Table 9.12
Unfunded Reserve Requirements

Financial Policy	Goal	Test Year 2009 Reserve Requirements (in millions)
Repair and Replacement Fund ($)	1/2 of annual depreciation	61.2
Strategic Reserve Fund (Rate Stabilization Reserve)	90 days of net power supply cost	97.9
Non-Nuclear Plant Decommissioning Fund ($)	Sufficient funding to ensure funds are available for decommissioning expense	67.2

Align with Cost of Service

Aligning rates to the extent possible with cost of service ensures that customers pay their fair share for receiving electric services while minimizing inter-class subsidization. To maintain the affordability of electricity and meet other objectives such as providing a discount to low-income or other disadvantaged customers, rates may be set that deviate from cost of service. Given these considerations, AE has determined that it is reasonable to bound the revenue requirement by customer class such that no class pays greater than 105 percent or less than 95 percent of its cost of service, recognizing that the utility must also achieve its total revenue requirement. Table 9.6 shows the cost of service results versus proposed rates by customer class to reflect the cost re-distribution proposed by AE to help share the needed revenue increase among the customer classes.

Affordability Goal and Electric Rate Benchmarking

Austin Energy is also committed to maintaining the affordability of electricity in the community and has established goals to keep customer electric bills low and comparable to other customers around the State. On February 17, 2011, the City Council approved the utility's Resource Plan including an affordability goal. The affordability goal requires that AE operate so as to control rate (base, fuel, riders, etc.) increases to residential, commercial, and industrial customers to 2 percent or less per year. In addition, the goal is to maintain AE's current all-in competitive rates in the lower 50 percent of Texas rates. The affordability goal will be effective upon implementation of AE's new rates following this rate review.

Specifically for this rate review, AE has established goals for mitigating the impact of rate increases within customer classes by designing rates that prevent residential customer electric bills below 1,500 kWh from increasing by more than $20 a month on average and transitioning Secondary Voltage commercial customers currently not being assessed demand rates to demand rates. Increasing funding to the Customer Assistance Program will also help the most disadvantaged customers served by AE continue to afford electricity.

Rate benchmarking comparing AE's proposed rates with comparable Texas electric utilities is included at the end of Section 6 of this report for residential customers and at the end of Section 7 of this report for commercial and industrial customers.

Decision Point List

The decision point list is a list of key issues for consideration by the EUC in its review of this rate proposal. This list may be expanded during the course of the EUC review process as needed. The decision point list includes AE's recommendations and will later include the positions of participants in the EUC review process. This list serves as a framework for discussion of issues during the EUC review process and will ultimately memorialize the recommendations of AE, the EUC, and public participants for submission to the City Council. The draft decision point list is provided as Table 9.13.

Table 9.13
Austin Energy 2011 Rate Review
Decision Point List

Issue	Austin Energy Staff Recommendation[1]	Residential Rate Advisor	Other Parties	EUC
1) Achieve Revenue Requirement	Collect revenues from all customer classes sufficient to fund core functions and the utility's strategic objectives. Increase overall revenues based on the Test Year 2009 results from $1,004,133,897 to $1,111,135,775, or an 11.2% increase with this requested rate increase.			
2) Align Rates by Customer Class with Cost of Service (minimize subsidies across customer classes)	No customer class should pay greater than 105 percent or less than 95 percent of its cost of service in the implemented new rates, with the condition that the utility achieve its total revenue requirement through implemented rates with the exception of contract customers.			
3) Set Policy Bounds on Customer Class Alignment with Cost of Service	Set the Residential, Secondary Voltage <10 kW, and Lighting customer class target revenues at 95 percent of cost of service and set all other customer classes at 104 percent of cost of service.			
4) Mitigate Impacts Within Customer Classes	(a) No residential customer electric bill below 1,500 kWh should increase by more than $20 a month on average.			

[1] Preliminary; to be finalized for final proposal to the Austin City Council based on consideration of public input and input from the EUC.

Issue	Austin Energy Staff Recommendation[1]	Residential Rate Advisor	Other Parties	EUC
	(b) Transition non-demand secondary commercial customers to demand rates.			
5) Select a Production Demand Cost Allocation Method	Apply the Average and Excess Demand Method to 1) recognize that customers benefit from both capacity and energy produced from generation assets; 2) to reward high load factor and energy efficient customers; 3) to be consistent with methodologies commonly used in Texas and around the country.			
6) Consolidate Customer Classes	Consolidate current customer classes from 24 to 9 classes and develop classes based on cost of service differentials, including unique service requirements and electricity usage characteristics.			
7) Update Rate Structure for Residential Customers	Unbundle rates and apply a customer charge, electric delivery charge, energy charge, regulatory charge, community benefit charge, and energy adjustment.			
8) Update Rate Structure for Commercial and Industrial Customers	Unbundle rates and apply a customer charge, electric delivery charge, energy charge, demand charge, regulatory charge, community benefit charge, and energy adjustment.			
9) Update Fuel and Energy Market Costs Recovery Mechanism	Recover Test Year fuel-related costs in the energy charge and apply an energy adjustment in future years to account for future fluctuations in fuel-related and			

Issue	Austin Energy Staff Recommendation[1]	Residential Rate Advisor	Other Parties	EUC
	energy market costs.			
10) Apply Regulatory Charge	Add a regulatory charge to recover costs associated with transmission and ERCOT fees and remove these costs from the energy charge.			
11) Apply Community Benefit Charge	Add a community benefit charge to recover costs associated with the Customer Assistance Program, service area lighting, and energy efficiency programs and remove these costs from the energy charge.			
12) Update Summer Rate Period	Shorten summer rate period from six (May – October) to four months (June – September) so that stronger pricing signals can be provided during the summer time period and to align with ERCOT.			
13) Apply Residential Customer Charge	Raise the current residential customer charge from $6 to $15 and remove this portion of residential customer-related costs from the variable energy charge.			
14) Apply Residential Electric Delivery Charge	Move distribution costs from the energy charge to an electric delivery charge for residential customers set at $10 and remove this portion of residential distribution costs from the variable energy charge.			
15) Implement Residential Inclining Block Tiered Rate Structure for Energy Charge	Expand existing residential inclining block rate structure from two tiers to five tiers to provide stronger conservation and energy efficiency pricing signals to the			

Issue	Austin Energy Staff Recommendation[1]	Residential Rate Advisor	Other Parties	EUC
	highest users in the residential customer class.			
16) Fund Customer Assistance Program	Fund the Customer Assistance Program with a Community Benefit Charge sub-component of $0.00065/kWh to all customers.			
17) Apply Commercial and Industrial Customer Charge	Apply customer charge at or near cost of service for commercial and industrial customers.			
18) Apply Commercial and Industrial Electric Delivery Charge	Unbundle rates and apply an electric delivery charge on a $/kW basis at or near cost of service for all commercial and industrial customers.			
19) Apply Commercial and Industrial Demand Charge	Expand use of demand charges to all commercial and industrial customers and implement a three-year phase- in of demand-related charges (electric delivery and demand charge on a $/kW basis) for the current non-demand customers.			
20) Apply Power Factor Adjustment for Commercial and Industrial Customers	Apply a power factor adjustment of 90 percent to all commercial and industrial customers with the exception of current non-demand customers during the phase-in period and customers with demand less than 10 kW.			
21) Implement Time-of-Use Alternative Rates	Implement a time-of-use alternative rate for residential customers with a 2,000 customer enrollment cap and implement time-of-use rates for each commercial and industrial customer class with an enrollment			

Issue	Austin Energy Staff Recommendation[1]	Residential Rate Advisor	Other Parties	EUC
	cap of the higher of 10 percent of the customers in the class or 10 customers for each class.			
22) Update Renewable Energy Alternative Rate (GreenChoice®)	Maintain the GreenChoice alternative rate for customers who wish to receive a 100 percent renewable energy price that is locked in and use a bundled portfolio approach that prorates the GreenChoice adjustment to account for system-wide renewables.			
23) Update Net Metering Alternative Rate	Maintain a net metering rate for customers with distributed generation (e.g., solar PV) and apply a credit at the annual value of solar rate for excess energy generated on a monthly basis with the intent to move to a separate solar rate when meter data management capabilities are achieved.			
24) Update Thermal Energy Rate Option	Update existing thermal storage rate option to support customer investment in this technology.			
25) Plan for Pricing Pilot Projects with Pecan Street Project	Austin Energy will work with the Pecan Street Project to pilot new rates for customers. Any pilot project implemented must first be approved by the Austin City Council.			
26) Plan for Future Pricing of Long-Term Contract Customers	Move long-term contract customers to cost of service-based rates upon expiration of their contracts in 2015.			

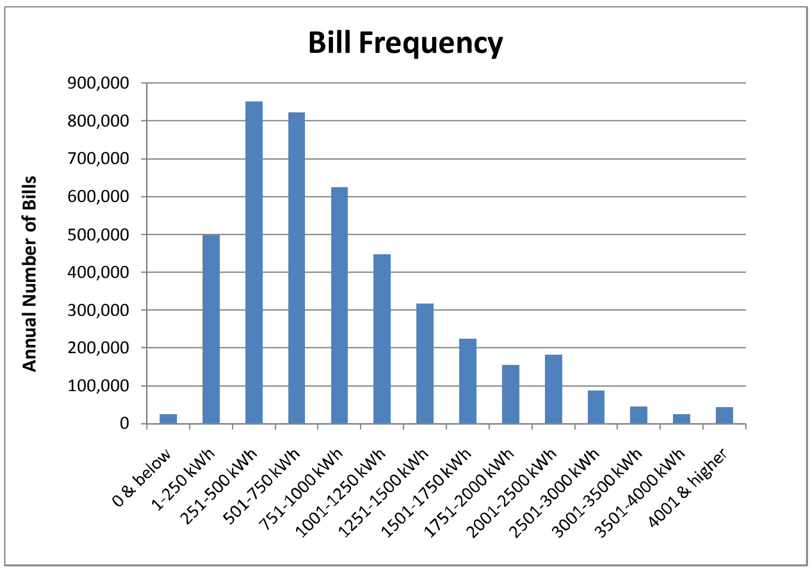
Appendix A: Customer Class Data

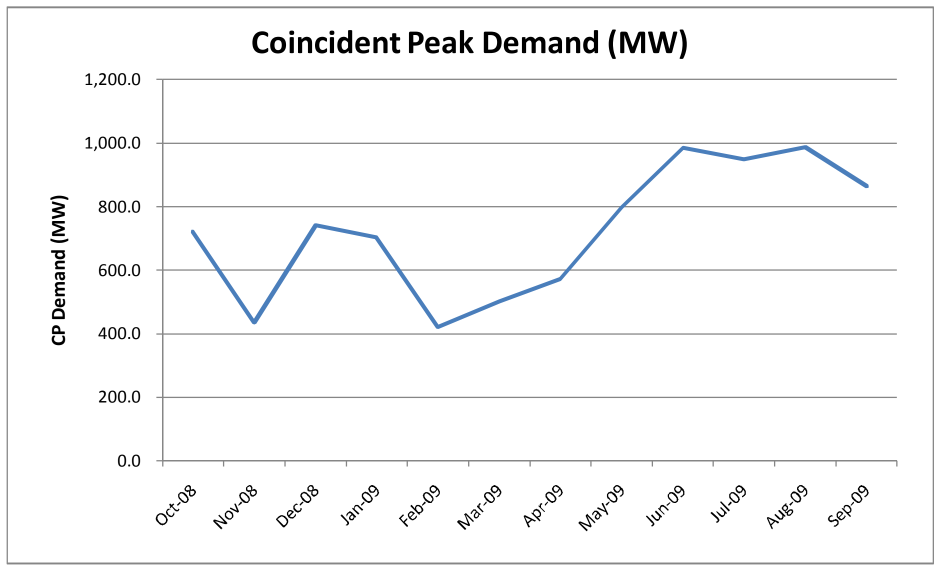
Austin Energy
Proposed Customer Class Summary Data
TY 2009

Customer Class:	Residential	
Class Code:	n/a	
Number of Bills		4,374,252
Annual Retail Energy Sales (kWh)		3,864,401,370
Annual Revenue	$	373,304,903
$/Bill	$	85.34
Cents/kWh		9.7
Average Monthly Energy Usage/Bill:		883 kWh
Average CP Demand/Customer:		2.7 kW
Average NCP Demand/Customer:		3.3 kW

		Non-Coincident Peak		Coincident Peak		Coincidence
Month	Energy (kWh)	Demand (kW)	Load Factor	Demand (kW)	Load Factor	Factor
Oct-08	307,370,188	824,475	0.511	721,770	0.583	0.875
Nov-08	247,344,362	587,383	0.577	434,852	0.779	0.740
Dec-08	286,750,943	820,849	0.479	740,612	0.530	0.902
Jan-09	301,784,066	744,569	0.555	703,324	0.588	0.945
Feb-09	217,794,271	582,298	0.512	421,460	0.708	0.724
Mar-09	259,953,993	642,352	0.554	502,716	0.708	0.783
Apr-09	254,363,327	713,733	0.488	572,625	0.609	0.802
May-09	370,571,311	921,022	0.551	797,669	0.636	0.866
Jun-09	471,019,567	1,121,800	0.575	985,778	0.655	0.879
Jul-09	487,711,315	1,049,605	0.637	949,479	0.704	0.905
Aug-09	524,149,759	1,194,076	0.601	987,789	0.727	0.827
Sep-09	341,166,379	995,358	0.470	865,301	0.540	0.869
TY 2009	4,069,979,479	1,194,076	0.389	987,789	0.470	0.827

Note: Highlighted NCP demand value indicates annual NCP demand. Highlighted CP demand value indicates contribution to annual system peak demand.





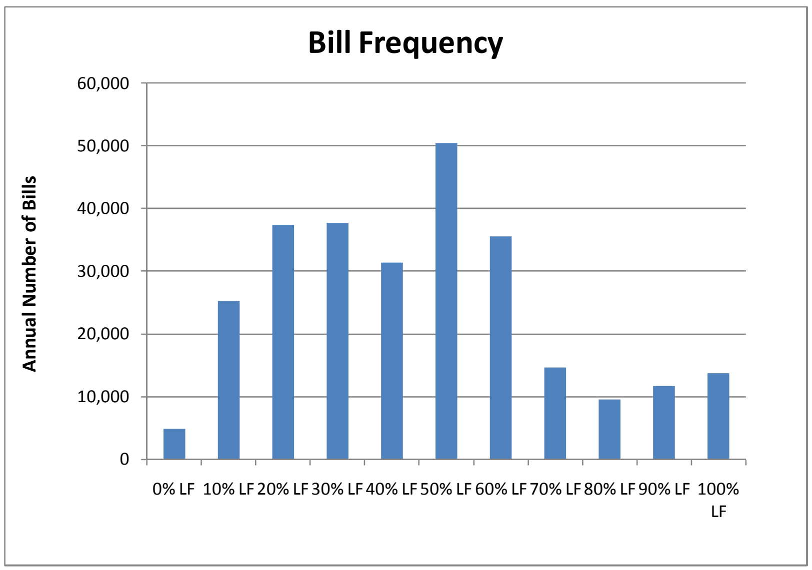
Austin Energy
Proposed Customer Class Summary Data
TY 2009

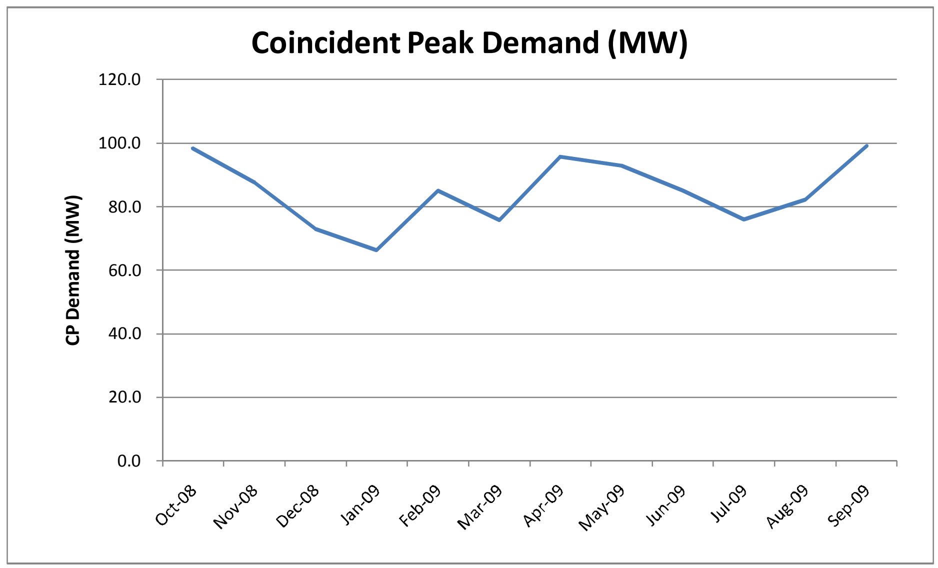
Customer Class: Secondary Voltage (< 10 kW)
Class Code: n/a

Number of Bills		384,008
Annual Retail Energy Sales (kWh)		378,885,207
Annual Revenue	$	36,421,201
$/Bill	$	94.84
Cents/kWh		9.6
Average Monthly Energy Usage/Bill:		987 kWh
Average CP Demand/Customer:		2.6 kW
Average NCP Demand/Customer:		3.1 kW

		Non-Coincident Peak		Coincident Peak		Coincidence
Month	Energy (kWh)	Demand (kW)	Load Factor	Demand (kW)	Load Factor	Factor
Oct-08	33,586,352	98,318	0.468	98,318	0.468	1.000
Nov-08	31,079,428	90,081	0.473	87,690	0.486	0.973
Dec-08	35,601,154	96,152	0.507	72,850	0.669	0.758
Jan-09	35,459,385	81,139	0.599	66,242	0.733	0.816
Feb-09	30,127,168	86,481	0.477	84,974	0.486	0.983
Mar-09	33,156,074	83,010	0.547	75,865	0.599	0.914
Apr-09	32,212,930	98,017	0.450	95,765	0.461	0.977
May-09	33,027,735	92,837	0.487	92,837	0.487	1.000
Jun-09	33,250,178	88,325	0.516	84,940	0.536	0.962
Jul-09	32,787,795	79,754	0.563	75,896	0.592	0.952
Aug-09	34,370,674	86,633	0.543	82,121	0.573	0.948
Sep-09	34,382,238	99,100	0.475	99,100	0.475	1.000
TY 2009	399,041,111	99,100	0.460	82,121	0.555	0.829

Note: Highlighted NCP demand value indicates annual NCP demand. Highlighted CP demand value indicates contribution to annual system peak demand.





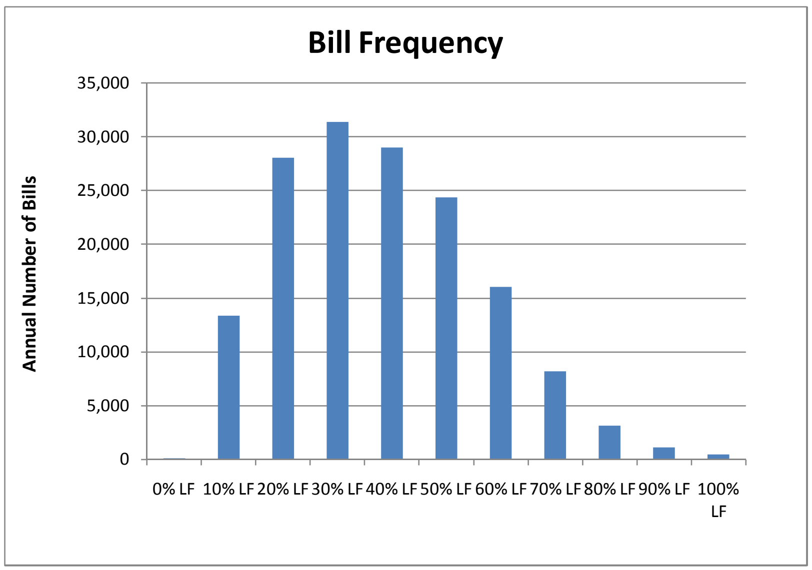
Austin Energy
Proposed Customer Class Summary Data
TY 2009

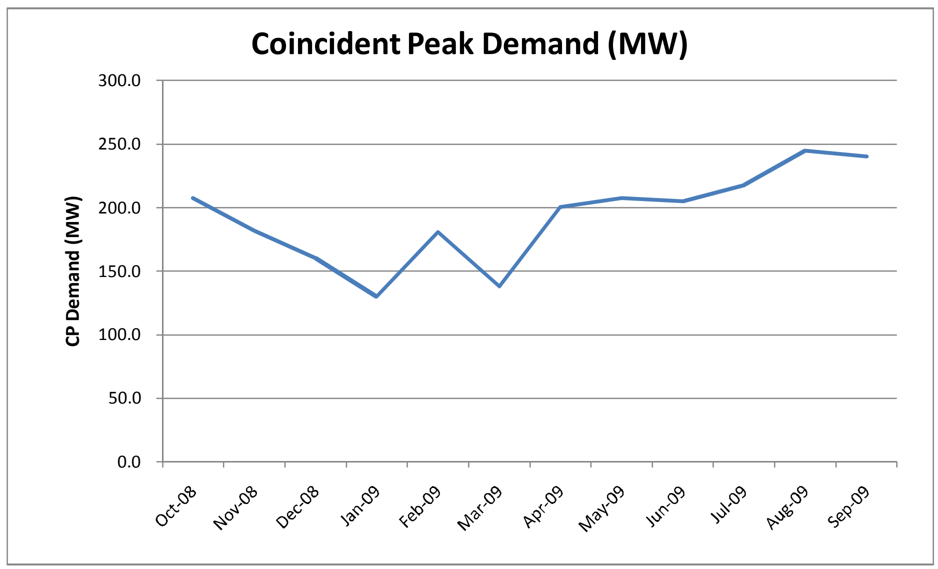
Customer Class: Secondary Voltage (≥ 10 < 50 kW)
Class Code: n/a

Number of Bills	124,321	
Annual Retail Energy Sales (kWh)	987,036,795	
Annual Revenue	$ 91,141,558	
$/Bill	$ 733.12	
Cents/kWh	9.2	
Average Monthly Energy Usage/Bill:	7,939	kWh
Average CP Demand/Customer:	23.6	kW
Average NCP Demand/Customer:	24.8	kW

		Non-Coincident Peak		Coincident Peak		Coincidence
Month	Energy (kWh)	Demand (kW)	Load Factor	Demand (kW)	Load Factor	Factor
Oct-08	85,109,147	214,806	0.543	207,547	0.562	0.966
Nov-08	71,042,266	187,056	0.520	181,709	0.536	0.971
Dec-08	85,067,482	173,001	0.674	160,104	0.728	0.925
Jan-09	79,319,744	148,670	0.731	129,771	0.837	0.873
Feb-09	70,671,135	183,364	0.528	180,723	0.536	0.986
Mar-09	72,397,327	164,513	0.603	138,131	0.718	0.840
Apr-09	76,617,158	210,515	0.499	200,432	0.524	0.952
May-09	90,996,880	224,752	0.555	207,427	0.601	0.923
Jun-09	95,906,141	213,111	0.616	205,070	0.641	0.962
Jul-09	108,122,244	227,155	0.652	217,566	0.681	0.958
Aug-09	111,967,308	250,028	0.613	244,672	0.627	0.979
Sep-09	92,328,266	257,114	0.492	240,122	0.527	0.934
TY 2009	1,039,545,098	257,114	0.462	244,672	0.485	0.952

Note: Highlighted NCP demand value indicates annual NCP demand. Highlighted CP demand value indicates contribution to annual system peak demand.





Austin Energy
Proposed Customer Class Summary Data
TY 2009

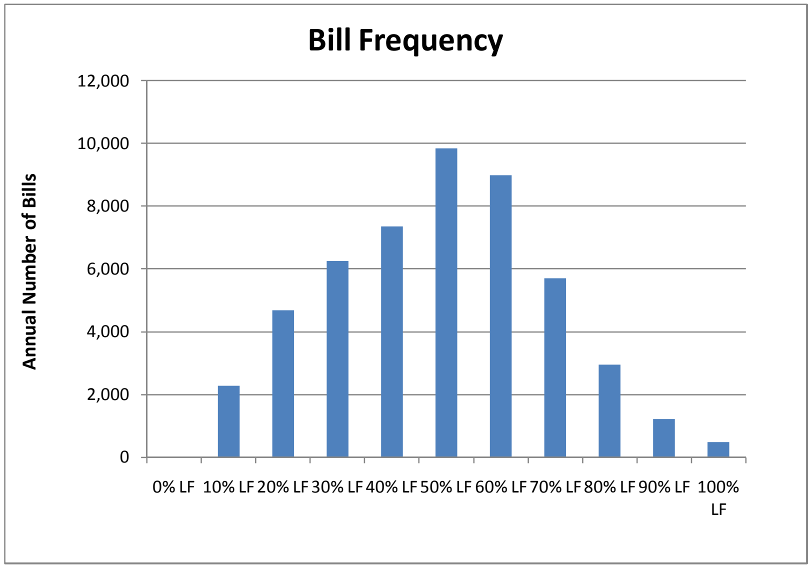
Customer Class: Secondary Voltage (≥ 50 kW)

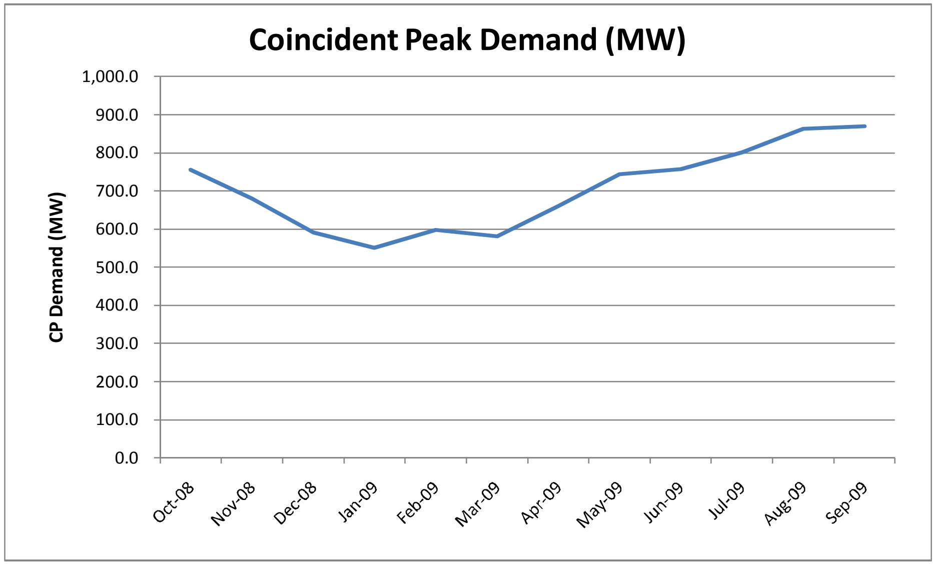
Class Code: n/a

Number of Bills	38,566	
Annual Retail Energy Sales (kWh)	4,142,609,008	
Annual Revenue	$ 349,970,012	
$/Bill	$ 9,074.48	
Cents/kWh	8.4	
Average Monthly Energy Usage/Bill:	107,415	kWh
Average CP Demand/Customer:	268.6	kW
Average NCP Demand/Customer:	283.0	kW

		Non-Coincident Peak		Coincident Peak		Coincidence
Month	Energy (kWh)	Demand (kW)	Load Factor	Demand (kW)	Load Factor	Factor
Oct-08	369,588,749	764,444	0.662	756,458	0.669	0.990
Nov-08	312,236,095	696,546	0.614	680,325	0.629	0.977
Dec-08	346,190,302	647,019	0.733	591,268	0.802	0.914
Jan-09	340,563,958	614,353	0.759	551,017	0.847	0.897
Feb-09	289,058,785	610,108	0.649	598,615	0.661	0.981
Mar-09	324,767,296	660,402	0.674	580,381	0.767	0.879
Apr-09	321,503,283	681,324	0.646	660,257	0.667	0.969
May-09	362,050,628	781,556	0.635	743,909	0.667	0.952
Jun-09	387,172,314	817,376	0.649	757,207	0.700	0.926
Jul-09	443,707,664	856,526	0.710	801,687	0.758	0.936
Aug-09	454,010,844	909,375	0.684	863,190	0.721	0.949
Sep-09	412,137,266	901,475	0.626	869,454	0.649	0.964
TY 2009	4,362,987,184	909,375	0.548	863,190	0.577	0.949

Note: Highlighted NCP demand value indicates annual NCP demand. Highlighted CP demand value indicates contribution to annual system peak demand.





Austin Energy
Proposed Customer Class Summary Data
TY 2009

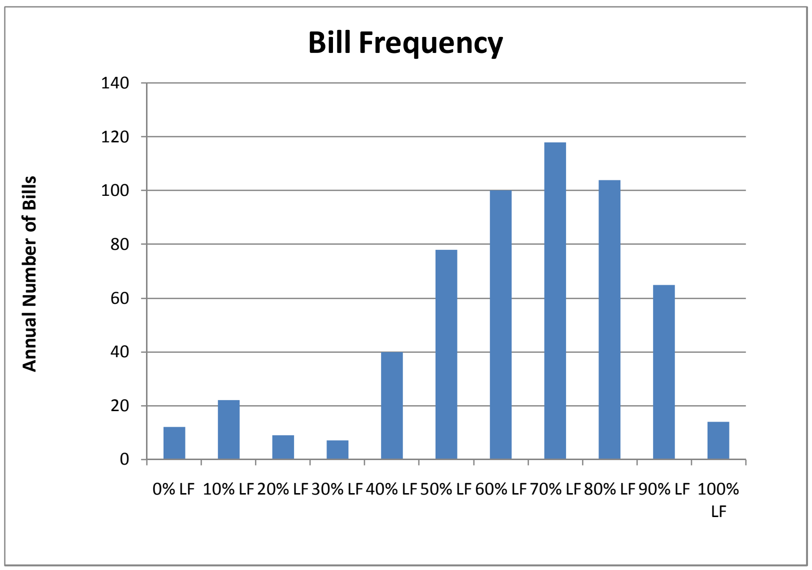
Customer Class: Primary Voltage (< 3 MW)

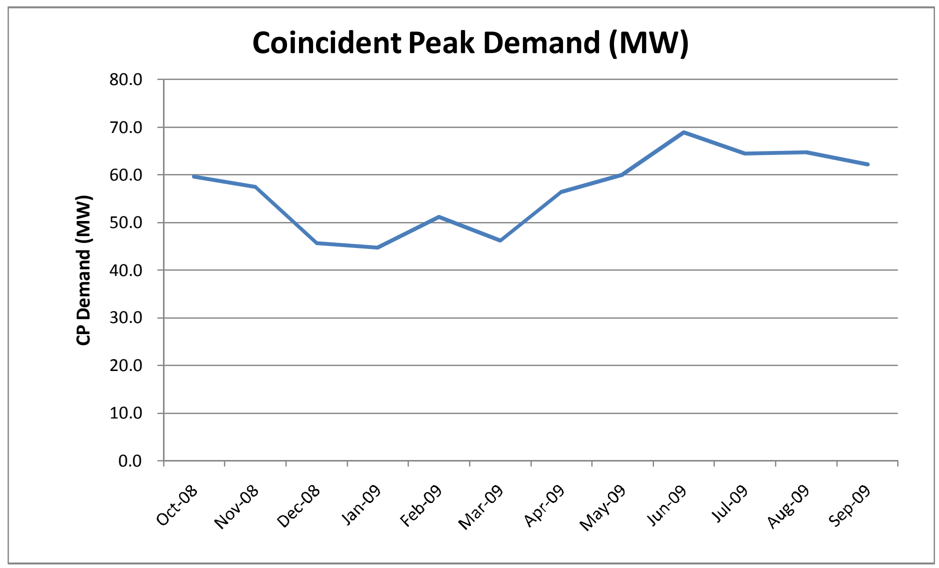
Class Code: n/a

Number of Bills	1,224	
Annual Retail Energy Sales (kWh)	405,947,626	
Annual Revenue	$ 30,377,964	
$/Bill	$ 24,818.60	
Cents/kWh	7.5	
Average Monthly Energy Usage/Bill:	331,657	kWh
Average CP Demand/Customer:	634.3	kW
Average NCP Demand/Customer:	694.3	kW

Month	Energy (kWh)	Non-Coincident Peak Demand (kW)	Non-Coincident Peak Load Factor	Coincident Peak Demand (kW)	Coincident Peak Load Factor	Coincidence Factor
Oct-08	35,381,857	59,869	0.810	59,650	0.813	0.996
Nov-08	31,154,022	57,519	0.742	57,519	0.742	1.000
Dec-08	31,077,361	51,243	0.831	45,701	0.932	0.892
Jan-09	29,972,570	48,441	0.848	44,690	0.919	0.923
Feb-09	27,787,378	53,082	0.717	51,178	0.744	0.964
Mar-09	32,071,564	52,257	0.841	46,187	0.951	0.884
Apr-09	32,364,092	57,624	0.769	56,428	0.786	0.979
May-09	36,843,676	61,574	0.820	60,031	0.841	0.975
Jun-09	39,361,712	68,852	0.783	68,852	0.783	1.000
Jul-09	43,766,140	70,815	0.847	64,503	0.929	0.911
Aug-09	41,882,880	68,082	0.843	64,703	0.887	0.950
Sep-09	36,193,665	62,330	0.795	62,171	0.797	0.997
TY 2009	417,856,916	70,815	0.674	64,703	0.737	0.914

Note: Highlighted NCP demand value indicates annual NCP demand. Highlighted CP demand value indicates contribution to annual system peak demand.





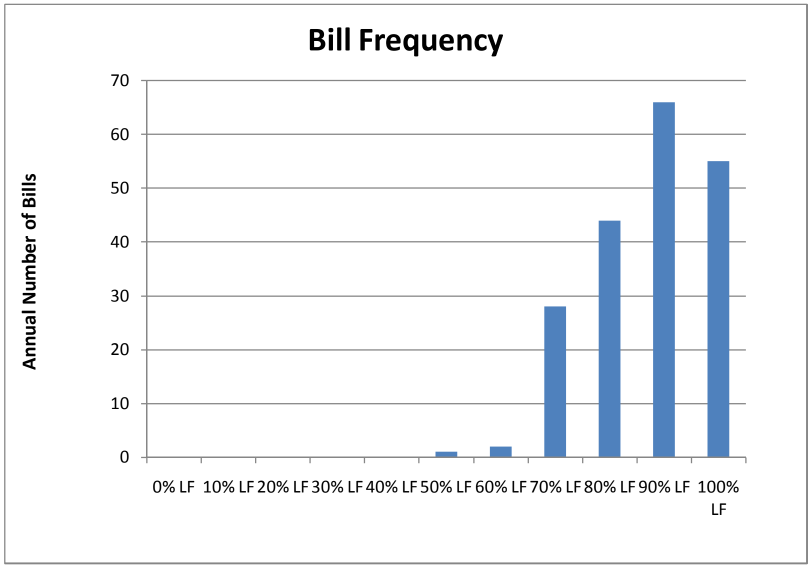
Austin Energy
Proposed Customer Class Summary Data
TY 2009

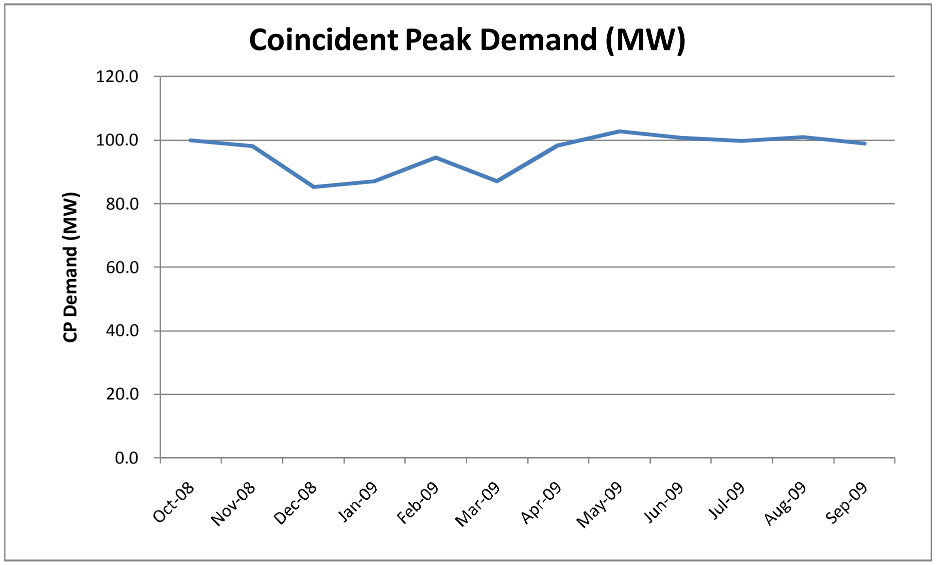
Customer Class: Primary Voltage (≥ 3 < 20 MW)
Class Code: n/a

Number of Bills	240	
Annual Retail Energy Sales (kWh)	769,829,965	
Annual Revenue	$ 47,083,898	
$/Bill	$ 196,182.91	
Cents/kWh	6.1	
Average Monthly Energy Usage/Bill:	3,207,625	kWh
Average CP Demand/Customer:	5,047.6	kW
Average NCP Demand/Customer:	5,504.1	kW

		Non-Coincident Peak		Coincident Peak		Coincidence
Month	Energy (kWh)	Demand (kW)	Load Factor	Demand (kW)	Load Factor	Factor
Oct-08	67,816,457	108,396	0.857	100,008	0.929	0.923
Nov-08	61,833,765	99,054	0.855	98,137	0.863	0.991
Dec-08	62,683,200	97,242	0.883	85,320	1.006	0.877
Jan-09	62,476,682	93,018	0.920	87,056	0.983	0.936
Feb-09	57,394,080	97,937	0.803	94,412	0.833	0.964
Mar-09	64,409,019	96,318	0.916	87,124	1.013	0.905
Apr-09	63,759,950	103,477	0.844	98,384	0.888	0.951
May-09	69,435,447	106,153	0.896	102,732	0.926	0.968
Jun-09	69,819,712	107,642	0.889	100,680	0.950	0.935
Jul-09	72,918,794	110,081	0.907	99,737	1.002	0.906
Aug-09	72,779,652	109,925	0.907	100,952	0.988	0.918
Sep-09	67,087,719	105,731	0.869	98,882	0.929	0.935
TY 2009	792,414,476	110,081	0.822	100,952	0.896	0.917

Note: Highlighted NCP demand value indicates annual NCP demand. Highlighted CP demand value indicates contribution to annual system peak demand.



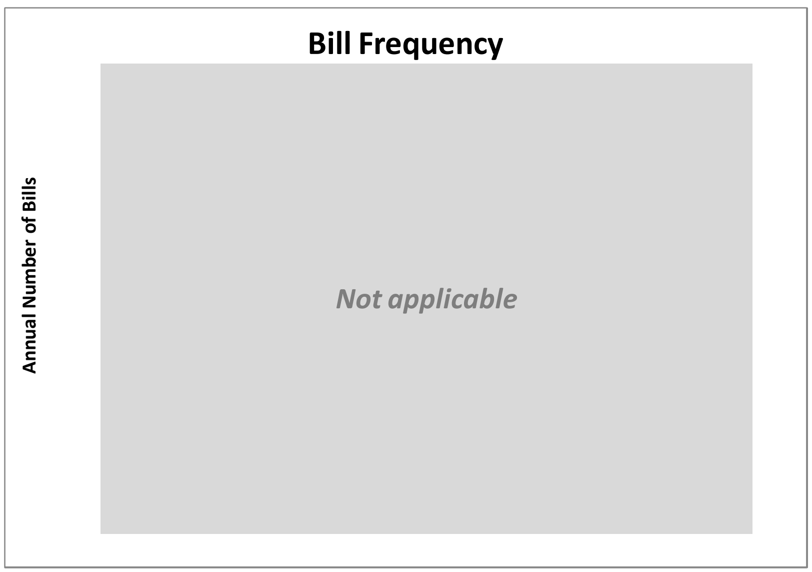


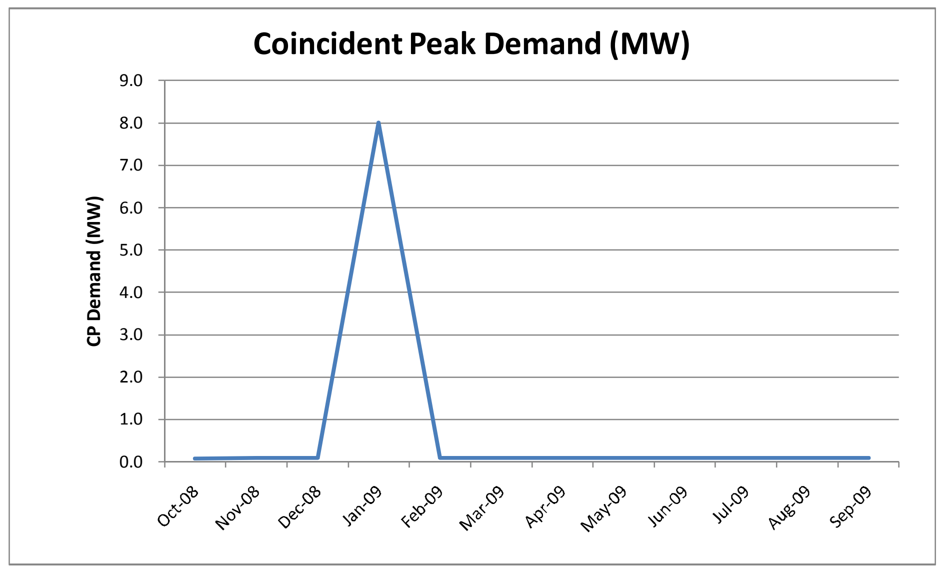
Austin Energy
Proposed Customer Class Summary Data
TY 2009

Customer Class:	Service Territory Street & Traffic Lights		
Class Code:	n/a		
Number of Bills	n/a		
Annual Retail Energy Sales (kWh)		31,713,621	
Annual Revenue	$	-	
$/Bill	n/a		
Cents/kWh	n/a		
Average Monthly Energy Usage/Bill:	n/a		kWh
Average CP Demand/Customer:			kW
Average NCP Demand/Customer:			kW

Month	Energy (kWh)	Non-Coincident Peak Demand (kW)	Non-Coincident Peak Load Factor	Coincident Peak Demand (kW)	Coincident Peak Load Factor	Coincidence Factor
Oct-08	3,040,728	8,688	0.479	82	50.974	0.009
Nov-08	3,243,637	8,948	0.497	87	51.033	0.010
Dec-08	3,606,822	9,340	0.529	90	55.119	0.010
Jan-09	3,486,677	9,164	0.521	8,013	0.596	0.874
Feb-09	2,799,797	8,936	0.429	93	41.322	0.010
Mar-09	2,994,542	9,375	0.438	89	46.318	0.009
Apr-09	2,613,807	9,263	0.387	92	39.086	0.010
May-09	2,336,423	9,470	0.338	92	34.649	0.010
Jun-09	2,151,486	9,246	0.319	93	31.606	0.010
Jul-09	2,113,283	8,766	0.330	88	32.972	0.010
Aug-09	2,421,341	8,945	0.371	90	36.753	0.010
Sep-09	2,592,179	8,604	0.413	87	40.803	0.010
TY 2009	33,400,720	9,470	0.403	90	42.249	0.010

Note: Highlighted NCP demand value indicates annual NCP demand. Highlighted CP demand value indicates contribution to annual system peak demand.



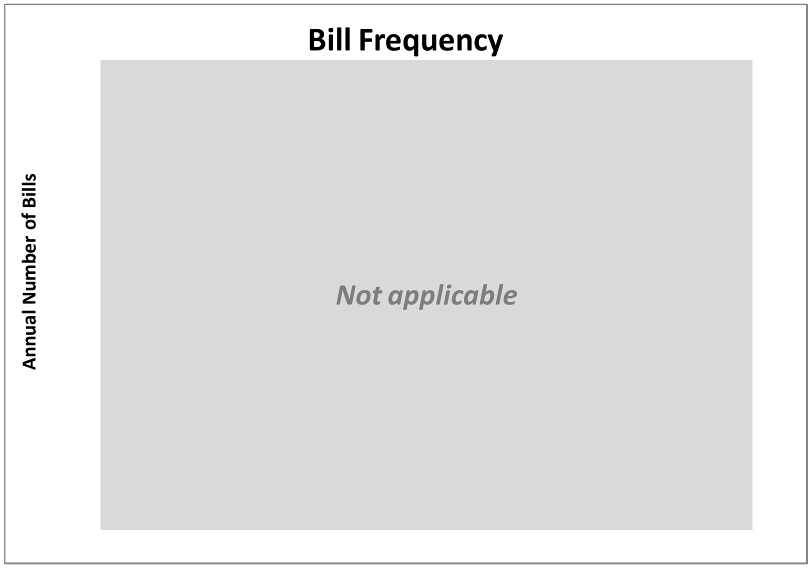


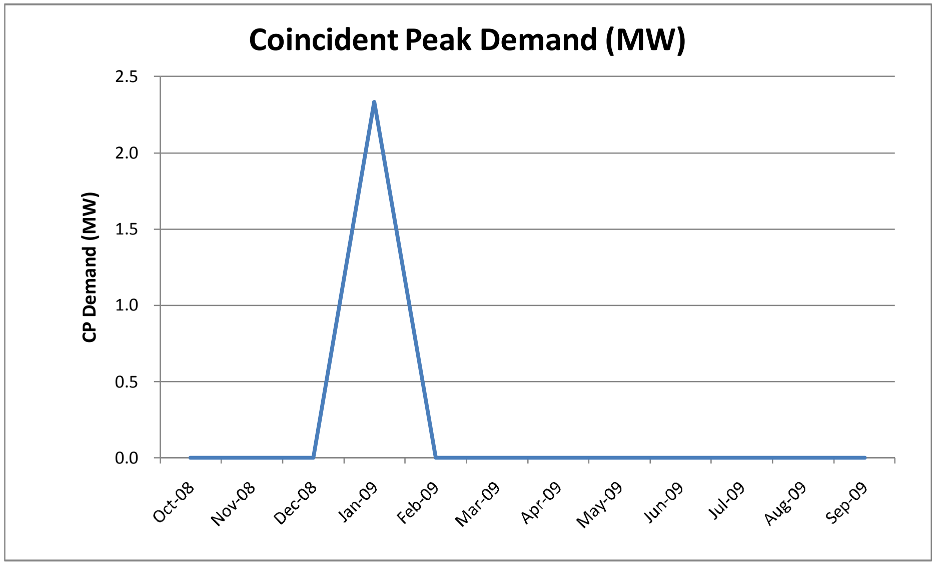
Austin Energy
Proposed Customer Class Summary Data
TY 2009

Customer Class:	City-Owned Private Outdoor Lighting (Security Lighting)
Class Code:	n/a
Number of Bills	n/a
Annual Retail Energy Sales (kWh)	11,564,634
Annual Revenue	$ 1,955,348
$/Bill	n/a
Cents/kWh	n/a
Average Monthly Energy Usage/Bill:	n/a kWh
Average CP Demand/Customer:	kW
Average NCP Demand/Customer:	kW

		Non-Coincident Peak		Coincident Peak		Coincidence
Month	Energy (kWh)	Demand (kW)	Load Factor	Demand (kW)	Load Factor	Factor
Oct-08	998,906	2,883	0.475	-	-	-
Nov-08	1,010,178	2,811	0.492	-	-	-
Dec-08	1,053,052	2,748	0.525	-	-	-
Jan-09	1,007,835	2,688	0.514	2,335	0.591	0.868
Feb-09	977,209	3,157	0.424	-	-	-
Mar-09	1,050,999	3,330	0.432	-	-	-
Apr-09	1,031,020	3,710	0.381	-	-	-
May-09	1,032,369	4,268	0.331	-	-	-
Jun-09	1,046,175	4,595	0.312	-	-	-
Jul-09	1,003,150	4,344	0.316	-	-	-
Aug-09	1,021,171	4,127	0.339	-	-	-
Sep-09	947,784	3,610	0.360	-	-	-
TY 2009	12,179,848	4,595	0.303	-	-	-

Note: Highlighted NCP demand value indicates annual NCP demand. Highlighted CP demand value indicates contribution to annual system peak demand.





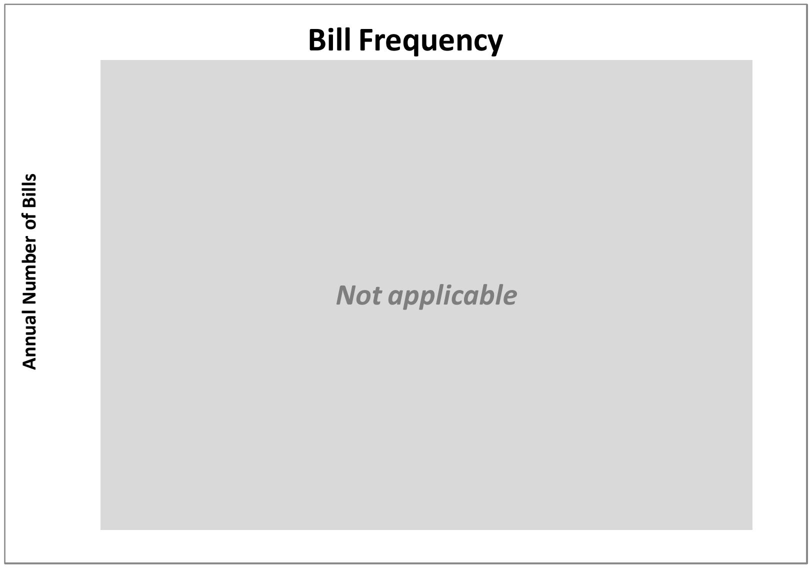
Austin Energy
Proposed Customer Class Summary Data
TY 2009

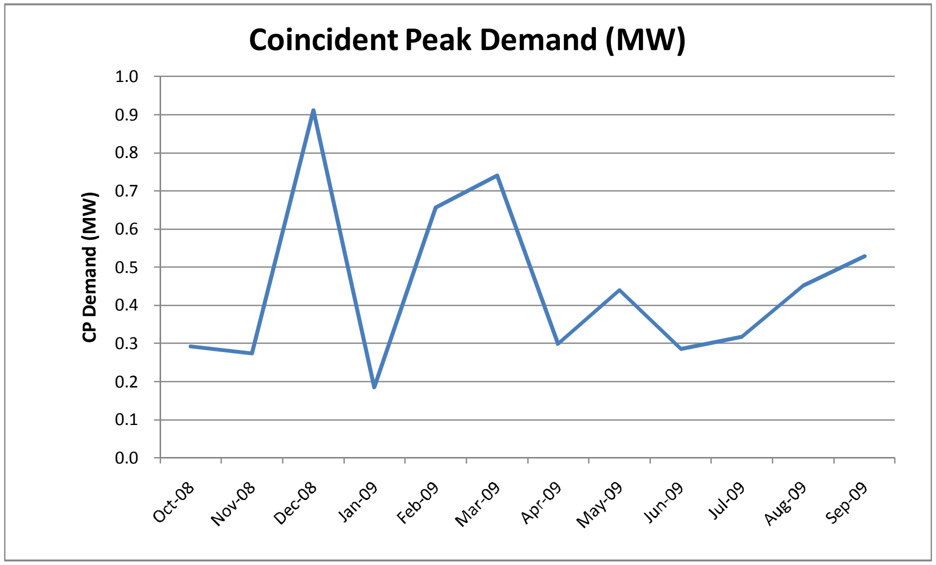
Customer Class: Customer-Owned, Metered (Sports Lighting)
Class Code: n/a

Number of Bills		473
Annual Retail Energy Sales (kWh)		4,359,820
Annual Revenue	$	375,924
$/Bill	$	795.23
Cents/kWh		8.6
Average Monthly Energy Usage/Bill:		9,223 kWh
Average CP Demand/Customer:		11.5 kW
Average NCP Demand/Customer:		106.3 kW

		Non-Coincident Peak		Coincident Peak		Coincidence
Month	Energy (kWh)	Demand (kW)	Load Factor	Demand (kW)	Load Factor	Factor
Oct-08	502,087	4,187	0.164	292	2.357	0.070
Nov-08	390,546	3,685	0.145	274	1.954	0.074
Dec-08	241,239	1,699	0.195	912	0.362	0.537
Jan-09	246,011	2,176	0.155	186	1.816	0.085
Feb-09	349,877	3,803	0.126	657	0.729	0.173
Mar-09	572,378	3,936	0.199	740	1.059	0.188
Apr-09	386,703	3,498	0.151	299	1.772	0.085
May-09	321,939	1,916	0.230	441	1.001	0.230
Jun-09	404,888	2,291	0.242	286	1.943	0.125
Jul-09	405,708	1,977	0.281	318	1.748	0.161
Aug-09	362,788	3,605	0.138	451	1.102	0.125
Sep-09	407,591	3,693	0.151	529	1.056	0.143
TY 2009	4,591,753	4,187	0.125	451	1.162	0.108

Note: Highlighted NCP demand value indicates annual NCP demand. Highlighted CP demand value indicates contribution to annual system peak demand.





Appendix B: Austin Energy Abridged Financial Policies and Bond Covenants

Appendix B
Austin Energy Abridged Financial Policies

- Debt and Debt Service
  - Debt shall not exceed the useful life of the asset and in no case shall the term exceed 30 years.
  - 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.
- Reserve Funding Requirements
  - 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.
  - Austin Energy shall maintain operating cash equivalent to 45 days of budgeted operation and maintenance expense.
  - A Repair and Replacement Fund shall be created and established. Money on deposit in the Repair and Replacement fund shall be used for providing extensions, additions, 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.
  - 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 operating cash.
    - Up to a maximum of 60 days additional cash set aside as a Contingency Reserve.
    - Any additional funds over the maximum 120 days of operating cash may be set aside in a Competitive Reserve.
  - A decommissioning trust shall be established external to the City to hold proceeds for moneys collected for the purpose of the decommissioning of the South Texas Nuclear Project.
  - 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 budget to achieve structural balance.
  - A non-nuclear plant decommissioning fund shall be established to fund plant retirement.
- Capital Structure
  - Short-term debt, including commercial paper, shall be used when authorized for interim financing of capital projects and fuel and material inventories. The term of short-term debt will not exceed 5 years.

  - Austin Energy shall maintain a quick ratio of 1.50X current assets less inventory divided by current liabilities.
  - Capital Projects should be financed through a combination of cash referred to as pay-as-you-go financing (equity contribution from current revenues) and debt, a ratio between 35% and 60% equity contribution is desirable.
- Cash Funding Requirements
  - Ongoing routine, preventive maintenance should be funded on a pay as you go basis.
  - 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.
- General Fund Transfer
  - The General Fund transfer shall not exceed 12% of AE's three-year average revenues, calculated using the current year estimate and the previous two year's actual revenues from the City's Comprehensive Annual Financial Report.
  - Electric rates shall be designed to generate sufficient revenue, after consideration of interest income and miscellaneous revenue, to support:
    - The full cost (direct and indirect) of operations including depreciation;
    - Debt service;
    - General Fund Transfer;
    - Equity funding of capital investments;
    - Requisite deposits of all reserve accounts;
    - Sufficient annual debt service requirements of the Parity Electric Utility Obligations and other bond covenant requirements; and
    - Any other current obligations.

In addition, AE may recommend to Council in the proposed budget directing excess net revenues for General Fund transfers, capital investment, repair and replacement, debt management, competitive strategies, and other AE requirements such as working capital. 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.

Appendix B
City of Austin Rate Covenant Required by Master Ordinance[1]

The City will fix, establish, maintain and collect such rates, charges and fees for electric power and energy and services furnished by the Electric Utility System and to the extent legally permissible, revise such rates, charges and fees to produce Gross Revenues each Fiscal Year sufficient: (i) to pay all current Operating Expenses; (ii) to produce Net Revenues, after (x) deducting amounts expended during the Fiscal Year from the Electric Utility System's Net Revenues for the payment of debt service requirements of the Prior First Lien Obligations and Prior Subordinate Lien Obligations and (y) taking into account ending fund balances in the System Fund to be carried forward in a Fiscal Year, equal to an amount sufficient to pay the annual debt service due and payable in such Fiscal Year of the then Outstanding Parity Electric Utility Obligations; and (iii) to pay after deducting the amounts determined in (i) and (ii) above, all other financial obligations of the Electric Utility System reasonably anticipated to be paid from Gross Revenues.

[1] City of Austin, Texas Official Statement, Electric Utility System Revenue Refunding Bonds, Series 2008A, page 6. July 24, 2008. Available online: **http://www.ci.austin.tx.us/finance/downloads/os_ae_rfg_08a.pdf**

Appendix C: Known and Measurable Adjustments

Test Year Development

Line No.		FERC Account	FY 2009 Actual	Adjustment	Test Year
A		B	C	D	E
1	**Power Production Expenses**				
2	Steam Power Generation				
3	**Operation**				
4	Operation Supervision and Engineering	500	$ 8,461,250	$ (549,563)	$ 7,911,687
5	Fuel - Recoverable	501	299,909,760	(168,380,271)	131,529,489
6	Fuel - Non-Recoverable	501	4,083,544	861,398	4,944,942
7	Steam Expenses	502	4,100,525	2,246,471	6,346,996
8	Steam from other Sources	503	-	-	-
9	Steam Transferred	504	-	-	-
10	Electric Expenses	505	5,013,588	(3,312,638)	1,700,950
11	Miscellaneous Steam Expenses	506	4,394,541	(195,307)	4,199,234
12	Rents	507	146	(146)	-
13			$ 325,963,353	$ (169,330,055)	$ 156,633,297
14					
15	**Maintenance**				
16	Maintenance Supervision	510	$ 2,273,086	$ 183,652	$ 2,456,738
17	Maintenance of Structures	511	215,751	11,503	227,254
18	Maintenance of Boiler Plant	512	6,356,222	(557,654)	5,798,568
19	Maintenance of Electric Plant	513	3,534,272	(511,592)	3,022,679
20	Maintenance of Miscellaneous Steam Plant	514	3,553,188	102,529	3,655,717
21	Rents	515	-	-	-
22			$ 15,932,519	$ (771,562)	$ 15,160,958
23					
24	Nuclear Power Generation				
25	**Operation**				
26	Operation Supervision	517	$ 9,211,756	$ (284,366)	$ 8,927,390
27	Nuclear Fuel Expense	518	16,866,183	2,480,877	19,347,060
28	Coolants and Water	519	953,232	83,777	1,037,009
29	Steam Expenses	520	1,458,922	501,905	1,960,827
30	Electric Expenses	523	4,134,216	191,435	4,325,651
31	Misc Nuclear Power Expenses	524	12,914,335	189,331	13,103,665
32	Rents	525	-	-	-
33			$ 45,538,644	$ 3,162,959	$ 48,701,602
34					
35	**Maintenance**				
36	Maintenance Supervision	528	$ 4,898,622	$ 1,152,420	$ 6,051,042
37	Maintenance of Structures	529	2,347,069	341,657	2,688,726
38	Maintenance of Reactor Plant	530	5,620,149	1,524,030	7,144,179
39	Maintenance of Electric Plant	531	2,852,587	713,296	3,565,883
40	Maintenance of Miscellaneous	532	662,509	86,131	748,640
41			$ 16,380,935	$ 3,817,533	$ 20,198,469
42					
43	Hydraulic Power Generation				
44	**Maintenance**				
45	Maintenance Supervision	541	$ -	$ -	$ -
46	Maintenance of Structures	542	-	-	-
47	Maintenance of Reservoirs, Dams & Waterways	543	-	-	-
48	Maintenance of Electric Plant	544	-	-	-
49	Maintenance of Miscellaneous Hydraulic Plant	545	-	-	-
50			$ -	$ -	$ -
51					
52	Other Power Generation				
53	**Operation**				
54	Operation Supervision	546	$ 2,356,493	$ 144,086	$ 2,500,579
55	Fuel	547	4,206	122,424,961	122,429,167
56	Generation Expenses	548	2,489,508	1,567,881	4,057,389
57	Miscellaneous Other Power Generation Expenses	549	130,467	203,125	333,592
58	Rents	550	205,134	72	205,206
59	Energy Efficiency		-	21,485,378	21,485,378
60	Green Building		-	1,881,981	1,881,981
61	Solar Rebate		-	4,352,770	4,352,770

Austin Energy
Electric Cost of Service

Test Year Development

Line No.		FERC Account	FY 2009 Actual	Adjustment	Test Year
A		B	C	D	E
62			$ 5,185,807	$ 152,060,254	$ 157,246,061
63					
64	**Maintenance**				
65	Maintenance Supervision and Engineering	551	$ 22,617	$ 20,596	$ 43,213
66	Maintenance of Structures	552	105,620	41,958	147,578
67	Maintenance of Generating and Electric Equipment	553	8,172,762	5,080,363	13,253,125
68	Maintenance of Misc Other Power Generation Plant	554	1,169,131	274,779	1,443,910
69			$ 9,470,131	$ 5,417,695	$ 14,887,826
70					
71	Other Power Supply				
72	Purchased Power - Recoverable	555	$ 78,830,176	$ 17,681,726	$ 96,511,902
73	Purchased Power - Non-Recoverable	555	26,856,820	(16,453,605)	10,403,215
74	System Control and Load Dispatching - Recoverable	556	12,791,041	8,288,917	21,079,958
75	System Control and Load Dispatching - Non-Recoverable	556	9,921,783	(8,118,813)	1,802,970
76	Other Power Expenses	557	461,942	27,851	489,793
77			$ 128,861,761	$ 1,426,076	$ 130,287,838
78					
79	**Total Power Production Expense**		**$ 547,333,150**	**$ (4,217,099)**	**$ 543,116,051**
80					
81	**Transmission Expense**				
82	**Operation**				
83	Operations Supervision and Engineering	560	$ 4,139,800	$ 993,366	$ 5,133,166
84	Load Dispatching	561	1,581,229	51,394	1,632,624
85	Station Expenses	562	181,382	204,001	385,383
86	Overhead Line Expenses	563	291,702	867,736	1,159,438
87	Underground Line Expenses	564	(189)	189	-
88	Transmission of Electricity by Others	565	58,477,601	7,437,651	65,915,251
89	Miscellaneous Transmission Expenses	566	589,653	16,525	606,178
90	Rents	567	3,000	-	3,000
91			$ 65,264,177	$ 9,570,863	$ 74,835,040
92					
93	**Maintenance**				
94	Maintenance Supervision and Engineering	568	$ 343,997	$ 740	$ 344,737
95	Maintenance of Structures	569	22,031	8,204	30,235
96	Maintenance of Station Equipment	570	(57,698)	1,310,874	1,253,176
97	Maintenance of Overhead Lines	571	1,286,533	18,788	1,305,322
98	Maintenance of Underground Lines	572	36,353	-	36,353
99	Maintenance of Miscellaneous Transmission Plant	573	17,866	(3,406)	14,460
100			$ 1,649,083	$ 1,335,200	$ 2,984,283
101					
102	**Total Transmission Expenses**		**$ 66,913,260**	**$ 10,906,062**	**$ 77,819,322**
103					
104	**Distribution Expenses**				
105	**Operation**				
106	Operations Supervision and Engineering	580	$ 8,214,447	$ (368,022)	$ 7,846,426
107	Load Dispatching	581	2,167,575	(6,429)	2,161,146
108	Station Expenses	582	1,189,288	25,751	1,215,039
109	Overhead Line Expenses	583	2,985,415	5,162,113	8,147,529
110	Underground Line Expenses	584	(674,154)	3,802,454	3,128,300
111	Street Lighting	585	104,565	284,590	389,156
112	Meter Expenses	586	3,931,002	(667,185)	3,263,817
113	Customer Installation Expenses	587	135,513	-	135,513
114	Miscellaneous Distribution Expenses	588	3,176,834	864,771	4,041,605
115	Rents	589	(507)	1,134	627
116			$ 21,229,979	$ 9,099,177	$ 30,329,157
117					
118	**Maintenance**				
119	Maintenance Supervision and Engineering	590	$ 137,125	$ 10,150	$ 147,276
120	Maintenance of Structures	591	104,947	-	104,947
121	Maintenance of Station Equipment	592	2,551,043	372,256	2,923,299
122	Maintenance of Overhead Lines	593	12,378,588	113,345	12,491,933

Test Year Development

Line No.		FERC Account		FY 2009 Actual		Adjustment		Test Year
A		B		C		D		E
123	Maintenance of Underground Lines	594		157,935		41,985		199,921
124	Maintenance of Line Transformers	595		6,916		1,571		8,487
125	Maintenance of Street Lighting and Signal Systems	596		1,382,155		119,181		1,501,335
126	Maintenance of Meters	597		68,127		11,868		79,995
127	Maintenance of Miscellaneous Distribution Plant	598		1,141,171		114,999		1,256,171
128			$	17,928,007	$	785,355	$	18,713,363
129								
130	**Total Distribution Expenses**		**$**	**39,157,987**	**$**	**9,884,532**	**$**	**49,042,519**
131								
132	**Customer and Information Expenses**							
133								
134	Customer Accounts Expenses							
135	Supervision	901	$	201,021	$	(91,590)	$	109,431
136	Meter Reading Expenses	902		11,108,833		3,182,273		14,291,107
137	Customer Records and Collection Expenses	903		27,215,210		532,564		27,747,774
138	Uncollectible Accounts	904		3,649,195		1,020,593		4,669,787
139	Miscellaneous Customer Accounts Expenses	905		(15,251,452)		(1,076,085)		(16,327,537)
140			$	26,922,807	$	3,567,755	$	30,490,562
141								
142	Cust. Service & Information Expense							
143	Supervision	907	$	3,237,337	$	(3,063,051)	$	174,286
144	Customer Assistance Expenses	908		22,959,873		(22,719,227)		240,646
145	Informational & Instructional Advertising Expenses	909		1,022,743		(934,167)		88,576
146	Misc Customer Service & Informational Expenses	910		750,929		(409,512)		341,418
147	Supervision	911		8,324,843		1,815,709		10,140,552
148	Demonstrating & Selling Expense	912		3,222,289		141,458		3,363,747
149	Advertising Expense	913		448,021		41,513		489,534
150	Miscellaneous Sales Expense	916		452,925		(126,236)		326,690
151			$	40,418,960	$	(25,253,512)	$	15,165,448
152								
153	**Total Customer and Information Expenses**		**$**	**67,341,767**	**$**	**(21,685,757)**	**$**	**45,656,010**
154								
155	**General and Administrative Expenses**							
156	Administrative and General Salaries	920	$	38,780,376	$	(7,889,227)	$	30,891,148
157	Office Supplies and Expenses	921		28,007,506		(7,511,597)		20,495,909
158	Administrative Expense Transferred	922		(287,411)		1,251,992		964,581
159	Outside Services Employed	923		10,565,986		(590,886)		9,975,100
160	Property Insurance	924		683,345		2,209,713		2,893,058
161	Injuries and Damages	925		4,073,967		(1,110,247)		2,963,720
162	Employee Pension and Benefits	926		29,056,796		(18,675,215)		10,381,582
163	Regulatory Commission Expense	928		-		1,292,907		1,292,907
164	General Expenses	930		22,428,040		(957,173)		21,470,867
165	Rents	931		1,607,142		517,778		2,124,920
166	Maintenance of General Plant	935		879,615		67,403		947,017
167			$	135,795,362	$	(31,394,553)	$	104,400,808
168								
169	**Total Operations & Maintenance Expenses**		**$**	**856,541,526**	**$**	**(36,506,815)**	**$**	**820,034,711**
170								
171	**Depreciation & Amortization of CIAC**							
172	Depreciation Expense	403	$	114,171,721	$	8,223,622	$	122,395,343
173	Amortization of CIAC			(5,180,831)		-		(5,180,831)
174			**$**	**108,990,890**	**$**	**8,223,622**	**$**	**117,214,512**
175								
176	**Debt Service**		**$**	**176,919,813**	**$**	**(8,849,523)**	**$**	**168,070,290**
177								
178	**General Fund Transfer**	421.5	**$**	**95,000,000**	**$**	**8,000,000**	**$**	**103,000,000**
179								
180	**Margin (as defined below)**		**$**	**26,277,668**	**$**	**(17,320,250)**	**$**	**8,957,418**
181								
182	**Sub-Total Revenue Requirement**		**$**	**1,263,729,897**	**$**	**(46,452,965)**	**$**	**1,217,276,931**

Test Year Development

Line No.		FERC Account	FY 2009 Actual	Adjustment	Test Year
A		B	C	D	E
183					
184	**Other Expenses**				
185	Misc Service Revenue	451	$ 22,056	$ 7,353	$ 29,409
186	Donations	426	38,342	3,011	41,353
187	Taxes Other Than Income	408	9,117	17,405	26,522
188	Expenses - Non-utility operations	417	16,288,944	(13,957,256)	2,331,688
189	Franchise Fees		-	1,123,778	1,123,778
190			**$ 16,358,459**	**$ (12,805,709)**	**$ 3,552,750**
191					
192	**Other (Non-Rate) Revenue**				
193	Miscellaneous Nonoperating Income	421	$ 5,177	$ -	$ 5,177
194	Other Revenue		106,808,816	(22,005,115)	84,803,701
195	Off-System Sales		16,877,957	(16,877,957)	-
196			**$ 123,691,950**	**$ (38,883,072)**	**$ 84,808,878**
197					
198	**Total Revenue Requirement**		**$ 1,156,396,406**	**$ (20,375,603)**	**$ 1,136,020,803**
199					
200	**System Retail Sales (MWh)**		**12,076,915**	**(262,976)**	**11,813,939**
201	Average Rate ($/MWh)		$ 95.75		$ 96.16
202					
203	**Comparison to Rate Revenue - FY 2009 Rate Structure**				
204	Base Revenue		$ 614,797,276	$ (10,540,448)	$ 604,256,828
205	Recoverable Fuel		408,401,366	(17,503,790)	390,897,575
206	Green Choice		31,683,294	(21,626,212)	10,057,082
207	Remove Service Area Street Lighting Fuel Cost		-	(1,077,588)	(1,077,588)
208			**$ 1,054,881,935**	**$ (50,748,038)**	**$ 1,004,133,897**
209					
210					
211	**Over / (Under) Recovery**		**$ (101,514,471)**	**$ (30,372,435)**	**$ (131,886,905)**
212					
213	*Required Increase / (Decrease) in Rate Revenue*		*9.6%*		*13.1%*
214					
215					
216	**Recoverable Fuel Cost**				
217	Fuel	501	$ 299,909,760	$ (168,380,271)	$ 131,529,489
218	Nuclear Fuel Expense	518	16,866,183	2,480,877	19,347,060
219	Fuel	547	4,206	122,424,961	122,429,167
220	Purchased Power	555	78,830,176	17,681,726	96,511,902
221	System Control and Load Dispatching	556	12,791,041	8,288,917	21,079,958
222			$ 408,401,366	$ (17,503,790)	$ 390,897,575
223					
224	**Off-System Sales**		$ 21,657,426	$ (21,657,426)	$ -
225					
226	**Net Cost to AE**		**$ 386,743,940**	**$ 4,153,635**	**$ 390,897,575**
227					
228					
229	**Margin Calculation**				
230	**Cash Sources**				
231	Depreciation Expense	403	$ 114,171,721	$ 8,223,622	$ 122,395,343
232	Amortization of CIAC		(5,180,831)	-	(5,180,831)
233	Interest and Dividend Income	419	17,401,562	(9,804,953)	7,596,609
234			$ 126,392,452	$ (1,581,332)	$ 124,811,121
235					
236	**Cash Uses**				
237	Capital From Current Revenue		$ 152,670,120	$ (41,579,109)	$ 111,091,011
238	Required Contributions to Decommissioning Reserves		-	6,716,995	6,716,995
239	Required Contributions to Reserves		-	15,960,533	15,960,533
240			$ 152,670,120	$ (18,901,581)	$ 133,768,539
241					
242	**Required Margin**		**$ 26,277,668**	**$ (17,320,250)**	**$ 8,957,418**

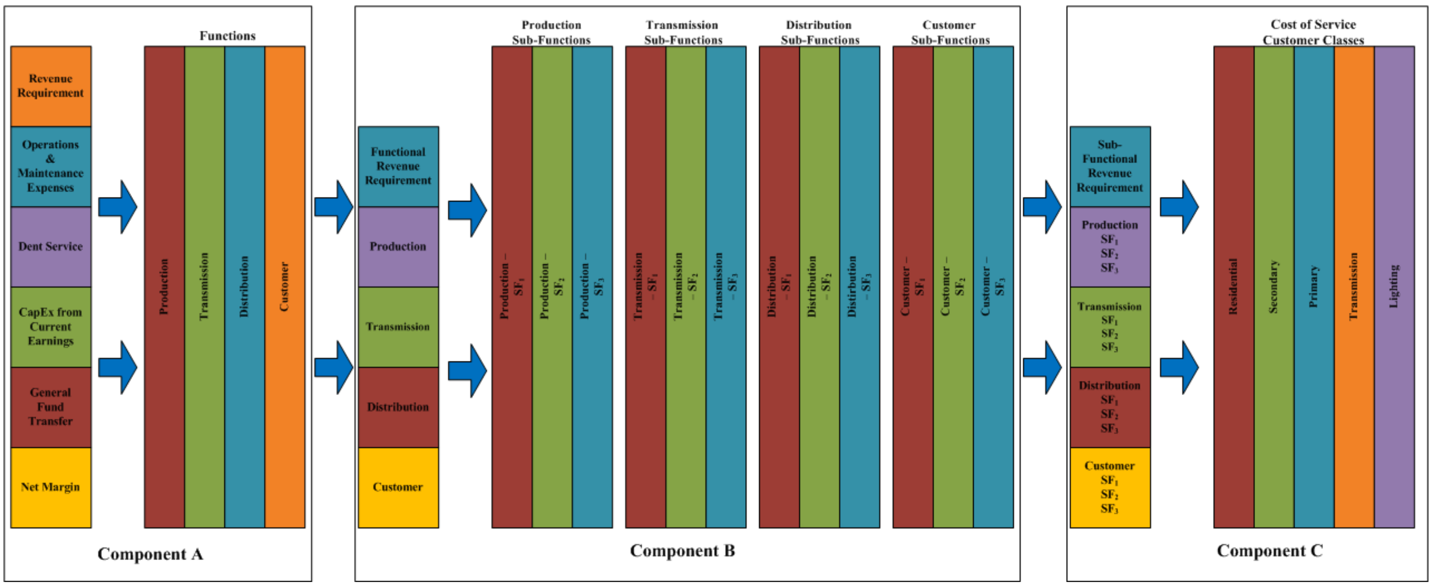
Test Year Development

Line No.		FERC Account	FY 2009 Actual	Adjustment	Test Year
A		B	C	D	E
243					
244					
245	**Debt Service Coverage Ratio (DSCR)**				
246	Rate Revenue (assuming required rate increase in Test Year)		$ 1,054,881,935	$ 81,138,867	$ 1,136,020,803
247	Other Operating & Non-Operating Revenue		123,691,950	(38,883,072)	84,808,878
248			$ 1,178,573,885	$ 42,255,796	$ 1,220,829,681
249					
250	Operations & Maintenance		$ 856,541,526	$ (36,506,815)	$ 820,034,711
251	Other Expenses		16,358,459	(12,805,709)	3,552,750
252	Non-Revenue Bonds at 1.0x DSCR		337,085	19,748	356,833
253			$ 873,237,069	$ (49,292,776)	$ 823,944,294
254					
255	**Balance Available for Revenue Debt Service**		**$ 305,336,816**	**$ 91,548,572**	**$ 396,885,388**
256					
257	Revenue Debt Service		$ 176,582,728	$ (8,869,271)	$ 167,713,457
258					
259	Revenue Debt Coverage Ratio		**1.73**	**0.64**	**2.37**
260					
261	**Additional Funds Required to Meet 2.0 DSCR Financial Policy**		**$ 47,828,640**	**$ (47,828,640)**	**$ -**
262					
263					
264	**Required Reserve Fund Balance**		**$ 442,237,000**	**$ (141,515,026)**	**$ 300,721,974**
265	(excludes restricted reserves for decommissioning and debt as well as deposits)				
266					
267	**Working Capital Reserve Fund**		$ 51,343,997	$ 323,407	$ 51,667,404
268	*Target: 45 days of O&M less fuel and purchased power*		*$ 51,343,997*	*$ 323,407*	*$ 51,667,404*
269					
270	Subtotal Reserves Funds after Working Capital Reserve Fund		$ 390,893,003	$ (141,838,433)	$ 249,054,570
271					
272	**Strategic Reserve Fund**				
273	Contingency Reserve Fund		$ 68,458,663	$ 431,209	$ 68,889,872
274	*Target: 60 days of O&M less fuel and purchased power*		*$ 68,458,663*	*$ 431,209*	*$ 68,889,872*
275	Emergency Reserve Fund		$ 68,458,663	$ 431,209	$ 68,889,872
276	*Target: 60 days of O&M less fuel and purchased power*		*$ 68,458,663*	*$ 431,209*	*$ 68,889,872*
277	Rate Stabilization Fund		$ 109,030,479	$ (11,071,725)	$ 97,958,754
278	*Target: 90 days of Power Cost (Net of ERCOT Fees)*		*$ 109,030,479*	*$ (11,071,725)*	*$ 97,958,754*
279	Subtotal Strategic Reserve Fund		$ 245,947,805	$ (10,209,307)	$ 235,738,498
280					
281	Subtotal Reserves Funds after Strategic Reserve Fund		$ 144,945,198	$ (131,629,125)	$ 13,316,072
282					
283	**Repair and Replacement Fund**		$ 57,085,861	$ (43,769,788)	$ 13,316,072
284	*Target: 1/2 of annual depreciation*		*$ 57,085,861*	*$ 4,111,811*	*$ 61,197,672*
285					
286	Subtotal Reserves Funds after Repair and Replacement Fund		$ 87,859,337	$ (87,859,337)	$ -
287					
288	Total Reserves		$ 442,237,000	$ (141,515,026)	$ 300,721,974
289	Total Reserve Requirements		$ 354,377,663	$ (5,774,090)	$ 348,603,573
290	Undesignated/Unrestricted Reserve		$ 87,859,337	$ (87,859,337)	
291	Reserve Deficiency			$ 47,881,599	$ 47,881,599

Appendix D: Cost of Service Model

Appendix D – Electric Cost of Service provides the detailed analyses supporting the cost of service. The cost of service analysis consists of three interconnected components which are graphically depicted and described below.

Cost of Service Model Overview



Component A – Functional Unbundling (Pages 9 to 49)

This component provides detailed descriptions of AE's revenue requirement. FY 2009 accounting information is provided by FERC account number or other applicable identifier (Column B – FERC Account and Column D – FY 2009 Actual). For each item, if adjusted, the amount of the adjustment is identified with an associated work paper (header for Columns N through AW). Test Year Adjustments are summarized by type in Section 3 of the Final Report. For each item, the TY value is simply the sum of the FY 2009 plus the adjustment factor (Column E). Once the detailed TY revenue requirement has been established the amount was assigned to the production, transmission, distribution, and customer functions. Assignments were made either through direct assignments or other allocation methodology. Allocation factors are identified under Column H – Allocation Basis. Specific allocation factors can be found starting on line number 295. The results of the Component A analyses for each function is the Austin Energy TY revenue requirement expressed on a functional basis, pages 17 to 21, Columns I to L.

Component B – Sub-functional Unbundling (Pages 50 to 114)

This component sub-functionalizes the production, transmission, distribution, and customer functions developed in Component A. Additionally, costs are classified as either demand-related, energy-related, customer related, or a direct assignment. Sub-functionalization is accomplished either through direct assignments or other allocation methodology. For each item, allocation factors are identified under Column E – Allocation Basis. Specific allocation factors can be found at the bottom of each sub-function worksheet (and are summarized in the Allocation List, pages 3 to 8). The results of the Component B analyses is the Austin Energy TY 2009 revenue requirement expressed on a sub-functional basis for each cost classification: Production function pages 50 to 88, Columns F to V; Transmission function pages 89 to 94, Columns F to I; Distribution function pages 95 to 108, Columns F to M; Customer function pages 109 to 114, Columns F to K.

Component C – Allocated Cost of Service (Pages 115 to 124)

Using the information developed under Component B, the Test Year 2009 sub-functionalized and classified revenue requirement was allocated to each of the proposed rate classes using allocation methodologies described in the Final Report. Specific allocation factors can be found starting on line number 98. For each item, allocation factors are identified under Column E – Allocation Basis. The result of the Component C analyses is the allocated cost of service for each customer class Columns F to Q. These results are summarized in Section 4, Table 4.20 of the Final Report.

Work Papers

Work Papers 1 through 45 support adjustments and allocations used in Components A, B, and C. These work papers can be found on pages 145 to 296.

Table of Contents

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Source Documents

	File Name	Description	Work Papers Referenced				
SD-1	FA FY2009 - Updated.xls	Plant In Service by FERC at the End of FY 2009	WP 1 - Trial Balance	WP 2 - Plant	WP 2.1 - Plant	WP 2.2 - Plant	WP 26 - Prod Plant
SD-2	FS_Sep_09P13.xls	Financial Statements for FY 2009	WP 1 - Trial Balance				
SD-3	I_S_BY_FERC_09.xls	Detailed Income Statement by FERC for FY 2009	WP 1 - Trial Balance				
SD-4	Retirements FY 2010.xls	Plant In Service Retirements in FY 2010 by FERC	WP 2.1 - Plant	WP 26 - Prod Plant			
SD-5	New Projects Updated.xls	Summary of Spending to Date on Selected New Projects	WP 2.3 - Plant				
SD-6	3.Q 5 Year CIP Spending Plan.xls	Five-Year Capital Improvement Plan	WP 2.3 - Plant	WP 14 - CIP			
SD-7	New Meters.doc	Automated Meter Investment Cost and Useful Life Assumption	WP 2.3 - Plant				
SD-8	Close II FERC Power Plant.xls	Generation FERC Detail (Fuel and Non-Fuel)	WP 3.1 - Labor	WP 16 - Fuel	WP 24 - Prod O&M	WP 44 - PCR	
SD-9	FY11 Budget History.xls	FY 2011 Budget and Historical Reference for O&M	WP 12.1 - SHEC				
SD-10	Sq Footage FY2009.xls	Useable Square Footage by Building	WP 4.1 - SqFt				
SD-11	debt accrual by series.xls	Accrual Basis Debt Service	WP 5 - Debt				
SD-12	Bond Repayment working copy.xls	Allocation of Debt to Electric Functions	WP 5 - Debt				
SD-13	CP Outstanding.pdf	Balance of Commercial Paper Outstanding	WP 5.2 - Debt				
SD-14	D-2 FY09.xls	Direct Allocations of G&A to the Production Function	WP 6 - G&A				
SD-15	City supp and transfs.xls	Costs Related to City of Austin Programs	WP 7 - City Services				
SD-16	311 Call Center Revenue.xls	Costs and Contra-Expense Associated with the 311 Call Center	WP 7.1 - City Services				
SD-17	B-9 FY09.xls	Insurance Associated with Non-Electric Property	WP 42 - Advocacy & Insurance				
SD-18	Off System Sales.xls	Detail on Off-System Sales in FY 2009	WP 20 - Off-System	WP 44 - PCR			
SD-19	Outside City Revenue.xls	FY 2009 Revenue from Customers Outside the City of Austin	WP 9 - Franchise				
SD-20	Outside City Revenue FY 2010.pdf	FY 2010 Revenue from Customers Outside the City of Austin	WP 9 - Franchise				
SD-21	Power Factor Revenue.xls	Power Factor Revenue Estimate Based on 90% Requirement	WP 10 - PF				
SD-22	SHEC CT O&M.pdf	Estimate of O&M for New SHEC Combustion Turbines	WP 12.2 - SHEC				
SD-23	FPP Scrubbers.xls	Estimate of Impact of Scrubbers on the O&M at FPP	WP 13 - Scrubber				
SD-24	3 3P. Five Year Capital Additions.xls	CIP Spending by Project for FY 2005 - FY 2009	WP 14 - CIP				
SD-25	E-5 FY09.xls	Other (i.e., Non-Rate) Revenue in FY 2009	WP 15 - Other Rev	WP 39 - T-COS Allocators			
SD-26	FPP Expenses.xls	FPP Historical O&M Expenses	WP 11.1 - STP-FPP O&M				
SD-27	Interest Income FY09&10.xls	Interest Income in FY 2009 and FY 2010	WP 18 - Interest				
SD-28	Non-electric FY 2009.xls	Non-Electric Expenses in FY 2009	WP 19.1 - Non-Electric Exp				
SD-29	FERC 417 by Unit.xls	Detail on FERC 417 in FY 2009	WP 19.1 - Non-Electric Exp				
SD-30	LR09_UNB1050 Adj R6cUT Alloc Factors.xls	Load Research by Customer Class	WP 21 - Demand Alloc				
SD-31	Proof of revenue 051711.xlsx	Proof of Revenue	WP 21 - Demand Alloc	WP 22 - Cust Alloc	WP 27 - Revenue	WP 44.2 - PCR	
SD-32	2011 Loss Study_2011March01.xls	Line Loss Study	WP 23.1 - Line Loss				
SD-33	CP Interest Rates.xls	Historical Interest Rates on AE Commercial Paper	WP 5.2 - Debt				
SD-34	811 Lease Expenses.xls	New Six-Year Lease on Building	WP 25 - Building Lease				
SD-35	FERC 556.xls	Detail on FERC 556 in FY 2009	WP 28 - FERC 556				
SD-36	Nodal Fee email.doc	Current Nodal Implementation Surcharge Rate	WP 28.1 - FERC 556				
SD-37	FERC 556 Descriptions.xls	Account Code Descriptions for FERC 556	WP 28.2 - FERC 556				
SD-38	Reserve Balance FY 2010.pdf	Reserve Fund Balances	WP 29 - Reserves				
SD-39	cashquickforecast.xls	Ending Cash Balance for FY 2011	WP 29 - Reserves				
SD-40	MtrCosts_cft_11302010_HM.xls	Meter Cost Data by Customer Type	WP 30.1 - Meters				
SD-41	2009 Manual Elect Read.xls	Count and Cost of Meter Reads in FY 2009	WP 31 - Meter Read				
SD-42	FY12 CC Cost Alloc.xls	Allocation of Customer Care Cost to Electric Utility	WP 31 - Meter Read	WP 7 - City Services			
SD-43	FY2011 AMI Approved Budget.doc	FY 2011 Budget for L+G AMR Meter Reading Costs	WP 31 - Meter Read				
SD-44	38900 B.xls	FY 2011 Transmission Matrix Cost	WP 32 - Matrix Cost				
SD-45	4H T,D,Sub,Xfrms,Poles,Meters.xls	Distribution System Investments	WP 34 - Dist Alloc				
SD-46	Customer & Information Exp.xls	Selected Business Unit Program Costs in FY 2009	WP 36 - Cust Bus	WP 37 - Cust Alloc G&A			
SD-47	Solar Rebate.xls	Solar Rebate Cost	WP 36 - Cust Bus				
SD-48	Key Accts Personnel Cost.xls	Allocation of Key Accounts to Customer Classes	WP 38 - Key Acct				
SD-49	F FY09.xls	Functionalization Factors from the FY 2009 T-COS	WP 39.1 - T-COS Alloc	WP 39.2 - T-COS Alloc	WP 39.3 - T-COS Alloc	WP 39.4 - T-COS Alloc	
SD-50	Rate Case Expenses.xls	Summary of Expenses Related to the Rate Case	WP 40 - Rate Case				
SD-51	4F. Gen name plate, capacity, fuel type.xls	Decker and SHEC Capacity Summary by Unit	WP 41 - Prod Capacity				
SD-52	D-5 FY09.xls	Legislative Advocacy Expenses	WP 42 - Advocacy & Insurance				
SD-53	E-1 FY09.xls	Amortization of Contribution in Aid to Construction	WP 43 - Amort				
SD-54	FY2011_Ratecasestudy_Final.xls	Production Cost Run (UPLAN)	WP 44 - PCR				
SD-55	Indirect Costs.xls	Indirect Costs by FERC in FY 2009	WP 45 - Indirect				

Source Documents

	File Name	Description	Work Papers Referenced	
SD-56	WP C-1.1.1 FY09.xls	Base Revenue in FY 2009	WP 27 - Revenue	
SD-57	STP Regulatory Asset Deferral.pdf	STP Regulatory Asset Deferral	WP 33 - Regulatory Asset	
SD-58	AE Street Lighting.xls	Wattage, Bulbs and kWh for Street Lights	WP 22 - Cust Alloc	
SD-59	FY09 Rate Case Poles Lights.xls	Security Lighting Pole Count by Wattage	WP 22 - Cust Alloc	
SD-60	Generation by Unit.xls	FY 2009 Generation for Traditional Units	WP 44 - PCR	
SD-61	Meter Equip Costs.xls	Meter Cost Data by Customer Class	WP 30 - Meters	
SD-62	Hourly dispatch.xls	MWh Summary from UPLAN	WP 44 - PCR	
SD-63	BSA 1300 Write off.pdf	Write-Off Holly Inventory	WP 8 - Holly Inventory	
SD-64	Reserves.xls	Non-Nuclear Decommissioning Reserves	WP 29.1 - Reserves	
SD-65	ERCOT FEES.xls	Unit Rates for the ERCOT Fees	WP 28.1 - FERC 556	
SD-66	Holly O&M.xls	Detail for Holly O&M in FY 2009	WP 24.1 - Prod O&M	
SD-67	Payroll Adj - BEFORE Remove GAAP.xls	FY 2009 Labor With GAAP Adjustments	WP 3 - Labor	WP 3.2 - Labor
SD-68	Payroll Adj - AFTER Remove GAAP.xls	FY 2009 Labor Without GAAP Adjustments	WP 3.2 - Labor	
SD-69	FY 2011 Labor.xls	FY 2011 Labor Budget by FERC Code	WP 3.2 - Labor	
SD-70	Rate Case Expenses RCA.pdf	RCA for Rate Case Expenses	WP 40 - Rate Case	
SD-71	Meter Reading FERC Reclass.xls	Meter Reading Expense in FY 2009	WP 31.1 - Meter Read	
SD-72	Holly Adjustment.xls	Plant in Service to be Reclassified as Non-Electric	WP 2.2 - Plant	
SD-73	SHEC OH Costs.xls	Reclassifies SHEC Indirect Expenses	WP 45 - Indirect	
SD-74	Reclassify Prepaid Insurance.doc	Email Regarding Reclassifying Prepaid Insurance	WP 35 - Insurance	
SD-75	Reclassify Prepaid Insurance.xls	Data Regarding Prepaid Insurance	WP 35 - Insurance	
SD-76	GO Series 2003 Allocation.pdf	Identifies the Allocation of GO Series 2003 Debt	WP 5 - Debt	
SD-77	Res TOU Billing Units.xls	Demand and Energy Data for Residential Time of Use (TOU)	TOU	
SD-78	Gen Svc TOU Billing Units.xls	Demand and Energy Data for General Service TOU	TOU	
SD-79	Primary and Trans TOU Billing Units.xls	Demand and Energy Data for Primary and Transmission TOU	TOU	
SD-80	STP Expenses.xls	STP Historical O&M Expenses	WP 11.1 - STP-FPP O&M	

Allocation Factors

Worksheet	Name	Description	Work Paper Reference (if applicable)	
Functional Unbundling				
1	Production	Allocate Elements of the Test Year Revenue Requirement to the Production Function		
2	Transmission	Allocate Elements of the Test Year Revenue Requirement to the Transmission Function		
3	Distribution	Allocate Elements of the Test Year Revenue Requirement to the Distribution Function		
4	Customer	Allocate Elements of the Test Year Revenue Requirement to the Customer Function		
5	Other Revenue	Functionalization of Other Revenue in the Test Year	WP 15 - Other Rev	
6	ADJ Furniture	Office Furniture (FERC 391) Adjusted to Maintain T-COS Allocation to Transmission based on SQFT, but Allocate Remainder on PAYROLL and Account for CC&B Addition in Test Year	WP 2 - Plant	
7	ADJ Trans Equip	Tools and Shop Equip (FERC 394) Adjusted to Maintain T-COS Allocation to Transmission based on PLTXGNL-N, but Allocate Remainder on 392 (Transportation Equipment)	WP 2 - Plant	
8	SQFT	Useable Square Footage	WP 4 - SqFt	
9	PAYROLL	Total Functionalized Test Year Electric Labor Cost	WP 3.1 - Labor	
10	PAYXAG	Total Functionalized Test Year Electric Labor Cost, Excluding Administrative and General Labor	WP 3.1 - Labor	
11	INSUR	Insurance Allocator Developed by AE in T-COS	WP 39 - T-COS Allocators	
12	PLTXGNL-N	Net Electric Plant In Service, Excluding General Plant	WP 2 - Plant	
13	TOMXFP	Total O&M, Excluding Commodity Fuel, Purchased Power and A&G		
14	OMAG	Total O&M, Including A&G but Excluding Commodity Fuel and Purchased Power		
15	GNLPLT-N	Net General Plant In Service	WP 2 - Plant	
16	TTRRXGFT	Total Revenue Requirement, Excluding General Fund Transfer and Franchise Fee		
17	FERC 417	Allocation of Electric Utility Expenses within FERC 417	WP 7 - City Services	WP 19.1 - Non-Electric Exp
18	392	Transportation Equipment Allocation	WP 39 - T-COS Allocators	
19	397	Communication Equipment Allocation	WP 39 - T-COS Allocators	
20	Interest	Functionalization of Interest Income in the Test Year	WP 18 - Interest	
21	PAYXAGT	Total Electric Labor, Excluding Transmission, Administrative and General Labor	WP 3.1 - Labor	
22	CIP-Total	Test Year Electric Capital Improvement Spending (FY 2009 actual, FY 2010 and FY 2011 projected)	WP 14.1 - CIP	
23	ACC P&I	Accrual Debt Service (FY 2011)	WP 5 - Debt	
24	TRAN/DIST	Equal Allocation between Transmission and Distribution Functions		
25	DEPR	Depreciation of Electric Plant In Service	WP 2 - Plant	
26	AMORT CIAC	Amortization of Contributions in Aid of Construction	WP 43 - Amort	
27	Misc Op Rev 4874	Miscellaneous Revenue - Operating	WP 39 - T-COS Allocators	
28	Misc Non-Op Rev 4874	Miscellaneous Revenue - Non-Operating	WP 39 - T-COS Allocators	
29	Misc Non-Op Rev 4952	Rentals Non-Operating	WP 39 - T-COS Allocators	
30	ECCCOM	ECC Communication Equipment	WP 39 - T-COS Allocators	
Production				
1	Regulatory	Direct Assignment to Regulatory Clause		
2	Community Benefit	Direct Assignment to Community Benefit Clause		
3	FERC 513	Sub-functionalization Based on Assignment of FERC 513 Non-Fuel Production O&M to Demand Related Generation Resource Types (Base Load Coal and Intermediate Gas)	WP 24 - Prod O&M	
4	FERC 514	Sub-functionalization Based on Assignment of FERC 514 Non-Fuel Production O&M to Demand Related Generation Resource Types (Base Load Coal and Intermediate Gas)	WP 24 - Prod O&M	
5	556 Non-Recoverable	Sub-functionalization of Non-Recoverable FERC 556 Costs Based on Direct Assignment to Green Choice and Remainder to Demand Related Revenue Requirement	WP 44 - PCR	WP 3 - Labor

Allocation Factors

Worksheet	Name	Description	Work Paper Reference (if applicable)
6	555 Non-Recoverable	Sub-functionalization of Non-Recoverable FERC 555 Costs Based on Direct Assignments to Green Choice and Remainder to Demand Related Wind Costs	WP 44 - PCR
7	Prod RR - Demand	Revenue Requirement Associated with Demand Related Generation	
8	Steam Fuel	Steam Generation Fuel for Base Load and Intermediate Resource Types	WP 44 - PCR
9	Nuclear DA	Direct Assignment to Demand Related Nuclear Generation	
10	Nuclear Fuel	Nuclear Generation Fuel for Base Load Resource Type	WP 44 - PCR
11	T Prod Plant - Depr	Sub-functionalization of Total Depreciation on Production Plant In Service, Including General Plant	
12	Other Fuel	Other Generation Fuel for Intermediate and Peak Resource Types	WP 44 - PCR
13	FERC 500	Sub-functionalization Based on Assignment of FERC 500 Non-Fuel Production O&M to Demand Related Generation Resource Types (Base Load Coal and Intermediate Gas)	WP 24 - Prod O&M
14	FERC 502	Sub-functionalization Based on Assignment of FERC 502 Non-Fuel Production O&M to Demand Related Generation Resource Types (Base Load Coal and Intermediate Gas)	WP 24 - Prod O&M
15	FERC 505	Sub-functionalization Based on Assignment of FERC 505 Non-Fuel Production O&M to Demand Related Generation Resource Types (Base Load Coal and Intermediate Gas)	WP 24 - Prod O&M
16	FERC 506	Sub-functionalization Based on Assignment of FERC 506 Non-Fuel Production O&M to Demand Related Generation Resource Types (Base Load Coal and Intermediate Gas)	WP 24 - Prod O&M
17	FERC 510	Sub-functionalization Based on Assignment of FERC 510 Non-Fuel Production O&M to Demand Related Generation Resource Types (Base Load Coal and Intermediate Gas)	WP 24 - Prod O&M
18	FERC 511	Sub-functionalization Based on Assignment of FERC 511 Non-Fuel Production O&M to Demand Related Generation Resource Types (Base Load Coal and Intermediate Gas)	WP 24 - Prod O&M
19	FERC 512	Sub-functionalization Based on Assignment of FERC 512 Non-Fuel Production O&M to Demand Related Generation Resource Types (Base Load Coal and Intermediate Gas)	WP 24 - Prod O&M
20	Prod RR	Generation Revenue Requirement, Excluding Direct Assignments to Regulatory and Community Benefit Adjustment Clauses and Green Choice	
21	Prod 920	Sub-functionalization of FERC 920 Based on Direct Allocations in WP 6 - G&A and the Remainder Based on Generation Labor, Excluding G&A and Direct Assignments to Regulatory and Community Benefit Adjustment Clauses and Green Choice	WP 6 - G&A
22	Prod 921	Sub-functionalization of FERC 921 Based on Direct Allocations in WP 6 - G&A and the Remainder Based on Generation Labor, Excluding G&A and Direct Assignments to Regulatory and Community Benefit Adjustment Clauses and Green Choice	WP 6 - G&A
23	Prod Labor	Total Production Labor, Excluding General and Administrative (G&A) as well as Direct Assignments to Regulatory and Community Benefit Adjustment Clauses and Green Choice	
24	Prod 923	Sub-functionalization of FERC 923 Based on Direct Allocations in WP 6 - G&A and the Remainder Based on Total Production O&M, Excluding G&A, Fuel and Purchased Power, and DA to Regulatory, Community Benefit and Green Choice	WP 6 - G&A
25	Prod 924	Sub-functionalization of FERC 924 Based on Direct Allocations in WP 6 - G&A and the Remainder Based on Generation Net Plant in Service	WP 6 - G&A
26	Prod 925	Sub-functionalization of FERC 925 Based on Direct Allocations in WP 6 - G&A and the Remainder Based on Generation Labor, Excluding G&A and Direct Assignments to Regulatory and Community Benefit Adjustment Clauses and Green Choice	WP 6 - G&A
27	Prod 926	Sub-functionalization of FERC 926 Based on Direct Allocations in WP 6 - G&A and the Remainder Based on Generation Labor, Excluding G&A and Direct Assignments to Regulatory and Community Benefit Adjustment Clauses and Green Choice	WP 6 - G&A
28	Prod 930	Sub-functionalization of FERC 930 Based on Direct Allocations in WP 6 - G&A and the Remainder Based on Generation Labor, Excluding G&A and Direct Assignments to Regulatory and Community Benefit Adjustment Clauses and Green Choice	WP 6 - G&A

Allocation Factors

Worksheet	Name	Description	Work Paper Reference (if applicable)	
29	Prod 935	Sub-functionalization of FERC 935 Based on Direct Allocations in WP 6 - G&A and the Remainder Based on Generation Net Plant in Service	WP 6 - G&A	
30	555 Recoverable	Sub-functionalization of Recoverable FERC 555 Costs Based on Direct Assignments to Wind, Solar, Landfill Methane and Economy Purchase Power	WP 44 - PCR	
31	556 Recoverable	Sub-functionalization of Recoverable FERC 556 Costs Based on Direct Assignment to Regulatory and Remainder Based on Demand and Energy Related Revenue Requirement	WP 28.1 - FERC 556	WP 44 - PCR
32	Prod Debt Service	Sub-functionalization of Debt Service Based on Detailed Allocation of Each Debt Issue	WP 5.3 - Debt	
33	Steam Plant - G	Sub-functionalization of Gross Steam Plant In Service Based on Detailed Allocation of Each Resource Type	WP 26 - Prod Plant	
34	Steam Plant - AD	Sub-functionalization of Accumulated Depreciation for Steam Plant In Service Based on Detailed Allocation of Each Resource Type	WP 26 - Prod Plant	
35	Steam Plant - Depr	Sub-functionalization of Depreciation on Steam Plant In Service Based on Detailed Allocation of Each Resource Type	WP 26 - Prod Plant	
36	Steam Plant - Net	Sub-functionalization of Net Steam Plant In Service Based on Detailed Allocation of Each Resource Type	WP 26 - Prod Plant	
37	Other Gen Plant - G	Sub-functionalization of Gross Other Generation Plant In Service Based on Detailed Allocation of Each Resource Type	WP 26 - Prod Plant	
38	Other Gen Plant - AD	Sub-functionalization of Accumulated Depreciation for Other Generation Plant In Service Based on Detailed Allocation of Each Resource Type	WP 26 - Prod Plant	
39	Other Gen Plant - Depr	Sub-functionalization of Deprecation on Other Generation Plant In Service Based on Detailed Allocation of Each Resource Type	WP 26 - Prod Plant	
40	Other Gen Plant - Net	Sub-functionalization of Net Other Generation Plant In Service Based on Detailed Allocation of Each Resource Type	WP 26 - Prod Plant	
41	Prod RR - Energy	Revenue Requirement Associated with Energy Related Generation		
42	Prod Plant - Net	Sub-functionalization of Net Production Plant In Service (excluding General Plant) Based on Detailed Allocation of Each Resource Type	WP 26 - Prod Plant	
43	FERC 546	Sub-functionalization Based on Assignment of FERC 546 Non-Fuel Production O&M to Demand Related Generation Resource Types (Intermediate Gas and Peak Gas)	WP 24 - Prod O&M	
44	FERC 548	Sub-functionalization Based on Assignment of FERC 548 Non-Fuel Production O&M to Demand Related Generation Resource Types (Intermediate Gas and Peak Gas)	WP 24 - Prod O&M	
45	FERC 549	Sub-functionalization Based on Assignment of FERC 549 Non-Fuel Production O&M to Demand Related Generation Resource Types (Intermediate Gas and Peak Gas)	WP 24 - Prod O&M	
46	FERC 550	Sub-functionalization Based on Assignment of FERC 550 Non-Fuel Production O&M to Demand Related Generation Resource Types (Intermediate Gas and Peak Gas)	WP 24 - Prod O&M	
47	FERC 551	Sub-functionalization Based on Assignment of FERC 551 Non-Fuel Production O&M to Demand Related Generation Resource Types (Intermediate Gas and Peak Gas)	WP 24 - Prod O&M	
48	FERC 552	Sub-functionalization Based on Assignment of FERC 552 Non-Fuel Production O&M to Demand Related Generation Resource Types (Intermediate Gas and Peak Gas)	WP 24 - Prod O&M	
49	FERC 553	Sub-functionalization Based on Assignment of FERC 553 Non-Fuel Production O&M to Demand Related Generation Resource Types (Intermediate Gas and Peak Gas)	WP 24 - Prod O&M	

Allocation Factors

Worksheet	Name	Description	Work Paper Reference (if applicable)
50	FERC 554	Sub-functionalization Based on Assignment of FERC 554 Non-Fuel Production O&M to Demand Related Generation Resource Types (Intermediate Gas and Peak Gas)	WP 24 - Prod O&M
51	Prod 931	Sub-functionalization of FERC 931 Based on Direct Allocations in WP 6 - G&A and the Remainder Based on Generation Labor, Excluding G&A and Direct Assignments to Regulatory and Community Benefit Adjustment Clauses and Green Choice	WP 6 - G&A
52	Prod O&M EXAGF	Total Production Function O&M, Excluding G&A, Commodity Fuel and Purchased Power, and Direct Assignments to Regulatory, Community Benefit and Green Choice	
53	Base Coal DA	Direct Assignment to Demand Related Base Load Coal Generation	
54	Green Choice DA	Direct Assignment to Green Choice	
55	501 Non-Recoverable	Allocation of FERC 501 Non-Recoverable Based on Steam Generation Fuel Expense	WP 44 - PCR
56	Solar Energy DA	Direct Assignment of Solar to Energy	
57	Wind Energy DA	Direct Assignment of Wind to Energy	
58	Econ PP DA	Direct Assignment of Economy Purchase Power to Energy	
59	Int Gas DA	Direct Assignment to Intermediate Gas	
60	Peak Gas DA	Direct Assignment to Demand Related Peak Gas Associated with RMEC - Generation (2234) and BCHP - Gas Turbine (2227)	WP 19.1 - Non-Electric Exp
61	LF Gas Energy DA	Direct Assignment of Landfill Methane to Energy	
Transmission			
1	Trans by Others	Direct Assignment to Transmission of Electricity by Others (FERC 565)	
2	T Load Dispatch	Direct Assignment to Load Dispatch within the Transmission Function	
3	Trans Labor	Total Labor Expense within the Transmission FERCs	
4	Trans RR	Revenue Requirement Associated with Transmission, Excluding Transmission by Others (FERC 565) and Other Revenue	
5	Trans Infrastructure DA	Direct Assignment to Transmission Infrastructure	
6	Trans O&M EXAG	Total Transmission Function O&M, Excluding A&G	
7	Trans General Plnt - Net	Net General Plant in Service Associated with Transmission Function	
8	Trans Plant - Net	Net Plant in Service Based on Assignment of Transmission Plant to Transmission Infrastructure	
9	T Trans Plant - Depr	Total Depreciation for Transmission Plant In Service, Including General Plant	
Distribution			
1	D Load Dispatch	Direct Assignment to Load Dispatch within the Distribution Function	
2	Primary	Direct Assignment to Primary	
3	Dist General Plnt - Net	Net General Plant in Service Associated with Distribution Function	
4	Transformers	Direct Assignment to Transformers	
5	Meters	Direct Assignment to Meters	
6	Services	Direct Assignment to Services	
7	Dist Lighting	Direct Assignment to City-Owned Lighting (Street and Signal Lighting) within Distribution Function	
8	Secondary	Direct Assignment to Secondary	
9	580 Op Supervision	Sub-functionalization of FERC 580 Based on Allocation of Labor Costs in FERC 581 - FERC 589	
10	590 Maint Supervision	Sub-functionalization of FERC 590 Based on Allocation of Labor Costs in FERC 591 - FERC 598	
11	363 Storage	Sub-functionalization of FERC 363 Based on Allocation of Gross Distribution Plant In Service, Excluding FERC 363	
12	Dist Plant - Net	Net Distribution Plant in Service	
13	Dist Labor	Total Labor Expense within the Distribution FERCs	
14	Dist RR	Revenue Requirement Associated with the Distribution Function	
15	Overhead P&C	Allocation to Primary and Secondary Service Levels Based on Investment Cost Estimate	WP 34 - Dist Alloc
16	Underground	Allocation to Primary and Secondary Service Levels Based on Investment Cost Estimate	WP 34 - Dist Alloc
17	T Dist Plant - Depr	Total Depreciation for Distribution Plant In Service, Including General Plant	

Allocation Factors

Worksheet	Name	Description	Work Paper Reference (if applicable)	
18	Dist O&M EXAG	Total Distribution Function O&M, Excluding A&G		
19	Dist Other Rev	Sub-functionalization of Other Revenue within the Distribution Function Based on Direct Assignments and the Remainder Allocated Based on Net Distribution Plant in Service	WP 15 - Other Rev	
Customer				
1	Cust Accounting	Direct Assignment to Customer Accounting		
2	Cust Service	Direct Assignment to Customer Service		
3	Cust Labor	Total Labor Expense within the Customer FERCs		
4	391 Furniture - N	Net Plant in Service for FERC 391 Based on Assignment of New CC&B Billing System to Customer Accounting and the Remainder Allocated Based on Total Customer Labor within the Customer FERCs	WP 2 - Plant	WP 2.3 - Plant
5	391 Furniture - G	Gross Plant in Service for FERC 391 Based on Assignment of New CC&B Billing System to Customer Accounting and the Remainder Allocated Based on Total Customer Labor within the Customer FERCs	WP 2 - Plant	WP 2.3 - Plant
6	391 Furniture - AD	Accumulated Depreciation for FERC 391 Based on Assignment of New CC&B Billing System to Customer Accounting and the Remainder Allocated Based on Total Customer Labor within the Customer FERCs	WP 2 - Plant	WP 2.3 - Plant
7	Cust O&M EXAG	Total Customer Function O&M, Excluding A&G		
8	Cust General Plnt - Net	Net General Plant within Customer Function		
9	Cust RR	Revenue Requirement Associated with the Customer Function		
10	Cust General Plnt - Depr	Depreciation of General Plant within Customer Function		
11	Cust Acct Supervision	Sub-functionalization of FERC 901 Based on Allocation of Labor Costs in FERC 902 - FERC 905		
12	Meter Reading	Direct Assignment to Meter Reading		
13	391 Furniture - Depr	Depreciation for FERC 391 Based on Assignment of New CC&B Billing System to Customer Accounting and the Remainder Allocated Based on Total Customer Labor within the Customer FERCs	WP 2 - Plant	WP 2.3 - Plant
14	Uncollectible DA	Direct Assignment to Uncollectible (i.e., bad debt)		
15	Key Accounts DA	Direct Assignment to Key Accounts		
16	Cust Serv Supervision	Sub-functionalization of FERC 907 Based on Allocation of Labor Costs in FERC 908 - FERC 916		
17	FERC 902	Allocation of FERC 902 Based on Direct Allocation to Key Accounts and the Remainder Allocated to Meter Reading	WP 36 - Cust Bus	
18	FERC 916	Allocation of FERC 916 Based on Direct Allocation to Key Accounts and the Remainder Allocated to Customer Service	WP 36 - Cust Bus	

Allocation Factors

Worksheet	Name	Description	Work Paper Reference (if applicable)	
	19 FERC 911	Allocation of FERC 911 Based on Direct Allocation to Key Accounts and the Remainder Allocated to Customer Service	WP 36 - Cust Bus	
	20 FERC 912	Allocation of FERC 912 Based on Direct Allocation to Key Accounts and the Remainder Allocated to Customer Service	WP 36 - Cust Bus	
COS				
	1 4CP-ERCOT Peak	Contribution to the ERCOT Coincidental Peak by Customer Class for the Four Months of June through September	WP 21 - Demand Alloc	
	2 12NCP Primary	Sum of Monthly Non-Coincidental Peak by Customer Class for the Year, Excluding the Transmission Service Level	WP 21 - Demand Alloc	
	3 Sum Max Demands	Sum of Maximum Monthly Demands by Customer Class for the Year	WP 21 - Demand Alloc	
	4 Rev Req	Proportion of Total Revenue Requirement by Customer Class Before Adjustments (i.e., Redistribution of City of Austin Street Lighting)		
	5 Rev Req Excl COA Lights	Proportion of Total Revenue Requirement by Customer Class After Adjustments (i.e., with the City of Austin Street Lighting Redistributed)		
	6 kWh Sold	Total kWh Sold by Customer Class	WP 21 - Demand Alloc	
	7 No. Cust Mo.	Total Number of Customer Months by Customer Class	WP 22 - Cust Alloc	
	8 City-Owned Lighting	Allocation of Distribution Costs Associated with City-Owned Lighting Based on Bulb Count	WP 22 - Cust Alloc	
	9 12NCP Secondary	Sum of Monthly Non-Coincidental Peak by Customer Class in the Test Year for the Secondary Service Level Only	WP 21 - Demand Alloc	
	10 SMD Excl Primary & Trans	Sum of Maximum Demands for the Secondary Service Level Only (i.e., Excluding Primary and Transmission)	WP 21 - Demand Alloc	
	11 Sum Max Demands - S	Sum of Maximum Monthly Demands by Customer Class for the Summer Months of June Through September	WP 21 - Demand Alloc	
	12 kWh Sold - S	kWh Sold During the Summer Months of June Through	WP 21 - Demand Alloc	
	13 No. Cust Mo. - S	Number of Customer Months During the Summer Months of June Through September Based on 4/12 of Annual Customer-Months	WP 22 - Cust Alloc	
	14 GC $ Sold	Green Choice Revenue by Customer Class in the Test Year	WP 44.1 - PCR	
	15 COA Street Lights	Direct Assignment to City-Owned Street Lighting		
	16 Key Acct	Allocation of the Cost for Key Accounts Based on An Analysis of the Time Spent by Key Accounts' Staff by Customer Class	WP 38 - Key Acct	
	17 Ave & Excess	Allocation Based on Average Demand Plus Excess Demand by Customer Class	WP 21 - Demand Alloc	
	18 Uncollectible	Allocation of Uncollectible Accounts Based on An Analysis of Historical Uncollectible Accounts and the Rate Increase Identified by the Cost of Service by Customer Class	WP 17 - Uncollectible	
	19 Weighted Cust - Meters	Allocation of the Cost of Meters Based on An Investment Cost Estimate by Customer Class	WP 30 - Meters	
	20 NEFL Net GC	Annual Net Energy for Load, Excluding Green Choice	WP 21 - Demand Alloc	
	21 NEFL Net GC - S	Net Energy for Load for the Summer Months, Excluding Green Choice	WP 21 - Demand Alloc	WP 23 - Line Loss
	22 NEFL Net GC Excl COA	Annual Net Energy for Load, Excluding Green Choice and City of Austin Street Lighting	WP 21 - Demand Alloc	
	23 kWh Sold Net GC	kWh Sold by Customer Class, Excluding Green Choice	WP 21 - Demand Alloc	
	24 kWh Sold Net GC - S	kWh Sold During the Summer Months of June Through September, Excluding Green Choice	WP 21 - Demand Alloc	
	25 City-Owned Bulb-Mo.	City-Owned Lighting Bulb Count Times Twelve Months	WP 22 - Cust Alloc	
	26 City-Owned Bulb-Mo. - S	City-Owned Lighting Bulb Count Times Four Months	WP 22 - Cust Alloc	
	27 No. Cust Mo. - Metered	Customer-Months for Metered Customer Classes	WP 22 - Cust Alloc	

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	FY 2009 Actual Source Reference		FY 2009 Actual		Adjustments As Detailed in Columns N - AW		Test Year	Allocation Source Reference	Allocation Basis
A		B	C		D		E		F	G	H
1	**Power Production Expenses**										
2	Steam Power Generation										
3	**Operation**										
4	Operation Supervision and Engineering	500	WP 1	$	8,461,250	$	(549,563)	$	7,911,687		Production
5	Fuel - Recoverable	501	WP 16		299,909,760		(168,380,271)		131,529,489		Production
6	Fuel - Non-Recoverable	501	WP 16		4,083,544		861,398		4,944,942		Production
7	Steam Expenses	502	WP 1		4,100,525		2,246,471		6,346,996		Production
8	Steam from other Sources	503	WP 1		-		-		-		Production
9	Steam Transferred	504	WP 1		-		-		-		Production
10	Electric Expenses	505	WP 1		5,013,588		(3,312,638)		1,700,950		Production
11	Miscellaneous Steam Expenses	506	WP 1		4,394,541		(195,307)		4,199,234		Production
12	Rents	507	WP 1		146		(146)		-		Production
13				$	325,963,353	$	(169,330,055)	$	156,633,297		
14											
15	**Maintenance**										
16	Maintenance Supervision	510	WP 1	$	2,273,086	$	183,652	$	2,456,738		Production
17	Maintenance of Structures	511	WP 1		215,751		11,503		227,254		Production
18	Maintenance of Boiler Plant	512	WP 1		6,356,222		(557,654)		5,798,568		Production
19	Maintenance of Electric Plant	513	WP 1		3,534,272		(511,592)		3,022,679		Production
20	Maintenance of Miscellaneous Steam Plant	514	WP 1		3,553,188		102,529		3,655,717		Production
21	Rents	515	WP 1		-		-		-		Production
22				$	15,932,519	$	(771,562)	$	15,160,958		
23											
24	Nuclear Power Generation										
25	**Operation**										
26	Operation Supervision	517	WP 1	$	9,211,756	$	(284,366)	$	8,927,390		Production
27	Nuclear Fuel Expense	518	WP 16		16,866,183		2,480,877		19,347,060		Production
28	Coolants and Water	519	WP 1		953,232		83,777		1,037,009		Production
29	Steam Expenses	520	WP 1		1,458,922		501,905		1,960,827		Production
30	Electric Expenses	523	WP 1		4,134,216		191,435		4,325,651		Production
31	Misc Nuclear Power Expenses	524	WP 1		12,914,335		189,331		13,103,665		Production
32	Rents	525	WP 1		-		-		-		Production
33				$	45,538,644	$	3,162,959	$	48,701,602		
34											
35	**Maintenance**										
36	Maintenance Supervision	528	WP 1	$	4,898,622	$	1,152,420	$	6,051,042		Production
37	Maintenance of Structures	529	WP 1		2,347,069		341,657		2,688,726		Production
38	Maintenance of Reactor Plant	530	WP 1		5,620,149		1,524,030		7,144,179		Production
39	Maintenance of Electric Plant	531	WP 1		2,852,587		713,296		3,565,883		Production
40	Maintenance of Miscellaneous	532	WP 1		662,509		86,131		748,640		Production
41				$	16,380,935	$	3,817,533	$	20,198,469		
42											
43	Hydraulic Power Generation										
44	**Maintenance**										
45	Maintenance Supervision	541	WP 1	$	-	$	-	$	-		Production
46	Maintenance of Structures	542	WP 1		-		-		-		Production
47	Maintenance of Reservoirs, Dams & Waterways	543	WP 1		-		-		-		Production
48	Maintenance of Electric Plant	544	WP 1		-		-		-		Production
49	Maintenance of Miscellaneous Hydraulic Plant	545	WP 1		-		-		-		Production
50				$	-	$	-	$	-		
51											

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	FY 2009 Actual Source Reference	FY 2009 Actual	Adjustments As Detailed in Columns N - AW	Test Year	Allocation Source Reference	Allocation Basis
A		B	C	D	E	F	G	H
52	Other Power Generation							
53	**Operation**							
54	Operation Supervision	546	WP 1	$ 2,356,493	$ 144,086	$ 2,500,579		Production
55	Fuel	547	WP 16	4,206	122,424,961	122,429,167		Production
56	Generation Expenses	548	WP 1	2,489,508	1,567,881	4,057,389		Production
57	Miscellaneous Other Power Generation Expenses	549	WP 1	130,467	203,125	333,592		Production
58	Rents	550	WP 1	205,134	72	205,206		Production
59	Energy Efficiency			-	21,485,378	21,485,378		Production
60	Green Building			-	1,881,981	1,881,981		Production
61	Solar Rebate			-	4,352,770	4,352,770		Production
62				$ 5,185,807	$ 152,060,254	$ 157,246,061		
63								
64	**Maintenance**							
65	Maintenance Supervision and Engineering	551	WP 1	$ 22,617	$ 20,596	$ 43,213		Production
66	Maintenance of Structures	552	WP 1	105,620	41,958	147,578		Production
67	Maintenance of Generating and Electric Equipment	553	WP 1	8,172,762	5,080,363	13,253,125		Production
68	Maintenance of Misc Other Power Generation Plant	554	WP 1	1,169,131	274,779	1,443,910		Production
69				$ 9,470,131	$ 5,417,695	$ 14,887,826		
70								
71	Other Power Supply							
72	Purchased Power - Recoverable	555	WP 16	$ 78,830,176	$ 17,681,726	$ 96,511,902		Production
73	Purchased Power - Non-Recoverable	555	WP 16	26,856,820	(16,453,605)	10,403,215		Production
74	System Control and Load Dispatching - Recoverable	556	WP 16	12,791,041	8,288,917	21,079,958		Production
75	System Control and Load Dispatching - Non-Recoverable	556	WP 16	9,921,783	(8,118,813)	1,802,970		Production
76	Other Power Expenses	557	WP 1	461,942	27,851	489,793		Production
77				$ 128,861,761	$ 1,426,076	$ 130,287,838		
78								
79	**Total Power Production Expense**			**$ 547,333,150**	**$ (4,217,099)**	**$ 543,116,051**		
80								
81	**Transmission Expense**							
82	**Operation**							
83	Operations Supervision and Engineering	560	WP 1	$ 4,139,800	$ 993,366	$ 5,133,166		Transmission
84	Load Dispatching	561	WP 1	1,581,229	51,394	1,632,624		Transmission
85	Station Expenses	562	WP 1	181,382	204,001	385,383		Transmission
86	Overhead Line Expenses	563	WP 1	291,702	867,736	1,159,438		Transmission
87	Underground Line Expenses	564	WP 1	(189)	189	-		Transmission
88	Transmission of Electricity by Others	565	WP 1	58,477,601	7,437,651	65,915,251		Transmission
89	Miscellaneous Transmission Expenses	566	WP 1	589,653	16,525	606,178		Transmission
90	Rents	567	WP 1	3,000	-	3,000		Transmission
91				$ 65,264,177	$ 9,570,863	$ 74,835,040		
92								
93	**Maintenance**							
94	Maintenance Supervision and Engineering	568	WP 1	$ 343,997	$ 740	$ 344,737		Transmission
95	Maintenance of Structures	569	WP 1	22,031	8,204	30,235		Transmission
96	Maintenance of Station Equipment	570	WP 1	(57,698)	1,310,874	1,253,176		Transmission
97	Maintenance of Overhead Lines	571	WP 1	1,286,533	18,788	1,305,322		Transmission
98	Maintenance of Underground Lines	572	WP 1	36,353	-	36,353		Transmission
99	Maintenance of Miscellaneous Transmission Plant	573	WP 1	17,866	(3,406)	14,460		Transmission
100				$ 1,649,083	$ 1,335,200	$ 2,984,283		
101								

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	FY 2009 Actual Source Reference	FY 2009 Actual	Adjustments As Detailed in Columns N - AW	Test Year	Allocation Source Reference	Allocation Basis
A		B	C	D	E	F	G	H
102	**Total Transmission Expenses**			**$ 66,913,260**	**$ 10,906,062**	**$ 77,819,322**		
103								
104	**Distribution Expenses**							
105	**Operation**							
106	Operations Supervision and Engineering	580	WP 1	$ 8,214,447	$ (368,022)	$ 7,846,426		Distribution
107	Load Dispatching	581	WP 1	2,167,575	(6,429)	2,161,146		Distribution
108	Station Expenses	582	WP 1	1,189,288	25,751	1,215,039		Distribution
109	Overhead Line Expenses	583	WP 1	2,985,415	5,162,113	8,147,529		Distribution
110	Underground Line Expenses	584	WP 1	(674,154)	3,802,454	3,128,300		Distribution
111	Street Lighting	585	WP 1	104,565	284,590	389,156		Distribution
112	Meter Expenses	586	WP 1	3,931,002	(667,185)	3,263,817		Distribution
113	Customer Installation Expenses	587	WP 1	135,513	-	135,513		Distribution
114	Miscellaneous Distribution Expenses	588	WP 1	3,176,834	864,771	4,041,605		Distribution
115	Rents	589	WP 1	(507)	1,134	627		Distribution
116				$ 21,229,979	$ 9,099,177	$ 30,329,157		
117								
118	**Maintenance**							
119	Maintenance Supervision and Engineering	590	WP 1	$ 137,125	$ 10,150	$ 147,276		Distribution
120	Maintenance of Structures	591	WP 1	104,947	-	104,947		Distribution
121	Maintenance of Station Equipment	592	WP 1	2,551,043	372,256	2,923,299		Distribution
122	Maintenance of Overhead Lines	593	WP 1	12,378,588	113,345	12,491,933		Distribution
123	Maintenance of Underground Lines	594	WP 1	157,935	41,985	199,921		Distribution
124	Maintenance of Line Transformers	595	WP 1	6,916	1,571	8,487		Distribution
125	Maintenance of Street Lighting and Signal Systems	596	WP 1	1,382,155	119,181	1,501,335		Distribution
126	Maintenance of Meters	597	WP 1	68,127	11,868	79,995		Distribution
127	Maintenance of Miscellaneous Distribution Plant	598	WP 1	1,141,171	114,999	1,256,171		Distribution
128				$ 17,928,007	$ 785,355	$ 18,713,363		
129								
130	**Total Distribution Expenses**			**$ 39,157,987**	**$ 9,884,532**	**$ 49,042,519**		
131								
132	**Customer and Information Expenses**							
133								
134	Customer Accounts Expenses							
135	Supervision	901	WP 1	$ 201,021	$ (91,590)	$ 109,431		Customer
136	Meter Reading Expenses	902	WP 1	11,108,833	3,182,273	14,291,107		Customer
137	Customer Records and Collection Expenses	903	WP 1	27,215,210	532,564	27,747,774		Customer
138	Uncollectible Accounts	904	WP 1	3,649,195	1,020,593	4,669,787		Customer
139	Miscellaneous Customer Accounts Expenses	905	WP 1	(15,251,452)	(1,076,085)	(16,327,537)		Customer
140				$ 26,922,807	$ 3,567,755	$ 30,490,562		
141								
142	Cust. Service & Information Expense							
143	Supervision	907	WP 1	$ 3,237,337	$ (3,063,051)	$ 174,286		Customer
144	Customer Assistance Expenses	908	WP 1	22,959,873	(22,719,227)	240,646		Customer
145	Informational & Instructional Advertising Expenses	909	WP 1	1,022,743	(934,167)	88,576		Customer
146	Misc Customer Service & Informational Expenses	910	WP 1	750,929	(409,512)	341,418		Customer
147	Supervision	911	WP 1	8,324,843	1,815,709	10,140,552		Customer
148	Demonstrating & Selling Expense	912	WP 1	3,222,289	141,458	3,363,747		Customer
149	Advertising Expense	913	WP 1	448,021	41,513	489,534		Customer
150	Miscellaneous Sales Expense	916	WP 1	452,925	(126,236)	326,690		Customer
151				$ 40,418,960	$ (25,253,512)	$ 15,165,448		

Functional Unbundling
Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	FY 2009 Actual Source Reference	FY 2009 Actual	Adjustments As Detailed in Columns N - AW	Test Year	Allocation Source Reference	Allocation Basis
A		B	C	D	E	F	G	H
152								
153	**Total Customer and Information Expenses**			**$ 67,341,767**	**$ (21,685,757)**	**$ 45,656,010**		
154								
155	**General and Administrative Expenses**							
156	Administrative and General Salaries	920	WP 1	$ 38,780,376	$ (7,889,227)	$ 30,891,148	WP 6	based on WP-6
157	Office Supplies and Expenses	921	WP 1	28,007,506	(7,511,597)	20,495,909	WP 6	based on WP-6
158	Administrative Expense Transferred	922	WP 1	(287,411)	1,251,992	964,581	WP 6	based on WP-6
159	Outside Services Employed	923	WP 1	10,565,986	(590,886)	9,975,100	WP 6	based on WP-6
160	Property Insurance	924	WP 1	683,345	2,209,713	2,893,058	WP 6	based on WP-6
161	Injuries and Damages	925	WP 1	4,073,967	(1,110,247)	2,963,720	WP 6	based on WP-6
162	Employee Pension and Benefits	926	WP 1	29,056,796	(18,675,215)	10,381,582	WP 6	based on WP-6
163	Regulatory Commission Expense	928	WP 1	-	1,292,907	1,292,907	WP 6	based on WP-6
164	General Expenses	930	WP 1	22,428,040	(957,173)	21,470,867	WP 6	based on WP-6
165	Rents	931	WP 1	1,607,142	517,778	2,124,920	WP 6	based on WP-6
166	Maintenance of General Plant	935	WP 1	879,615	67,403	947,017	WP 6	based on WP-6
167				$ 135,795,362	$ (31,394,553)	$ 104,400,808		
168								
169	**Total Operations & Maintenance Expenses**			**$ 856,541,526**	**$ (36,506,815)**	**$ 820,034,711**		
170								
171	**Depreciation & Amortization of CIAC**							
172	Depreciation Expense	403	WP 1	$ 114,171,721	$ 8,223,622	$ 122,395,343	WP 2	DEPR
173	Amortization of CIAC		WP 43	(5,180,831)	-	(5,180,831)	WP 43	AMORT CIAC
174				**$ 108,990,890**	**$ 8,223,622**	**$ 117,214,512**		
175								
176	**Debt Service**		WP 5	**$ 176,919,813**	**$ (8,849,523)**	**$ 168,070,290**	WP 5	ACC P&I
177								
178	**General Fund Transfer**	421.5	WP 1	**$ 95,000,000**	**$ 8,000,000**	**$ 103,000,000**	Functional Unbundling	TTRRXGFT
179								
180	**Margin (as defined below)**			**$ 26,277,668**	**$ (17,320,250)**	**$ 8,957,418**		
181								
182	**Sub-Total Revenue Requirement**			**$ 1,263,729,897**	**$ (46,452,965)**	**$ 1,217,276,931**		
183								
184	**Other Expenses**							
185	Misc Service Revenue	451	WP 1	$ 22,056	$ 7,353	$ 29,409		Production
186	Donations	426	WP 1	38,342	3,011	41,353		Production
187	Taxes Other Than Income	408	WP 1	9,117	17,405	26,522	Functional Unbundling	TTRRXGFT
188	Expenses - Non-utility operations	417	WP 1	16,288,944	(13,957,256)	2,331,688	WP 7	FERC 417
189	Franchise Fees			-	1,123,778	1,123,778	Functional Unbundling	Distribution
190				**$ 16,358,459**	**$ (12,805,709)**	**$ 3,552,750**		
191								
192	**Other (Non-Rate) Revenue**							
193	Miscellaneous Nonoperating Income	421	WP 1	$ 5,177	$ -	$ 5,177	WP 2	PLTXGNL-N
194	Other Revenue		WP 15	106,808,816	(22,005,115)	84,803,701	WP 15	Other Revenue
195	Off-System Sales		SD-31	16,877,957	(16,877,957)	-		Production
196				**$ 123,691,950**	**$ (38,883,072)**	**$ 84,808,878**		
197								
198	**Total Revenue Requirement**			**$ 1,156,396,406**	**$ (20,375,603)**	**$ 1,136,020,803**		
199								
200	**System Retail Sales (MWh)**		SD-31	**12,076,915**	**(262,976)**	**11,813,939**		
201	Average Rate ($/MWh)			$ 95.75		$ 96.16		

Functional Unbundling
Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	FY 2009 Actual Source Reference	FY 2009 Actual	Adjustments As Detailed in Columns N - AW	Test Year	Allocation Source Reference	Allocation Basis
A		B	C	D	E	F	G	H
202								
203	**Comparison to Rate Revenue - FY 2009 Rate Structure**							
204	Base Revenue		WP 27	$ 614,797,276	$ (10,540,448)	$ 604,256,828		
205	Recoverable Fuel		SD-8	408,401,366	(17,503,790)	390,897,575		
206	Green Choice		SD-8	31,683,294	(21,626,212)	10,057,082		
207	Remove Service Area Street Lighting Fuel Cost			-	(1,077,588)	(1,077,588)		
208				**$ 1,054,881,935**	**$ (50,748,038)**	**$ 1,004,133,897**		
209								
210								
211	**Over / (Under) Recovery**			**$ (101,514,471)**	**$ (30,372,435)**	**$ (131,886,905)**		
212								
213	*Required Increase / (Decrease) in Rate Revenue*			*9.6%*		*13.1%*		
214								
215								
216	**Recoverable Fuel Cost**							
217	Fuel	501	Line 5	$ 299,909,760	$ (168,380,271)	$ 131,529,489		
218	Nuclear Fuel Expense	518	Line 27	16,866,183	2,480,877	19,347,060		
219	Fuel	547	Line 55	4,206	122,424,961	122,429,167		
220	Purchased Power	555	Line 72	78,830,176	17,681,726	96,511,902		
221	System Control and Load Dispatching	556	Line 74	12,791,041	8,288,917	21,079,958		
222				$ 408,401,366	$ (17,503,790)	$ 390,897,575		
223								
224	**Off-System Sales**		WP 20	$ 21,657,426	$ (21,657,426)	$ -		
225								
226	**Net Cost to AE**			**$ 386,743,940**	**$ 4,153,635**	**$ 390,897,575**		
227								
228								
229	**Margin Calculation**							
230	**Cash Sources**							
231	Depreciation Expense	403	WP 1	$ 114,171,721	$ 8,223,622	$ 122,395,343	WP 2	DEPR
232	Amortization of CIAC		WP 43	(5,180,831)	-	(5,180,831)	WP 43	AMORT CIAC
233	Interest and Dividend Income	419	WP 1	17,401,562	(9,804,953)	7,596,609	WP 18	Interest
234				$ 126,392,452	$ (1,581,332)	$ 124,811,121		
235								
236	**Cash Uses**							
237	Capital From Current Revenue		WP 14	$ 152,670,120	$ (41,579,109)	$ 111,091,011	WP 14	CIP-Total
238	Required Contributions to Decommissioning Reserves			-	6,716,995	6,716,995		Production
239	Required Contributions to Reserves			-	15,960,533	15,960,533	WP 2	DEPR
240				$ 152,670,120	$ (18,901,581)	$ 133,768,539		
241								
242	**Required Margin**			**$ 26,277,668**	**$ (17,320,250)**	**$ 8,957,418**		
243								
244								
245	**Debt Service Coverage Ratio (DSCR)**							
246	Rate Revenue (assuming required rate increase in Test Year)			$ 1,054,881,935	$ 81,138,867	$ 1,136,020,803		
247	Other Operating & Non-Operating Revenue			123,691,950	(38,883,072)	84,808,878		
248				$ 1,178,573,885	$ 42,255,796	$ 1,220,829,681		
249								
250	Operations & Maintenance			$ 856,541,526	$ (36,506,815)	$ 820,034,711		
251	Other Expenses			16,358,459	(12,805,709)	3,552,750		

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	FY 2009 Actual Source Reference	FY 2009 Actual	Adjustments As Detailed in Columns N - AW	Test Year	Allocation Source Reference	Allocation Basis
A		B	C	D	E	F	G	H
252	Non-Revenue Bonds at 1.0x DSCR			337,085	19,748	356,833		
253				$ 873,237,069	$ (49,292,776)	$ 823,944,294		
254								
255	**Balance Available for Revenue Debt Service**			**$ 305,336,816**	**$ 91,548,572**	**$ 396,885,388**		
256								
257	Revenue Debt Service			$ 176,582,728	$ (8,869,271)	$ 167,713,457		
258								
259	Revenue Debt Coverage Ratio			**1.73**	**0.64**	**2.37**		
260								
261	**Additional Funds Required to Meet 2.0 DSCR Financial Policy**			**$ 47,828,640**	**$ (47,828,640)**	**$ -**		
262								
263								
264	**Required Reserve Fund Balance**		WP 29	**$ 442,237,000**	**$ (141,515,026)**	**$ 300,721,974**		
265	(excludes restricted reserves for decommissioning and debt as well as deposits)							
266								
267	**Working Capital Reserve Fund**			$ 51,343,997	$ 323,407	$ 51,667,404		
268	*Target: 45 days of O&M less fuel and purchased power*		WP 29	*$ 51,343,997*	*$ 323,407*	*$ 51,667,404*		
269								
270	Subtotal Reserves Funds after Working Capital Reserve Fund			$ 390,893,003	$ (141,838,433)	$ 249,054,570		
271								
272	**Strategic Reserve Fund**							
273	Contingency Reserve Fund			$ 68,458,663	$ 431,209	$ 68,889,872		
274	*Target: 60 days of O&M less fuel and purchased power*		WP 29	*$ 68,458,663*	*$ 431,209*	*$ 68,889,872*		
275	Emergency Reserve Fund			$ 68,458,663	$ 431,209	$ 68,889,872		
276	*Target: 60 days of O&M less fuel and purchased power*		WP 29	*$ 68,458,663*	*$ 431,209*	*$ 68,889,872*		
277	Rate Stabilization Fund			$ 109,030,479	$ (11,071,725)	$ 97,958,754		
278	*Target: 90 days of Power Cost (Net of ERCOT Fees)*		WP 29	*$ 109,030,479*	*$ (11,071,725)*	*$ 97,958,754*		
279	Subtotal Strategic Reserve Fund			$ 245,947,805	$ (10,209,307)	$ 235,738,498		
280								
281	Subtotal Reserves Funds after Strategic Reserve Fund			$ 144,945,198	$ (131,629,125)	$ 13,316,072		
282								
283	**Repair and Replacement Fund**			$ 57,085,861	$ (43,769,788)	$ 13,316,072		
284	*Target: 1/2 of annual depreciation*		WP 29	*$ 57,085,861*	*$ 4,111,811*	*$ 61,197,672*		
285								
286	Subtotal Reserves Funds after Repair and Replacement Fund			$ 87,859,337	$ (87,859,337)	$ -		
287								
288	Total Reserves			$ 442,237,000	$ (141,515,026)	$ 300,721,974		
289	Total Reserve Requirements			$ 354,377,663	$ (5,774,090)	$ 348,603,573		
290	Undesignated/Unrestricted Reserve			$ 87,859,337	$ (87,859,337)			
291	Reserve Deficiency				$ 47,881,599	$ 47,881,599		
292								
293								
294								
295	**Allocation Factors**							
296	1 Production							
297								
298	2 Transmission							
299								
300	3 Distribution							
301								

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.			FERC Account	FY 2009 Actual Source Reference	FY 2009 Actual	Adjustments As Detailed in Columns N - AW	Test Year	Allocation Source Reference	Allocation Basis
A			B	C	D	E	F	G	H
302	4	Customer							
303									
304	5	Other Revenue	WP 15 - Other Rev						
305									
306									
307	6	ADJ Furniture	WP 2 - Plant						
308		Office Furniture (FERC 391): Maintain T-COS Allocation to Trans on SQFT, Allocate Remainder on PAYROLL, New CC&B to Cust					106,713,463		
309		T-COS Allocation of FERC 391 based on SQFT					71,900,419		SQFT
310		Undo Allocation of Non-Transmission Related FERC 391 on SQFT					(64,233,872)		
311		CC&B Direct to Customer					34,813,044		Customer
312		Remainder Allocated Based on PAYROLL					64,233,872		PAYROLL
313		Redistribute Portion Allocated to Transmission Based on PAYROLL					-		
314									
315	7	ADJ Trans Equip	WP 2 - Plant						
316		Tools and Shop Equip (FERC 394): Maintain T-COS Allocation to Trans on PLTXGNL-N, Allocate Remainder Based on 392					3,658,641		
317		T-COS Allocation of FERC 394 based on PLTXGNL-N					3,658,641		PLTXGNL-N
318		Undo Allocation of Non-Transmission Related FERC 394 on PLTXGNL-N					(3,210,238)		
319		Remainder Allocated Based on 392 (Transportation Equipment)					3,210,238		392
320		Redistribute Portion Allocated to Transmission Based on 392 (Transportation Equipment)					0		
321									
322	8	SQFT	WP 4 - SqFt						
323		Useable Square Footage							
324									
325	9	PAYROLL	WP 3.1 - Labor						
326		Total Electric Labor							
327									
328	10	PAYXAG	WP 3.1 - Labor						
329		Total Electric Labor, Excluding Administrative and General Labor							
330									
331	11	INSUR	WP 39 - T-COS Allocators						
332		Insurance Allocator Developed by AE in T-COS							
333									
334	12	PLTXGNL-N	WP 2 - Plant						
335		Net Electric Plant In Service, Excluding General Plant							
336									
337	13	TOMXFP							
338		Total O&M, Excluding Commodity Fuel, Purchased Power and A&G							
339									
340	14	OMAG							
341		Total O&M, Including A&G but Excluding Commodity Fuel and Purchased Power							
342									
343	15	GNLPLT-N	WP 2 - Plant						
344		Net General Plant In Service							
345									
346	16	TTRRXGFT							
347		Total Revenue Requirement, Excluding General Fund Transfer and Franchise Fee							
348									
349	17	FERC 417	WP 7 - City Services & WP 19.1 - Non-Electric Exp						
350		Allocation of Electric Utility Expenses within FERC 417					2,331,688		
351		311 Call Center - Net Cost Attributable to AE					2,079,086		Customer
352		RMEC-Generation (Unit 2234)					251,657		Production

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.			FERC Account	FY 2009 Actual Source Reference	FY 2009 Actual	Adjustments As Detailed in Columns N - AW	Test Year	Allocation Source Reference	Allocation Basis
A			B	C	D	E	F	G	H
353		Bchp-Gas Turbine (Unit 2227)					945		Production
354									
355	18	392	WP 39 - T-COS Allocators						
356		Transportation Equipment Allocation							
357									
358	19	397	WP 39 - T-COS Allocators						
359		Communication Equipment Allocation							
360									
361	20	Interest	WP 18 - Interest						
362		Functionalization of Interest Income in the Test Year							
363									
364	21	PAYXAGT	WP 3.1 - Labor						
365		Total Electric Labor, Excluding Transmission, Administrative and General Labor							
366									
367	22	CIP-Total	WP 14.1 - CIP						
368		Average Capital Improvement Spending (FY 2009 actual, FY 2010 and FY 2011 projected)							
369									
370	23	ACC P&I	WP 5 - Debt						
371		Accrual Debt Service (FY 2011)							
372									
373	24	TRAN/DIST							
374									
375									
376	25	DEPR	WP 2 - Plant						
377		Depreciation of Electric Plant In Service							
378									
379	26	AMORT CIAC	WP 43 - Amort						
380		Amortization of Contributions in Aid of Construction							
381									
382	27	Misc Op Rev 4874	WP 39 - T-COS Allocators						
383									
384									
385	28	Misc Non-Op Rev 4874	WP 39 - T-COS Allocators						
386									
387									
388	29	Misc Non-Op Rev 4952	WP 39 - T-COS Allocators						
389									
390									
391	30	ECCCOM	WP 39 - T-COS Allocators						
392		ECC Communication Equipment							

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Production	Transmission	Distribution	Customer	Total
A		B	I	J	K	L	M
1	**Power Production Expenses**						
2	Steam Power Generation						
3	**Operation**						
4	Operation Supervision and Engineering	500	$ 7,911,687	$ -	$ -	$ -	$ 7,911,687
5	Fuel - Recoverable	501	131,529,489	-	-	-	131,529,489
6	Fuel - Non-Recoverable	501	4,944,942	-	-	-	4,944,942
7	Steam Expenses	502	6,346,996	-	-	-	6,346,996
8	Steam from other Sources	503	-	-	-	-	-
9	Steam Transferred	504	-	-	-	-	-
10	Electric Expenses	505	1,700,950	-	-	-	1,700,950
11	Miscellaneous Steam Expenses	506	4,199,234	-	-	-	4,199,234
12	Rents	507	-	-	-	-	-
13			$ 156,633,297	$ -	$ -	$ -	$ 156,633,297
14							
15	**Maintenance**						
16	Maintenance Supervision	510	$ 2,456,738	$ -	$ -	$ -	$ 2,456,738
17	Maintenance of Structures	511	227,254	-	-	-	227,254
18	Maintenance of Boiler Plant	512	5,798,568	-	-	-	5,798,568
19	Maintenance of Electric Plant	513	3,022,679	-	-	-	3,022,679
20	Maintenance of Miscellaneous Steam Plant	514	3,655,717	-	-	-	3,655,717
21	Rents	515	-	-	-	-	-
22			$ 15,160,958	$ -	$ -	$ -	$ 15,160,958
23							
24	Nuclear Power Generation						
25	**Operation**						
26	Operation Supervision	517	$ 8,927,390	$ -	$ -	$ -	$ 8,927,390
27	Nuclear Fuel Expense	518	19,347,060	-	-	-	19,347,060
28	Coolants and Water	519	1,037,009	-	-	-	1,037,009
29	Steam Expenses	520	1,960,827	-	-	-	1,960,827
30	Electric Expenses	523	4,325,651	-	-	-	4,325,651
31	Misc Nuclear Power Expenses	524	13,103,665	-	-	-	13,103,665
32	Rents	525	-	-	-	-	-
33			$ 48,701,602	$ -	$ -	$ -	$ 48,701,602
34							
35	**Maintenance**						
36	Maintenance Supervision	528	$ 6,051,042	$ -	$ -	$ -	$ 6,051,042
37	Maintenance of Structures	529	2,688,726	-	-	-	2,688,726
38	Maintenance of Reactor Plant	530	7,144,179	-	-	-	7,144,179
39	Maintenance of Electric Plant	531	3,565,883	-	-	-	3,565,883
40	Maintenance of Miscellaneous	532	748,640	-	-	-	748,640
41			$ 20,198,469	$ -	$ -	$ -	$ 20,198,469
42							
43	Hydraulic Power Generation						
44	**Maintenance**						
45	Maintenance Supervision	541	$ -	$ -	$ -	$ -	$ -
46	Maintenance of Structures	542	-	-	-	-	-
47	Maintenance of Reservoirs, Dams & Waterways	543	-	-	-	-	-
48	Maintenance of Electric Plant	544	-	-	-	-	-
49	Maintenance of Miscellaneous Hydraulic Plant	545	-	-	-	-	-
50			$ -	$ -	$ -	$ -	$ -
51							

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Production	Transmission	Distribution	Customer	Total
A		B	I	J	K	L	M
52	Other Power Generation						
53	**Operation**						
54	Operation Supervision	546	$ 2,500,579	$ -	$ -	$ -	$ 2,500,579
55	Fuel	547	122,429,167	-	-	-	122,429,167
56	Generation Expenses	548	4,057,389	-	-	-	4,057,389
57	Miscellaneous Other Power Generation Expenses	549	333,592	-	-	-	333,592
58	Rents	550	205,206	-	-	-	205,206
59	Energy Efficiency		21,485,378	-	-	-	21,485,378
60	Green Building		1,881,981	-	-	-	1,881,981
61	Solar Rebate		4,352,770	-	-	-	4,352,770
62			$ 157,246,061	$ -	$ -	$ -	$ 157,246,061
63							
64	**Maintenance**						
65	Maintenance Supervision and Engineering	551	$ 43,213	$ -	$ -	$ -	$ 43,213
66	Maintenance of Structures	552	147,578	-	-	-	147,578
67	Maintenance of Generating and Electric Equipment	553	13,253,125	-	-	-	13,253,125
68	Maintenance of Misc Other Power Generation Plant	554	1,443,910	-	-	-	1,443,910
69			$ 14,887,826	$ -	$ -	$ -	$ 14,887,826
70							
71	Other Power Supply						
72	Purchased Power - Recoverable	555	$ 96,511,902	$ -	$ -	$ -	$ 96,511,902
73	Purchased Power - Non-Recoverable	555	10,403,215	-	-	-	10,403,215
74	System Control and Load Dispatching - Recoverable	556	21,079,958	-	-	-	21,079,958
75	System Control and Load Dispatching - Non-Recoverable	556	1,802,970	-	-	-	1,802,970
76	Other Power Expenses	557	489,793	-	-	-	489,793
77			$ 130,287,838	$ -	$ -	$ -	$ 130,287,838
78							
79	**Total Power Production Expense**		**$ 543,116,051**	**$ -**	**$ -**	**$ -**	**$ 543,116,051**
80							
81	**Transmission Expense**						
82	**Operation**						
83	Operations Supervision and Engineering	560	$ -	$ 5,133,166	$ -	$ -	$ 5,133,166
84	Load Dispatching	561	-	1,632,624	-	-	1,632,624
85	Station Expenses	562	-	385,383	-	-	385,383
86	Overhead Line Expenses	563	-	1,159,438	-	-	1,159,438
87	Underground Line Expenses	564	-	-	-	-	-
88	Transmission of Electricity by Others	565	-	65,915,251	-	-	65,915,251
89	Miscellaneous Transmission Expenses	566	-	606,178	-	-	606,178
90	Rents	567	-	3,000	-	-	3,000
91			$ -	$ 74,835,040	$ -	$ -	$ 74,835,040
92							
93	**Maintenance**						
94	Maintenance Supervision and Engineering	568	$ -	$ 344,737	$ -	$ -	$ 344,737
95	Maintenance of Structures	569	-	30,235	-	-	30,235
96	Maintenance of Station Equipment	570	-	1,253,176	-	-	1,253,176
97	Maintenance of Overhead Lines	571	-	1,305,322	-	-	1,305,322
98	Maintenance of Underground Lines	572	-	36,353	-	-	36,353
99	Maintenance of Miscellaneous Transmission Plant	573	-	14,460	-	-	14,460
100			$ -	$ 2,984,283	$ -	$ -	$ 2,984,283
101							

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No. A		FERC Account B	Production I	Transmission J	Distribution K	Customer L	Total M
102	**Total Transmission Expenses**		**$ -**	**$ 77,819,322**	**$ -**	**$ -**	**$ 77,819,322**
103							
104	**Distribution Expenses**						
105	**Operation**						
106	Operations Supervision and Engineering	580	$ -	$ -	$ 7,846,426	$ -	$ 7,846,426
107	Load Dispatching	581	-	-	2,161,146	-	2,161,146
108	Station Expenses	582	-	-	1,215,039	-	1,215,039
109	Overhead Line Expenses	583	-	-	8,147,529	-	8,147,529
110	Underground Line Expenses	584	-	-	3,128,300	-	3,128,300
111	Street Lighting	585	-	-	389,156	-	389,156
112	Meter Expenses	586	-	-	3,263,817	-	3,263,817
113	Customer Installation Expenses	587	-	-	135,513	-	135,513
114	Miscellaneous Distribution Expenses	588	-	-	4,041,605	-	4,041,605
115	Rents	589	-	-	627	-	627
116			$ -	$ -	$ 30,329,157	$ -	$ 30,329,157
117							
118	**Maintenance**						
119	Maintenance Supervision and Engineering	590	$ -	$ -	$ 147,276	$ -	$ 147,276
120	Maintenance of Structures	591	-	-	104,947	-	104,947
121	Maintenance of Station Equipment	592	-	-	2,923,299	-	2,923,299
122	Maintenance of Overhead Lines	593	-	-	12,491,933	-	12,491,933
123	Maintenance of Underground Lines	594	-	-	199,921	-	199,921
124	Maintenance of Line Transformers	595	-	-	8,487	-	8,487
125	Maintenance of Street Lighting and Signal Systems	596	-	-	1,501,335	-	1,501,335
126	Maintenance of Meters	597	-	-	79,995	-	79,995
127	Maintenance of Miscellaneous Distribution Plant	598	-	-	1,256,171	-	1,256,171
128			$ -	$ -	$ 18,713,363	$ -	$ 18,713,363
129							
130	**Total Distribution Expenses**		**$ -**	**$ -**	**$ 49,042,519**	**$ -**	**$ 49,042,519**
131							
132	**Customer and Information Expenses**						
133							
134	Customer Accounts Expenses						
135	Supervision	901	$ -	$ -	$ -	$ 109,431	$ 109,431
136	Meter Reading Expenses	902	-	-	-	14,291,107	14,291,107
137	Customer Records and Collection Expenses	903	-	-	-	27,747,774	27,747,774
138	Uncollectible Accounts	904	-	-	-	4,669,787	4,669,787
139	Miscellaneous Customer Accounts Expenses	905	-	-	-	(16,327,537)	(16,327,537)
140			$ -	$ -	$ -	$ 30,490,562	$ 30,490,562
141							
142	Cust. Service & Information Expense						
143	Supervision	907	$ -	$ -	$ -	$ 174,286	$ 174,286
144	Customer Assistance Expenses	908	-	-	-	240,646	240,646
145	Informational & Instructional Advertising Expenses	909	-	-	-	88,576	88,576
146	Misc Customer Service & Informational Expenses	910	-	-	-	341,418	341,418
147	Supervision	911	-	-	-	10,140,552	10,140,552
148	Demonstrating & Selling Expense	912	-	-	-	3,363,747	3,363,747
149	Advertising Expense	913	-	-	-	489,534	489,534
150	Miscellaneous Sales Expense	916	-	-	-	326,690	326,690
151			$ -	$ -	$ -	$ 15,165,448	$ 15,165,448

Functional Unbundling
Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Production	Transmission	Distribution	Customer	Total
A		B	I	J	K	L	M
152							
153	**Total Customer and Information Expenses**		**$ -**	**$ -**	**$ -**	**$ 45,656,010**	**$ 45,656,010**
154							
155	**General and Administrative Expenses**						
156	Administrative and General Salaries	920	$ 8,849,743	$ 2,761,525	$ 8,519,743	$ 10,760,137	$ 30,891,148
157	Office Supplies and Expenses	921	5,273,986	1,907,125	5,883,784	7,431,014	20,495,909
158	Administrative Expense Transferred	922	11,300	119,435	368,475	465,371	964,581
159	Outside Services Employed	923	5,754,009	1,904,049	1,199,951	1,117,091	9,975,100
160	Property Insurance	924	2,258,015	95,671	532,369	7,004	2,893,058
161	Injuries and Damages	925	1,097,461	233,820	721,372	911,067	2,963,720
162	Employee Pension and Benefits	926	9,931,952	56,333	173,797	219,500	10,381,582
163	Regulatory Commission Expense	928	670,167	158,459	464,281	-	1,292,907
164	General Expenses	930	6,524,359	1,872,619	5,777,327	7,296,562	21,470,867
165	Rents	931	562,234	-	690,548	872,138	2,124,920
166	Maintenance of General Plant	935	895,159	8,006	22,537	21,316	947,017
167			$ 41,828,385	$ 9,117,040	$ 24,354,184	$ 29,101,199	$ 104,400,808
168							
169	**Total Operations & Maintenance Expenses**		**$ 584,944,436**	**$ 86,936,362**	**$ 73,396,703**	**$ 74,757,209**	**$ 820,034,711**
170							
171	**Depreciation & Amortization of CIAC**						
172	Depreciation Expense	403	$ 60,991,236	$ 13,096,126	$ 42,487,851	$ 5,820,131	$ 122,395,343
173	Amortization of CIAC		-	(22,415)	(5,158,416)	-	(5,180,831)
174			**$ 60,991,236**	**$ 13,073,711**	**$ 37,329,434**	**$ 5,820,131**	**$ 117,214,512**
175							
176	**Debt Service**		**$ 88,022,271**	**$ 30,414,912**	**$ 49,568,057**	**$ 65,051**	**$ 168,070,290**
177							
178	**General Fund Transfer**	421.5	**$ 72,762,791**	**$ 5,982,279**	**$ 15,549,336**	**$ 8,705,594**	**$ 103,000,000**
179							
180	**Margin (as defined below)**		**$ (4,641,370)**	**$ (1,662,032)**	**$ 4,835,490**	**$ 10,425,331**	**$ 8,957,418**
181							
182	**Sub-Total Revenue Requirement**		**$ 802,079,364**	**$ 134,745,232**	**$ 180,679,020**	**$ 99,773,315**	**$ 1,217,276,931**
183							
184	**Other Expenses**						
185	Misc Service Revenue	451	$ 29,409	$ -	$ -	$ -	$ 29,409
186	Donations	426	41,353	-	-	-	41,353
187	Taxes Other Than Income	408	18,736	1,540	4,004	2,242	26,522
188	Expenses - Non-utility operations	417	252,602	-	-	2,079,086	2,331,688
189	Franchise Fees		-	-	1,123,778	-	1,123,778
190			**$ 342,100**	**$ 1,540**	**$ 1,127,782**	**$ 2,081,328**	**$ 3,552,750**
191							
192	**Other (Non-Rate) Revenue**						
193	Miscellaneous Nonoperating Income	421	$ 2,684	$ 635	$ 1,859	$ -	$ 5,177
194	Other Revenue		687,951	68,830,887	9,352,089	5,932,775	84,803,701
195	Off-System Sales		-	-	-	-	-
196			**$ 690,634**	**$ 68,831,521**	**$ 9,353,948**	**$ 5,932,775**	**$ 84,808,878**
197							
198	**Total Revenue Requirement**		**$ 801,730,829**	**$ 65,915,251**	**$ 172,452,854**	**$ 95,921,868**	**$ 1,136,020,803**
199							
200	**System Retail Sales (MWh)**		11,813,939	11,813,939	11,813,939	11,813,939	11,813,939
201	Average Rate ($/MWh)		$ 67.86	$ 5.58	$ 14.60	$ 8.12	$ 96.16

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Production	Transmission	Distribution	Customer	Total
A		B	I	J	K	L	M
202							
203	**Comparison to Rate Revenue - FY 2009 Rate Structure**						
204	Base Revenue						
205	Recoverable Fuel						
206	Green Choice						
207	Remove Service Area Street Lighting Fuel Cost						
208							
209							
210							
211	**Over / (Under) Recovery**						
212							
213	*Required Increase / (Decrease) in Rate Revenue*						
214							
215							
216	**Recoverable Fuel Cost**						
217	Fuel	501					
218	Nuclear Fuel Expense	518					
219	Fuel	547					
220	Purchased Power	555					
221	System Control and Load Dispatching	556					
222							
223							
224	**Off-System Sales**						
225							
226	**Net Cost to AE**						
227							
228							
229	**Margin Calculation**						
230	**Cash Sources**						
231	Depreciation Expense	403	$ 60,991,236	$ 13,096,126	$ 42,487,851	$ 5,820,131	$ 122,395,343
232	Amortization of CIAC		-	(22,415)	(5,158,416)	-	(5,180,831)
233	Interest and Dividend Income	419	3,722,393	1,327,129	1,344,570	1,202,516	7,596,609
234			$ 64,713,629	$ 14,400,841	$ 38,674,005	$ 7,022,647	$ 124,811,121
235							
236	**Cash Uses**						
237	Capital From Current Revenue		$ 45,401,917	$ 11,031,054	$ 37,969,016	$ 16,689,024	$ 111,091,011
238	Required Contributions to Decommissioning Reserves		6,716,995	-	-	-	6,716,995
239	Required Contributions to Reserves		7,953,347	1,707,754	5,540,478	758,954	15,960,533
240			$ 60,072,259	$ 12,738,809	$ 43,509,494	$ 17,447,978	$ 133,768,539
241							
242	**Required Margin**		**$ (4,641,370)**	**$ (1,662,032)**	**$ 4,835,490**	**$ 10,425,331**	**$ 8,957,418**
243							
244							
245	**Debt Service Coverage Ratio (DSCR)**						
246	Rate Revenue (assuming required rate increase in Test Year)						
247	Other Operating & Non-Operating Revenue						
248							
249							
250	Operations & Maintenance						
251	Other Expenses						

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Production	Transmission	Distribution	Customer	Total
A		B	I	J	K	L	M
252	Non-Revenue Bonds at 1.0x DSCR						
253							
254							
255	**Balance Available for Revenue Debt Service**						
256							
257	Revenue Debt Service						
258							
259	Revenue Debt Coverage Ratio						
260							
261	**Additional Funds Required to Meet 2.0 DSCR Financial Policy**						
262							
263							
264	**Required Reserve Fund Balance**						
265	(excludes restricted reserves for decommissioning and debt as well a						
266							
267	**Working Capital Reserve Fund**						
268	*Target: 45 days of O&M less fuel and purchased power*						
269							
270	Subtotal Reserves Funds after Working Capital Reserve Fund						
271							
272	**Strategic Reserve Fund**						
273	Contingency Reserve Fund						
274	*Target: 60 days of O&M less fuel and purchased power*						
275	Emergency Reserve Fund						
276	*Target: 60 days of O&M less fuel and purchased power*						
277	Rate Stabilization Fund						
278	*Target: 90 days of Power Cost (Net of ERCOT Fees)*						
279	Subtotal Strategic Reserve Fund						
280							
281	Subtotal Reserves Funds after Strategic Reserve Fund						
282							
283	**Repair and Replacement Fund**						
284	*Target: 1/2 of annual depreciation*						
285							
286	Subtotal Reserves Funds after Repair and Replacement Fund						
287							
288	Total Reserves						
289	Total Reserve Requirements						
290	Undesignated/Unrestricted Reserve						
291	Reserve Deficiency						
292							
293							
294							
295	**Allocation Factors**						
296	1 Production		100.0%	0.0%	0.0%	0.0%	100.0%
297							
298	2 Transmission		0.0%	100.0%	0.0%	0.0%	100.0%
299							
300	3 Distribution		0.0%	0.0%	100.0%	0.0%	100.0%
301							

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.			FERC Account	Production	Transmission	Distribution	Customer	Total
A			B	I	J	K	L	M
302	4	Customer		0.0%	0.0%	0.0%	100.0%	100.0%
303								
304	5	Other Revenue	WP 15 - Oth	0.8%	81.2%	11.0%	7.0%	100.0%
305				687,951	68,830,887	9,352,089	5,932,775	84,803,701
306								
307	6	ADJ Furniture	WP 2 - Plant	15.9%	7.2%	19.6%	57.3%	100.0%
308		Office Furniture (FERC 391): Maintain T-COS Allocation to Tran:		16,996,420	7,666,547	20,874,193	61,176,303	106,713,463
309		T-COS Allocation of FERC 391 based on SQFT		31,300,810	7,666,547	27,698,026	5,235,036	71,900,419
310		Undo Allocation of Non-Transmission Related FERC 391 on SQF		(31,300,810)	-	(27,698,026)	(5,235,036)	(64,233,872)
311		CC&B Direct to Customer		-	-	-	34,813,044	34,813,044
312		Remainder Allocated Based on PAYROLL		15,376,635	6,121,589	18,884,849	23,850,799	64,233,872
313		Redistribute Portion Allocated to Transmission Based on PAYR(		1,619,785	(6,121,589)	1,989,343	2,512,460	-
314								
315	7	ADJ Trans Equip	WP 2 - Plant	9.1%	12.3%	78.6%	0.0%	100.0%
316		Tools and Shop Equip (FERC 394): Maintain T-COS Allocation tc		334,174	448,403	2,876,064	-	3,658,641
317		T-COS Allocation of FERC 394 based on PLTXGNL-N		1,896,424	448,403	1,313,814	-	3,658,641
318		Undo Allocation of Non-Transmission Related FERC 394 on PLT		(1,896,424)	-	(1,313,814)	-	(3,210,238)
319		Remainder Allocated Based on 392 (Transportation Equipment		220,542	1,091,599	1,898,097	-	3,210,238
320		Redistribute Portion Allocated to Transmission Based on 392 (1		113,631	(1,091,599)	977,967	-	0
321								
322	8	SQFT	WP 4 - SqFt	43.5%	10.7%	38.5%	7.3%	100.0%
323		Useable Square Footage		135,281	33,135	119,710	22,626	310,751
324								
325	9	PAYROLL	WP 3.1 - Lab	23.9%	9.5%	29.4%	37.1%	100.0%
326		Total Electric Labor		31,776,341	12,650,472	39,026,186	49,288,491	132,741,490
327								
328	10	PAYXAG	WP 3.1 - Lab	23.9%	9.5%	29.4%	37.1%	100.0%
329		Total Electric Labor, Excluding Administrative and General Labc		21,341,235	8,496,076	26,211,747	33,104,519	89,153,577
330								
331	11	INSUR	WP 39 - T-C	71.0%	4.4%	24.3%	0.3%	100.0%
332		Insurance Allocator Developed by AE in T-COS		1	0	0	0	1
333								
334	12	PLTXGNL-N	WP 2 - Plant	51.8%	12.3%	35.9%	0.0%	100.0%
335		Net Electric Plant In Service, Excluding General Plant		1,096,116,536	259,173,086	759,372,950	-	2,114,662,571
336								
337	13	TOMXFP		50.1%	22.5%	14.2%	13.2%	100.0%
338		Total O&M, Excluding Commodity Fuel, Purchased Power and /		173,298,434	77,819,322	49,042,519	45,656,010	345,816,285
339								
340	14	OMAG		47.8%	19.3%	16.3%	16.6%	100.0%
341		Total O&M, Including A&G but Excluding Commodity Fuel and		215,126,819	86,936,362	73,396,703	74,757,209	450,217,094
342								
343	15	GNLPLT-N	WP 2 - Plant	28.4%	11.1%	31.1%	29.4%	100.0%
344		Net General Plant In Service		42,094,838	16,385,987	46,129,483	43,630,377	148,240,685
345								
346	16	TTRRXGFT		70.6%	5.8%	15.1%	8.5%	100.0%
347		Total Revenue Requirement, Excluding General Fund Transfer a		728,968,038	59,932,972	155,779,740	87,216,274	1,031,897,025
348								
349	17	FERC 417	WP 7 - City S	10.8%	0.0%	0.0%	89.2%	100.0%
350		Allocation of Electric Utility Expenses within FERC 417		252,602	-	-	2,079,086	2,331,688
351		311 Call Center - Net Cost Attributable to AE		-	-	-	2,079,086	2,079,086
352		RMEC-Generation (Unit 2234)		251,657	-	-	-	251,657

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.			FERC Account	Production	Transmission	Distribution	Customer	Total
A			B	I	J	K	L	M
353		Bchp-Gas Turbine (Unit 2227)		945	-	-	-	945
354								
355	18	392	WP 39 - T-C	6.9%	34.0%	59.1%	0.0%	100.0%
356		Transportation Equipment Allocation		0	0	1	-	1
357								
358	19	397	WP 39 - T-C	42.9%	12.2%	24.6%	20.3%	100.0%
359		Communication Equipment Allocation		0	0	0	0	1
360								
361	20	Interest	WP 18 - Inte	49.0%	17.5%	17.7%	15.8%	100.0%
362		Functionalization of Interest Income in the Test Year		3,722,393	1,327,129	1,344,570	1,202,516	7,596,609
363								
364	21	PAYXAGT	WP 3.1 - Lal	26.5%	0.0%	32.5%	41.0%	100.0%
365		Total Electric Labor, Excluding Transmission, Administrative an		21,341,235	-	26,211,747	33,104,519	80,657,501
366								
367	22	CIP-Total	WP 14.1 - Cl	40.9%	9.9%	34.2%	15.0%	100.0%
368		Average Capital Improvement Spending (FY 2009 actual, FY 20:		90,803,834	22,062,109	75,938,032	33,378,048	222,182,023
369								
370	23	ACC P&I	WP 5 - Debt	52.4%	18.1%	29.5%	0.0%	100.0%
371		Accrual Debt Service (FY 2011)		88,022,271	30,414,912	49,568,057	65,051	168,070,290
372								
373	24	TRAN/DIST		0.0%	50.0%	50.0%	0.0%	100.0%
374					1	1		2
375								
376	25	DEPR	WP 2 - Plant	49.8%	10.7%	34.7%	4.8%	100.0%
377		Depreciation of Electric Plant In Service		60,991,236	13,096,126	42,487,850	5,820,130	122,395,343
378								
379	26	AMORT CIAC	WP 43 - Am	0.0%	0.4%	99.6%	0.0%	100.0%
380		Amortization of Contributions in Aid of Construction		-	22,415	5,158,416	-	5,180,831
381								
382	27	Misc Op Rev 4874	WP 39 - T-C	90.0%	0.0%	10.0%	0.0%	100.0%
383				108,000	-	12,003	-	120,003
384								
385	28	Misc Non-Op Rev 4874	WP 39 - T-C	8.7%	1.2%	90.1%	0.0%	100.0%
386				1,509	207	15,631	-	17,346
387								
388	29	Misc Non-Op Rev 4952	WP 39 - T-C	86.2%	0.0%	13.8%	0.0%	100.0%
389				20,885	-	3,343	-	24,228
390								
391	30	ECCCOM	WP 39 - T-C	36.4%	35.1%	28.5%	0.0%	100.0%
392		ECC Communication Equipment		0	0	0	-	1

Functional Unbundling
Purpose: Develop the Functionalized Test Year Revenue Requirement

Detailed Adjustments:

Line No.		FERC Account	PCM & Normalization WP 27 & 44	Labor Costs WP 3	FPP Scrubber O&M Increase WP 13	STP & FPP O&M WP 11	SHEC O&M WP 12	City Services WP 7	Uncollectible Accounts WP 17	Remove Legislative Advocacy WP 42
A		B	N	O	P	Q	R	S	T	U
1	**Power Production Expenses**									
2	Steam Power Generation									
3	**Operation**									
4	Operation Supervision and Engineering	500	$ -	$ 64,542	$ -	$ (28,211)	$ -	$ -	$ -	$ -
5	Fuel - Recoverable	501	(168,380,271)	-	-	-	-	-	-	-
6	Fuel - Non-Recoverable	501	-	13,667	-	854,237	-	-	-	-
7	Steam Expenses	502	-	128,352	2,433,504	(284,260)	-	-	-	-
8	Steam from other Sources	503	-	-	-	-	-	-	-	-
9	Steam Transferred	504	-	-	-	-	-	-	-	-
10	Electric Expenses	505	-	36,790	-	(3,319,264)	-	-	-	-
11	Miscellaneous Steam Expenses	506	-	4,347	-	68,000	-	-	-	-
12	Rents	507	-	-	-	-	-	-	-	-
13										
14										
15	**Maintenance**									
16	Maintenance Supervision	510	$ -	$ 112,362	$ -	$ 98,145	$ -	$ -	$ -	$ -
17	Maintenance of Structures	511	-	2,967	-	43,670	-	-	-	-
18	Maintenance of Boiler Plant	512	-	24,930	-	(25,300)	-	-	-	-
19	Maintenance of Electric Plant	513	-	20,917	-	1,113,366	-	-	-	-
20	Maintenance of Miscellaneous Steam Plant	514	-	64,113	-	308,275	-	-	-	-
21	Rents	515	-	-	-	-	-	-	-	-
22										
23										
24	Nuclear Power Generation									
25	**Operation**									
26	Operation Supervision	517	$ -	$ 25,989	$ -	$ (310,355)	$ -	$ -	$ -	$ -
27	Nuclear Fuel Expense	518	2,480,877	-	-	-	-	-	-	-
28	Coolants and Water	519	-	-	-	83,777	-	-	-	-
29	Steam Expenses	520	-	-	-	501,905	-	-	-	-
30	Electric Expenses	523	-	-	-	191,435	-	-	-	-
31	Misc Nuclear Power Expenses	524	-	-	-	189,331	-	-	-	-
32	Rents	525	-	-	-	-	-	-	-	-
33										
34										
35	**Maintenance**									
36	Maintenance Supervision	528	$ -	$ -	$ -	$ 1,152,420	$ -	$ -	$ -	$ -
37	Maintenance of Structures	529	-	-	-	341,657	-	-	-	-
38	Maintenance of Reactor Plant	530	-	-	-	1,524,030	-	-	-	-
39	Maintenance of Electric Plant	531	-	-	-	713,296	-	-	-	-
40	Maintenance of Miscellaneous	532	-	-	-	86,131	-	-	-	-
41										
42										
43	Hydraulic Power Generation									
44	**Maintenance**									
45	Maintenance Supervision	541	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Maintenance of Structures	542	-	-	-	-	-	-	-	-
47	Maintenance of Reservoirs, Dams & Waterways	543	-	-	-	-	-	-	-	-
48	Maintenance of Electric Plant	544	-	-	-	-	-	-	-	-
49	Maintenance of Miscellaneous Hydraulic Plant	545	-	-	-	-	-	-	-	-
50										
51										

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Detailed Adjustments:

Line No.		FERC Account	PCM & Normalization WP 27 & 44	Labor Costs WP 3	FPP Scrubber O&M Increase WP 13	STP & FPP O&M WP 11	SHEC O&M WP 12	City Services WP 7	Uncollectible Accounts WP 17	Remove Legislative Advocacy WP 42
A		B	N	O	P	Q	R	S	T	U
52	Other Power Generation									
53	**Operation**									
54	Operation Supervision	546	$ -	$ 33,898	$ -	$ -	$ -	$ -	$ -	$ -
55	Fuel	547	122,424,961	-	-	-	-	-	-	-
56	Generation Expenses	548	-	59,468	-	-	1,448,193	-	-	-
57	Miscellaneous Other Power Generation Expenses	549	-	9,712	-	-	-	-	-	-
58	Rents	550	-	(74)	-	-	-	-	-	-
59	Energy Efficiency		-	-	-	-	-	-	-	-
60	Green Building		-	-	-	-	-	-	-	-
61	Solar Rebate		-	-	-	-	-	-	-	-
62										
63										
64	**Maintenance**									
65	Maintenance Supervision and Engineering	551	$ -	$ (1,394)	$ -	$ -	$ -	$ -	$ -	$ -
66	Maintenance of Structures	552	-	7,270	-	-	-	-	-	-
67	Maintenance of Generating and Electric Equipment	553	-	103,015	-	-	2,699,254	-	-	-
68	Maintenance of Misc Other Power Generation Plant	554	-	25,445	-	-	-	-	-	-
69										
70										
71	Other Power Supply									
72	Purchased Power - Recoverable	555	$ 17,681,726	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Purchased Power - Non-Recoverable	555	(16,453,605)	-	-	-	-	-	-	-
74	System Control and Load Dispatching - Recoverable	556	8,288,917	-	-	-	-	-	-	-
75	System Control and Load Dispatching - Non-Recoverable	556	(8,189,149)	70,336	-	-	-	-	-	-
76	Other Power Expenses	557	-	15,548	-	12,303	-	-	-	-
77										
78										
79	**Total Power Production Expense**									
80										
81	**Transmission Expense**									
82	**Operation**									
83	Operations Supervision and Engineering	560	$ -	$ (247,864)	$ -	$ -	$ -	$ -	$ -	$ -
84	Load Dispatching	561	-	51,291	-	-	-	-	-	-
85	Station Expenses	562	-	7,772	-	-	-	-	-	-
86	Overhead Line Expenses	563	-	72,211	-	-	-	-	-	-
87	Underground Line Expenses	564	-	-	-	-	-	-	-	-
88	Transmission of Electricity by Others	565	-	18	-	-	-	-	-	-
89	Miscellaneous Transmission Expenses	566	-	13,304	-	-	-	-	-	-
90	Rents	567	-	-	-	-	-	-	-	-
91										
92										
93	**Maintenance**									
94	Maintenance Supervision and Engineering	568	$ -	$ 12	$ -	$ -	$ -	$ -	$ -	$ -
95	Maintenance of Structures	569	-	167	-	-	-	-	-	-
96	Maintenance of Station Equipment	570	-	101,010	-	16,411	-	-	-	-
97	Maintenance of Overhead Lines	571	-	18,788	-	-	-	-	-	-
98	Maintenance of Underground Lines	572	-	-	-	-	-	-	-	-
99	Maintenance of Miscellaneous Transmission Plant	573	-	(3,406)	-	-	-	-	-	-
100										
101										

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Detailed Adjustments:

Line No.		FERC Account	PCM & Normalization WP 27 & 44	Labor Costs WP 3	FPP Scrubber O&M Increase WP 13	STP & FPP O&M WP 11	SHEC O&M WP 12	City Services WP 7	Uncollectible Accounts WP 17	Remove Legislative Advocacy WP 42
A		B	N	O	P	Q	R	S	T	U
102	**Total Transmission Expenses**									
103										
104	**Distribution Expenses**									
105	**Operation**									
106	Operations Supervision and Engineering	580	$ -	$ (749,001)	$ -	$ -	$ -	$ -	$ -	$ -
107	Load Dispatching	581	-	(42,702)	-	-	-	-	-	-
108	Station Expenses	582	-	7,135	-	-	-	-	-	-
109	Overhead Line Expenses	583	-	425,655	-	-	-	-	-	-
110	Underground Line Expenses	584	-	275,055	-	-	-	-	-	-
111	Street Lighting	585	-	(56,721)	-	-	-	-	-	-
112	Meter Expenses	586	-	117,119	-	-	-	-	-	-
113	Customer Installation Expenses	587	-	-	-	-	-	-	-	-
114	Miscellaneous Distribution Expenses	588	-	44,131	-	-	-	-	-	-
115	Rents	589	-	627	-	-	-	-	-	-
116										
117										
118	**Maintenance**									
119	Maintenance Supervision and Engineering	590	$ -	$ 10,150	$ -	$ -	$ -	$ -	$ -	$ -
120	Maintenance of Structures	591	-	-	-	-	-	-	-	-
121	Maintenance of Station Equipment	592	-	172,493	-	-	-	-	-	-
122	Maintenance of Overhead Lines	593	-	(2,613)	-	-	-	-	-	-
123	Maintenance of Underground Lines	594	-	64	-	-	-	-	-	-
124	Maintenance of Line Transformers	595	-	960	-	-	-	-	-	-
125	Maintenance of Street Lighting and Signal Systems	596	-	118,456	-	-	-	-	-	-
126	Maintenance of Meters	597	-	11,868	-	-	-	-	-	-
127	Maintenance of Miscellaneous Distribution Plant	598	-	84,864	-	-	-	-	-	-
128										
129										
130	**Total Distribution Expenses**									
131										
132	**Customer and Information Expenses**									
133										
134	Customer Accounts Expenses									
135	Supervision	901	$ -	$ 29,568	$ -	$ -	$ -	$ -	$ -	$ -
136	Meter Reading Expenses	902	-	172,187	-	-	-	(96,324)	-	-
137	Customer Records and Collection Expenses	903	-	679,770	-	-	-	-	-	-
138	Uncollectible Accounts	904	-	-	-	-	-	-	1,020,593	-
139	Miscellaneous Customer Accounts Expenses	905	-	-	-	-	-	(1,339,036)	-	-
140										
141										
142	Cust. Service & Information Expense									
143	Supervision	907	$ -	$ 116,873	$ -	$ -	$ -	$ -	$ -	$ -
144	Customer Assistance Expenses	908	-	220,729	-	-	-	(30,760)	-	-
145	Informational & Instructional Advertising Expenses	909	-	(165)	-	-	-	-	-	-
146	Misc Customer Service & Informational Expenses	910	-	35,341	-	-	-	-	-	-
147	Supervision	911	-	148,205	-	-	-	1,729,942	-	-
148	Demonstrating & Selling Expense	912	-	214,577	-	-	-	-	-	-
149	Advertising Expense	913	-	37,040	-	-	-	-	-	-
150	Miscellaneous Sales Expense	916	-	(2,540)	-	-	-	-	-	(110,000)
151										

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Detailed Adjustments:

Line No.		FERC Account	PCM & Normalization WP 27 & 44	Labor Costs WP 3	FPP Scrubber O&M Increase WP 13	STP & FPP O&M WP 11	SHEC O&M WP 12	City Services WP 7	Uncollectible Accounts WP 17	Remove Legislative Advocacy WP 42
A		B	N	O	P	Q	R	S	T	U
152										
153	**Total Customer and Information Expenses**									
154										
155	**General and Administrative Expenses**									
156	Administrative and General Salaries	920	$ -	$ 5,936,109	$ -	$ 412,086	$ -	$ (31,568)	$ -	$ -
157	Office Supplies and Expenses	921	-	(3,744)	-	(3,739)	-	(5,745,277)	-	-
158	Administrative Expense Transferred	922	-	-	-	1,251,992	-	-	-	-
159	Outside Services Employed	923	-	183	-	(420,272)	-	(25,109)	-	(145,689)
160	Property Insurance	924	-	-	-	(52,113)	-	-	-	-
161	Injuries and Damages	925	-	(12,972)	-	197,431	-	1,087,989	-	-
162	Employee Pension and Benefits	926	-	(17,510,842)	-	584,379	-	-	-	-
163	Regulatory Commission Expense	928	-	-	-	-	-	-	-	-
164	General Expenses	930	-	134,143	-	(621,698)	-	(37,995)	-	(58,553)
165	Rents	931	-	-	-	-	-	-	-	-
166	Maintenance of General Plant	935	-	(112)	-	67,414	-	-	-	-
167										
168										
169	**Total Operations & Maintenance Expenses**									
170										
171	**Depreciation & Amortization of CIAC**									
172	Depreciation Expense	403	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
173	Amortization of CIAC		-	-	-	-	-	-	-	-
174										
175										
176	**Debt Service**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
177										
178	**General Fund Transfer**	421.5	$ -	$ -	$ -	$ -	$ -	$ 8,000,000	$ -	$ -
179										
180	**Margin (as defined below)**									
181										
182	**Sub-Total Revenue Requirement**									
183										
184	**Other Expenses**									
185	Misc Service Revenue	451	$ -	$ -	$ -	$ -	$ -	$ 7,850	$ -	$ -
186	Donations	426	-	-	-	3,011	-	-	-	-
187	Taxes Other Than Income	408	-	-	-	17,405	-	-	-	-
188	Expenses - Non-utility operations	417	-	-	-	-	-	(3,879,536)	-	-
189	Franchise Fees		-	-	-	-	-	-	-	-
190										
191										
192	**Other (Non-Rate) Revenue**									
193	Miscellaneous Nonoperating Income	421	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
194	Other Revenue		-	-	-	-	-	-	-	-
195	Off-System Sales		-	-	-	-	-	-	-	-
196										
197										
198	**Total Revenue Requirement**									
199										
200	**System Retail Sales (MWh)**									
201	Average Rate ($/MWh)									

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Detailed Adjustments: PCM & Normalization WP 27 & 44	Labor Costs WP 3	FPP Scrubber O&M Increase WP 13	STP & FPP O&M WP 11	SHEC O&M WP 12	City Services WP 7	Uncollectible Accounts WP 17	Remove Legislative Advocacy WP 42
A		B	N	O	P	Q	R	S	T	U
202										
203	**Comparison to Rate Revenue - FY 2009 Rate Structure**									
204	Base Revenue		$ (12,678,423)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
205	Recoverable Fuel									
206	Green Choice		(21,626,212)	-	-	-	-	-	-	-
207	Remove Service Area Street Lighting Fuel Cost		-	-	-	-	-	-	-	-
208										
209										
210										
211	**Over / (Under) Recovery**									
212										
213	*Required Increase / (Decrease) in Rate Revenue*									
214										
215										
216	**Recoverable Fuel Cost**									
217	Fuel	501								
218	Nuclear Fuel Expense	518								
219	Fuel	547								
220	Purchased Power	555								
221	System Control and Load Dispatching	556								
222										
223										
224	**Off-System Sales**									
225										
226	**Net Cost to AE**									
227										
228										
229	**Margin Calculation**									
230	**Cash Sources**									
231	Depreciation Expense	403	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
232	Amortization of CIAC		-	-	-	-	-	-	-	-
233	Interest and Dividend Income	419	-	-	-	-	-	-	-	-
234										
235										
236	**Cash Uses**									
237	Capital From Current Revenue		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
238	Required Contributions to Decommissioning Reserves		-	-	-	-	-	-	-	-
239	Required Contributions to Reserves		-	-	-	-	-	-	-	-
240										
241										
242	**Required Margin**									
243										

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Remove Non-Electric Expense WP 2, 5, 19, 38 & 42	Remove Non-Electric Revenue WP 15	Remove Holly Write-Off WP 8	Franchise Fees WP 9	Power Factor Revenue WP 10 & 27	Re-aggregated Classes WP 27	Off-System Sales WP 15 & 20	Interest Income WP 18
A		B	V	W	X	Y	Z	AA	AB	AC
1	**Power Production Expenses**									
2	Steam Power Generation									
3	**Operation**									
4	Operation Supervision and Engineering	500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Fuel - Recoverable	501	-	-	-	-	-	-	-	-
6	Fuel - Non-Recoverable	501	-	-	-	-	-	-	-	-
7	Steam Expenses	502	-	-	-	-	-	-	-	-
8	Steam from other Sources	503	-	-	-	-	-	-	-	-
9	Steam Transferred	504	-	-	-	-	-	-	-	-
10	Electric Expenses	505	-	-	-	-	-	-	-	-
11	Miscellaneous Steam Expenses	506	-	-	-	-	-	-	-	-
12	Rents	507	-	-	-	-	-	-	-	-
13										
14										
15	**Maintenance**									
16	Maintenance Supervision	510	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Maintenance of Structures	511	-	-	-	-	-	-	-	-
18	Maintenance of Boiler Plant	512	-	-	-	-	-	-	-	-
19	Maintenance of Electric Plant	513	-	-	-	-	-	-	-	-
20	Maintenance of Miscellaneous Steam Plant	514	(11,970)	-	-	-	-	-	-	-
21	Rents	515	-	-	-	-	-	-	-	-
22										
23										
24	Nuclear Power Generation									
25	**Operation**									
26	Operation Supervision	517	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Nuclear Fuel Expense	518	-	-	-	-	-	-	-	-
28	Coolants and Water	519	-	-	-	-	-	-	-	-
29	Steam Expenses	520	-	-	-	-	-	-	-	-
30	Electric Expenses	523	-	-	-	-	-	-	-	-
31	Misc Nuclear Power Expenses	524	-	-	-	-	-	-	-	-
32	Rents	525	-	-	-	-	-	-	-	-
33										
34										
35	**Maintenance**									
36	Maintenance Supervision	528	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37	Maintenance of Structures	529	-	-	-	-	-	-	-	-
38	Maintenance of Reactor Plant	530	-	-	-	-	-	-	-	-
39	Maintenance of Electric Plant	531	-	-	-	-	-	-	-	-
40	Maintenance of Miscellaneous	532	-	-	-	-	-	-	-	-
41										
42										
43	Hydraulic Power Generation									
44	**Maintenance**									
45	Maintenance Supervision	541	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Maintenance of Structures	542	-	-	-	-	-	-	-	-
47	Maintenance of Reservoirs, Dams & Waterways	543	-	-	-	-	-	-	-	-
48	Maintenance of Electric Plant	544	-	-	-	-	-	-	-	-
49	Maintenance of Miscellaneous Hydraulic Plant	545	-	-	-	-	-	-	-	-
50										
51										

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Remove Non-Electric Expense WP 2, 5, 19, 38 & 42	Remove Non-Electric Revenue WP 15	Remove Holly Write-Off WP 8	Franchise Fees WP 9	Power Factor Revenue WP 10 & 27	Re-aggregated Classes WP 27	Off-System Sales WP 15 & 20	Interest Income WP 18
A		B	V	W	X	Y	Z	AA	AB	AC
52	Other Power Generation									
53	**Operation**									
54	Operation Supervision	546	$ (613,208)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	Fuel	547	-	-	-	-	-	-	-	-
56	Generation Expenses	548	(330)	-	-	-	-	-	-	-
57	Miscellaneous Other Power Generation Expenses	549	(32,164)	-	-	-	-	-	-	-
58	Rents	550	-	-	-	-	-	-	-	-
59	Energy Efficiency		-	-	-	-	-	-	-	-
60	Green Building		-	-	-	-	-	-	-	-
61	Solar Rebate		-	-	-	-	-	-	-	-
62										
63										
64	**Maintenance**									
65	Maintenance Supervision and Engineering	551	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	Maintenance of Structures	552	(210)	-	-	-	-	-	-	-
67	Maintenance of Generating and Electric Equipment	553	-	-	-	-	-	-	-	-
68	Maintenance of Misc Other Power Generation Plant	554	(455)	-	-	-	-	-	-	-
69										
70										
71	Other Power Supply									
72	Purchased Power - Recoverable	555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Purchased Power - Non-Recoverable	555	-	-	-	-	-	-	-	-
74	System Control and Load Dispatching - Recoverable	556	-	-	-	-	-	-	-	-
75	System Control and Load Dispatching - Non-Recoverable	556	-	-	-	-	-	-	-	-
76	Other Power Expenses	557	-	-	-	-	-	-	-	-
77										
78										
79	**Total Power Production Expense**									
80										
81	**Transmission Expense**									
82	**Operation**									
83	Operations Supervision and Engineering	560	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84	Load Dispatching	561	-	-	-	-	-	-	-	-
85	Station Expenses	562	-	-	-	-	-	-	-	-
86	Overhead Line Expenses	563	-	-	-	-	-	-	-	-
87	Underground Line Expenses	564	-	-	-	-	-	-	-	-
88	Transmission of Electricity by Others	565	-	-	-	-	-	-	-	-
89	Miscellaneous Transmission Expenses	566	-	-	-	-	-	-	-	-
90	Rents	567	-	-	-	-	-	-	-	-
91										
92										
93	**Maintenance**									
94	Maintenance Supervision and Engineering	568	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
95	Maintenance of Structures	569	-	-	-	-	-	-	-	-
96	Maintenance of Station Equipment	570	-	-	-	-	-	-	-	-
97	Maintenance of Overhead Lines	571	-	-	-	-	-	-	-	-
98	Maintenance of Underground Lines	572	-	-	-	-	-	-	-	-
99	Maintenance of Miscellaneous Transmission Plant	573	-	-	-	-	-	-	-	-
100										
101										

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Remove Non-Electric Expense WP 2, 5, 19, 38 & 42	Remove Non-Electric Revenue WP 15	Remove Holly Write-Off WP 8	Franchise Fees WP 9	Power Factor Revenue WP 10 & 27	Re-aggregated Classes WP 27	Off-System Sales WP 15 & 20	Interest Income WP 18
A		B	V	W	X	Y	Z	AA	AB	AC
102	**Total Transmission Expenses**									
103										
104	**Distribution Expenses**									
105	**Operation**									
106	Operations Supervision and Engineering	580	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
107	Load Dispatching	581	-	-	-	-	-	-	-	-
108	Station Expenses	582	-	-	-	-	-	-	-	-
109	Overhead Line Expenses	583	-	-	-	-	-	-	-	-
110	Underground Line Expenses	584	(573)	-	-	-	-	-	-	-
111	Street Lighting	585	-	-	-	-	-	-	-	-
112	Meter Expenses	586	-	-	-	-	-	-	-	-
113	Customer Installation Expenses	587	-	-	-	-	-	-	-	-
114	Miscellaneous Distribution Expenses	588	-	-	-	-	-	-	-	-
115	Rents	589	-	-	-	-	-	-	-	-
116										
117										
118	**Maintenance**									
119	Maintenance Supervision and Engineering	590	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
120	Maintenance of Structures	591	-	-	-	-	-	-	-	-
121	Maintenance of Station Equipment	592	-	-	-	-	-	-	-	-
122	Maintenance of Overhead Lines	593	-	-	-	-	-	-	-	-
123	Maintenance of Underground Lines	594	-	-	-	-	-	-	-	-
124	Maintenance of Line Transformers	595	-	-	-	-	-	-	-	-
125	Maintenance of Street Lighting and Signal Systems	596	-	-	-	-	-	-	-	-
126	Maintenance of Meters	597	-	-	-	-	-	-	-	-
127	Maintenance of Miscellaneous Distribution Plant	598	-	-	-	-	-	-	-	-
128										
129										
130	**Total Distribution Expenses**									
131										
132	**Customer and Information Expenses**									
133										
134	Customer Accounts Expenses									
135	Supervision	901	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
136	Meter Reading Expenses	902	-	-	-	-	-	-	-	-
137	Customer Records and Collection Expenses	903	-	-	-	-	-	-	-	-
138	Uncollectible Accounts	904	-	-	-	-	-	-	-	-
139	Miscellaneous Customer Accounts Expenses	905	-	-	-	-	-	-	-	-
140										
141										
142	Cust. Service & Information Expense									
143	Supervision	907	$ (320)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
144	Customer Assistance Expenses	908	-	-	-	-	-	-	-	-
145	Informational & Instructional Advertising Expenses	909	-	-	-	-	-	-	-	-
146	Misc Customer Service & Informational Expenses	910	-	-	-	-	-	-	-	-
147	Supervision	911	-	-	-	-	-	-	-	-
148	Demonstrating & Selling Expense	912	(57,402)	-	-	-	-	-	-	-
149	Advertising Expense	913	-	-	-	-	-	-	-	-
150	Miscellaneous Sales Expense	916	-	-	-	-	-	-	-	-
151										

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Remove Non-Electric Expense WP 2, 5, 19, 38 & 42	Remove Non-Electric Revenue WP 15	Remove Holly Write-Off WP 8	Franchise Fees WP 9	Power Factor Revenue WP 10 & 27	Re-aggregated Classes WP 27	Off-System Sales WP 15 & 20	Interest Income WP 18
A		B	V	W	X	Y	Z	AA	AB	AC
152										
153	**Total Customer and Information Expenses**									
154										
155	**General and Administrative Expenses**									
156	Administrative and General Salaries	920	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
157	Office Supplies and Expenses	921	(2,410)	-	(1,756,428)	-	-	-	-	-
158	Administrative Expense Transferred	922	-	-	-	-	-	-	-	-
159	Outside Services Employed	923	-	-	-	-	-	-	-	-
160	Property Insurance	924	(120,869)	-	-	-	-	-	-	-
161	Injuries and Damages	925	-	-	-	-	-	-	-	-
162	Employee Pension and Benefits	926	-	-	-	-	-	-	-	-
163	Regulatory Commission Expense	928	-	-	-	-	-	-	-	-
164	General Expenses	930	(324)	-	-	-	-	-	-	-
165	Rents	931	-	-	-	-	-	-	-	-
166	Maintenance of General Plant	935	-	-	-	-	-	-	-	-
167										
168										
169	**Total Operations & Maintenance Expenses**									
170										
171	**Depreciation & Amortization of CIAC**									
172	Depreciation Expense	403	$ (3,619,223)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
173	Amortization of CIAC		-	-	-	-	-	-	-	-
174										
175										
176	**Debt Service**		$ (3,951,869)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
177										
178	**General Fund Transfer**	421.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
179										
180	**Margin (as defined below)**									
181										
182	**Sub-Total Revenue Requirement**									
183										
184	**Other Expenses**									
185	Misc Service Revenue	451	$ (497)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
186	Donations	426	-	-	-	-	-	-	-	-
187	Taxes Other Than Income	408	-	-	-	-	-	-	-	-
188	Expenses - Non-utility operations	417	(10,077,720)	-	-	-	-	-	-	-
189	Franchise Fees		-	-	-	1,123,778	-	-	-	-
190										
191										
192	**Other (Non-Rate) Revenue**									
193	Miscellaneous Nonoperating Income	421	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
194	Other Revenue		-	(13,799,872)	-	-	-	-	(18,252,299)	-
195	Off-System Sales		-	-	-	-	-	-	(16,877,957)	-
196										
197										
198	**Total Revenue Requirement**									
199										
200	**System Retail Sales (MWh)**									
201	Average Rate ($/MWh)									

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Remove Non-Electric Expense WP 2, 5, 19, 38 & 42	Remove Non-Electric Revenue WP 15	Remove Holly Write-Off WP 8	Franchise Fees WP 9	Power Factor Revenue WP 10 & 27	Re-aggregated Classes WP 27	Off-System Sales WP 15 & 20	Interest Income WP 18
A		B	V	W	X	Y	Z	AA	AB	AC
202										
203	**Comparison to Rate Revenue - FY 2009 Rate Structure**									
204	Base Revenue		$ -	$ -	$ -	$ -	$ 2,305,760	$ 4,576,371	$ -	$ -
205	Recoverable Fuel									
206	Green Choice		-	-	-	-	-	-	-	-
207	Remove Service Area Street Lighting Fuel Cost		-	-	-	-	-	-	-	-
208										
209										
210										
211	**Over / (Under) Recovery**									
212										
213	*Required Increase / (Decrease) in Rate Revenue*									
214										
215										
216	**Recoverable Fuel Cost**									
217	Fuel	501								
218	Nuclear Fuel Expense	518								
219	Fuel	547								
220	Purchased Power	555								
221	System Control and Load Dispatching	556								
222										
223										
224	**Off-System Sales**									
225										
226	**Net Cost to AE**									
227										
228										
229	**Margin Calculation**									
230	**Cash Sources**									
231	Depreciation Expense	403	$ (3,619,223)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
232	Amortization of CIAC		-	-	-	-	-	-	-	-
233	Interest and Dividend Income	419	-	-	-	-	-	-	-	(9,804,953)
234										
235										
236	**Cash Uses**									
237	Capital From Current Revenue		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
238	Required Contributions to Decommissioning Reserves		-	-	-	-	-	-	-	-
239	Required Contributions to Reserves		-	-	-	-	-	-	-	-
240										
241										
242	**Required Margin**									
243										

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Normalize Capital Outlay WP 14	FERC Transition SHEC O&M WP 24	FY 2011 Debt Service WP 5	Net Additional Depreciation WP 2	Transmission COS Off-Set WP 15	Reclassify Prepaid Insurance WP 35	STP Regulatory Asset Deferral WP 33	New Building Lease WP 25
A		B	AD	AE	AF	AG	AH	AI	AJ	AK
1	**Power Production Expenses**									
2	Steam Power Generation									
3	**Operation**									
4	Operation Supervision and Engineering	500	$ -	$ (719,337)	$ -	$ -	$ -	$ -	$ -	$ -
5	Fuel - Recoverable	501	-	-	-	-	-	-	-	-
6	Fuel - Non-Recoverable	501	-	-	-	-	-	-	-	-
7	Steam Expenses	502	-	(30,386)	-	-	-	-	-	-
8	Steam from other Sources	503	-	-	-	-	-	-	-	-
9	Steam Transferred	504	-	-	-	-	-	-	-	-
10	Electric Expenses	505	-	(30,163)	-	-	-	-	-	-
11	Miscellaneous Steam Expenses	506	-	(225,344)	-	-	-	-	-	-
12	Rents	507	-	(146)	-	-	-	-	-	-
13										
14										
15	**Maintenance**									
16	Maintenance Supervision	510	$ -	$ (21,823)	$ -	$ -	$ -	$ -	$ -	$ -
17	Maintenance of Structures	511	-	(34,898)	-	-	-	-	-	-
18	Maintenance of Boiler Plant	512	-	(555,089)	-	-	-	-	-	-
19	Maintenance of Electric Plant	513	-	(1,631,583)	-	-	-	-	-	-
20	Maintenance of Miscellaneous Steam Plant	514	-	(203,718)	-	-	-	-	-	-
21	Rents	515	-	-	-	-	-	-	-	-
22										
23										
24	Nuclear Power Generation									
25	**Operation**									
26	Operation Supervision	517	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Nuclear Fuel Expense	518	-	-	-	-	-	-	-	-
28	Coolants and Water	519	-	-	-	-	-	-	-	-
29	Steam Expenses	520	-	-	-	-	-	-	-	-
30	Electric Expenses	523	-	-	-	-	-	-	-	-
31	Misc Nuclear Power Expenses	524	-	-	-	-	-	-	-	-
32	Rents	525	-	-	-	-	-	-	-	-
33										
34										
35	**Maintenance**									
36	Maintenance Supervision	528	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37	Maintenance of Structures	529	-	-	-	-	-	-	-	-
38	Maintenance of Reactor Plant	530	-	-	-	-	-	-	-	-
39	Maintenance of Electric Plant	531	-	-	-	-	-	-	-	-
40	Maintenance of Miscellaneous	532	-	-	-	-	-	-	-	-
41										
42										
43	Hydraulic Power Generation									
44	**Maintenance**									
45	Maintenance Supervision	541	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Maintenance of Structures	542	-	-	-	-	-	-	-	-
47	Maintenance of Reservoirs, Dams & Waterways	543	-	-	-	-	-	-	-	-
48	Maintenance of Electric Plant	544	-	-	-	-	-	-	-	-
49	Maintenance of Miscellaneous Hydraulic Plant	545	-	-	-	-	-	-	-	-
50										
51										

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Normalize Capital Outlay WP 14	FERC Transition SHEC O&M WP 24	FY 2011 Debt Service WP 5	Net Additional Depreciation WP 2	Transmission COS Off-Set WP 15	Reclassify Prepaid Insurance WP 35	STP Regulatory Asset Deferral WP 33	New Building Lease WP 25
A		B	AD	AE	AF	AG	AH	AI	AJ	AK
52	Other Power Generation									
53	**Operation**									
54	Operation Supervision	546	$ -	$ 719,337	$ -	$ -	$ -	$ -	$ -	$ -
55	Fuel	547	-	-	-	-	-	-	-	-
56	Generation Expenses	548	-	60,549	-	-	-	-	-	-
57	Miscellaneous Other Power Generation Expenses	549	-	225,344	-	-	-	-	-	-
58	Rents	550	-	146	-	-	-	-	-	-
59	Energy Efficiency		-	-	-	-	-	-	-	-
60	Green Building		-	-	-	-	-	-	-	-
61	Solar Rebate		-	-	-	-	-	-	-	-
62										
63										
64	**Maintenance**									
65	Maintenance Supervision and Engineering	551	$ -	$ 21,823	$ -	$ -	$ -	$ -	$ -	$ -
66	Maintenance of Structures	552	-	34,898	-	-	-	-	-	-
67	Maintenance of Generating and Electric Equipment	553	-	2,186,673	-	-	-	-	-	-
68	Maintenance of Misc Other Power Generation Plant	554	-	203,718	-	-	-	-	-	-
69										
70										
71	Other Power Supply									
72	Purchased Power - Recoverable	555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Purchased Power - Non-Recoverable	555	-	-	-	-	-	-	-	-
74	System Control and Load Dispatching - Recoverable	556	-	-	-	-	-	-	-	-
75	System Control and Load Dispatching - Non-Recoverable	556	-	-	-	-	-	-	-	-
76	Other Power Expenses	557	-	-	-	-	-	-	-	-
77										
78										
79	**Total Power Production Expense**									
80										
81	**Transmission Expense**									
82	**Operation**									
83	Operations Supervision and Engineering	560	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84	Load Dispatching	561	-	-	-	-	-	-	-	-
85	Station Expenses	562	-	-	-	-	-	-	-	-
86	Overhead Line Expenses	563	-	-	-	-	-	-	-	-
87	Underground Line Expenses	564	-	-	-	-	-	-	-	-
88	Transmission of Electricity by Others	565	-	-	-	-	-	-	-	-
89	Miscellaneous Transmission Expenses	566	-	-	-	-	-	-	-	-
90	Rents	567	-	-	-	-	-	-	-	-
91										
92										
93	**Maintenance**									
94	Maintenance Supervision and Engineering	568	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
95	Maintenance of Structures	569	-	-	-	-	-	-	-	-
96	Maintenance of Station Equipment	570	-	-	-	-	-	-	-	-
97	Maintenance of Overhead Lines	571	-	-	-	-	-	-	-	-
98	Maintenance of Underground Lines	572	-	-	-	-	-	-	-	-
99	Maintenance of Miscellaneous Transmission Plant	573	-	-	-	-	-	-	-	-
100										
101										

Functional Unbundling
Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Normalize Capital Outlay WP 14	FERC Transition SHEC O&M WP 24	FY 2011 Debt Service WP 5	Net Additional Depreciation WP 2	Transmission COS Off-Set WP 15	Reclassify Prepaid Insurance WP 35	STP Regulatory Asset Deferral WP 33	New Building Lease WP 25
A		B	AD	AE	AF	AG	AH	AI	AJ	AK
102	**Total Transmission Expenses**									
103										
104	**Distribution Expenses**									
105	**Operation**									
106	Operations Supervision and Engineering	580	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
107	Load Dispatching	581	-	-	-	-	-	-	-	-
108	Station Expenses	582	-	-	-	-	-	-	-	-
109	Overhead Line Expenses	583	-	-	-	-	-	-	-	-
110	Underground Line Expenses	584	-	-	-	-	-	-	-	-
111	Street Lighting	585	-	-	-	-	-	-	-	-
112	Meter Expenses	586	-	-	-	-	-	-	-	-
113	Customer Installation Expenses	587	-	-	-	-	-	-	-	-
114	Miscellaneous Distribution Expenses	588	-	-	-	-	-	-	-	-
115	Rents	589	-	-	-	-	-	-	-	-
116										
117										
118	**Maintenance**									
119	Maintenance Supervision and Engineering	590	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
120	Maintenance of Structures	591	-	-	-	-	-	-	-	-
121	Maintenance of Station Equipment	592	-	-	-	-	-	-	-	-
122	Maintenance of Overhead Lines	593	-	-	-	-	-	-	-	-
123	Maintenance of Underground Lines	594	-	-	-	-	-	-	-	-
124	Maintenance of Line Transformers	595	-	-	-	-	-	-	-	-
125	Maintenance of Street Lighting and Signal Systems	596	-	-	-	-	-	-	-	-
126	Maintenance of Meters	597	-	-	-	-	-	-	-	-
127	Maintenance of Miscellaneous Distribution Plant	598	-	-	-	-	-	-	-	-
128										
129										
130	**Total Distribution Expenses**									
131										
132	**Customer and Information Expenses**									
133										
134	Customer Accounts Expenses									
135	Supervision	901	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
136	Meter Reading Expenses	902	-	-	-	-	-	-	-	-
137	Customer Records and Collection Expenses	903	-	-	-	-	-	-	-	-
138	Uncollectible Accounts	904	-	-	-	-	-	-	-	-
139	Miscellaneous Customer Accounts Expenses	905	-	-	-	-	-	-	-	-
140										
141										
142	Cust. Service & Information Expense									
143	Supervision	907	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
144	Customer Assistance Expenses	908	-	-	-	-	-	-	-	-
145	Informational & Instructional Advertising Expenses	909	-	-	-	-	-	-	-	-
146	Misc Customer Service & Informational Expenses	910	-	-	-	-	-	-	-	-
147	Supervision	911	-	-	-	-	-	-	-	-
148	Demonstrating & Selling Expense	912	-	-	-	-	-	-	-	-
149	Advertising Expense	913	-	-	-	-	-	-	-	-
150	Miscellaneous Sales Expense	916	-	-	-	-	-	-	-	-
151										

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Normalize Capital Outlay WP 14	FERC Transition SHEC O&M WP 24	FY 2011 Debt Service WP 5	Net Additional Depreciation WP 2	Transmission COS Off-Set WP 15	Reclassify Prepaid Insurance WP 35	STP Regulatory Asset Deferral WP 33	New Building Lease WP 25
A		B	AD	AE	AF	AG	AH	AI	AJ	AK
152										
153	**Total Customer and Information Expenses**									
154										
155	**General and Administrative Expenses**									
156	Administrative and General Salaries	920	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
157	Office Supplies and Expenses	921	-	-	-	-	-	-	-	-
158	Administrative Expense Transferred	922	-	-	-	-	-	-	-	-
159	Outside Services Employed	923	-	-	-	-	-	-	-	-
160	Property Insurance	924	-	-	-	-	-	2,382,695	-	-
161	Injuries and Damages	925	-	-	-	-	-	(2,382,695)	-	-
162	Employee Pension and Benefits	926	-	-	-	-	-	-	(1,748,752)	-
163	Regulatory Commission Expense	928	-	-	-	-	-	-	-	-
164	General Expenses	930	-	-	-	-	-	-	-	-
165	Rents	931	-	-	-	-	-	-	-	517,778
166	Maintenance of General Plant	935	-	-	-	-	-	-	-	-
167										
168										
169	**Total Operations & Maintenance Expenses**									
170										
171	**Depreciation & Amortization of CIAC**									
172	Depreciation Expense	403	$ -	$ -	$ -	$ 11,842,844	$ -	$ -	$ -	$ -
173	Amortization of CIAC		-	-	-	-	-	-	-	-
174										
175										
176	**Debt Service**		$ -	$ -	$ (4,897,654)	$ -	$ -	$ -	$ -	$ -
177										
178	**General Fund Transfer**	421.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
179										
180	**Margin (as defined below)**									
181										
182	**Sub-Total Revenue Requirement**									
183										
184	**Other Expenses**									
185	Misc Service Revenue	451	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
186	Donations	426	-	-	-	-	-	-	-	-
187	Taxes Other Than Income	408	-	-	-	-	-	-	-	-
188	Expenses - Non-utility operations	417	-	-	-	-	-	-	-	-
189	Franchise Fees		-	-	-	-	-	-	-	-
190										
191										
192	**Other (Non-Rate) Revenue**									
193	Miscellaneous Nonoperating Income	421	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
194	Other Revenue		-	-	-	-	10,066,863	-	-	-
195	Off-System Sales		-	-	-	-	-	-	-	-
196										
197										
198	**Total Revenue Requirement**									
199										
200	**System Retail Sales (MWh)**									
201	Average Rate ($/MWh)									

Functional Unbundling
Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Normalize Capital Outlay WP 14	FERC Transition SHEC O&M WP 24	FY 2011 Debt Service WP 5	Net Additional Depreciation WP 2	Transmission COS Off-Set WP 15	Reclassify Prepaid Insurance WP 35	STP Regulatory Asset Deferral WP 33	New Building Lease WP 25
A		B	AD	AE	AF	AG	AH	AI	AJ	AK
202										
203	**Comparison to Rate Revenue - FY 2009 Rate Structure**									
204	Base Revenue		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
205	Recoverable Fuel									
206	Green Choice		-	-	-	-	-	-	-	-
207	Remove Service Area Street Lighting Fuel Cost		-	-	-	-	-	-	-	-
208										
209										
210										
211	**Over / (Under) Recovery**									
212										
213	*Required Increase / (Decrease) in Rate Revenue*									
214										
215										
216	**Recoverable Fuel Cost**									
217	Fuel	501								
218	Nuclear Fuel Expense	518								
219	Fuel	547								
220	Purchased Power	555								
221	System Control and Load Dispatching	556								
222										
223										
224	**Off-System Sales**									
225										
226	**Net Cost to AE**									
227										
228										
229	**Margin Calculation**									
230	**Cash Sources**									
231	Depreciation Expense	403	$ -	$ -	$ -	$ 11,842,844	$ -	$ -	$ -	$ -
232	Amortization of CIAC		-	-	-	-	-	-	-	-
233	Interest and Dividend Income	419	-	-	-	-	-	-	-	-
234										
235										
236	**Cash Uses**									
237	Capital From Current Revenue		$ (41,579,109)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
238	Required Contributions to Decommissioning Reserves		-	-	-	-	-	-	-	-
239	Required Contributions to Reserves		-	-	-	-	-	-	-	-
240										
241										
242	**Required Margin**									
243										

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Remove Street Lighting Revenue WP 27 & COS	Transmission Expense WP 32	Reclassify Costs Meter Reading WP 31.1	Reserve Fund Contributions WP 29	Metering Expense WP 31	Reclassify Costs as Production WP 36	Reclassify Costs as G&A WP 37	Rate Case Expenses WP 40
A		B	AL	AM	AN	AO	AP	AQ	AR	AS
1	**Power Production Expenses**									
2	Steam Power Generation									
3	**Operation**									
4	Operation Supervision and Engineering	500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Fuel - Recoverable	501	-	-	-	-	-	-	-	-
6	Fuel - Non-Recoverable	501	-	-	-	-	-	-	-	-
7	Steam Expenses	502	-	-	-	-	-	-	-	-
8	Steam from other Sources	503	-	-	-	-	-	-	-	-
9	Steam Transferred	504	-	-	-	-	-	-	-	-
10	Electric Expenses	505	-	-	-	-	-	-	-	-
11	Miscellaneous Steam Expenses	506	-	-	-	-	-	-	-	-
12	Rents	507	-	-	-	-	-	-	-	-
13										
14										
15	**Maintenance**									
16	Maintenance Supervision	510	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Maintenance of Structures	511	-	-	-	-	-	-	-	-
18	Maintenance of Boiler Plant	512	-	-	-	-	-	-	-	-
19	Maintenance of Electric Plant	513	-	-	-	-	-	-	-	-
20	Maintenance of Miscellaneous Steam Plant	514	-	-	-	-	-	-	-	-
21	Rents	515	-	-	-	-	-	-	-	-
22										
23										
24	Nuclear Power Generation									
25	**Operation**									
26	Operation Supervision	517	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Nuclear Fuel Expense	518	-	-	-	-	-	-	-	-
28	Coolants and Water	519	-	-	-	-	-	-	-	-
29	Steam Expenses	520	-	-	-	-	-	-	-	-
30	Electric Expenses	523	-	-	-	-	-	-	-	-
31	Misc Nuclear Power Expenses	524	-	-	-	-	-	-	-	-
32	Rents	525	-	-	-	-	-	-	-	-
33										
34										
35	**Maintenance**									
36	Maintenance Supervision	528	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37	Maintenance of Structures	529	-	-	-	-	-	-	-	-
38	Maintenance of Reactor Plant	530	-	-	-	-	-	-	-	-
39	Maintenance of Electric Plant	531	-	-	-	-	-	-	-	-
40	Maintenance of Miscellaneous	532	-	-	-	-	-	-	-	-
41										
42										
43	Hydraulic Power Generation									
44	**Maintenance**									
45	Maintenance Supervision	541	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Maintenance of Structures	542	-	-	-	-	-	-	-	-
47	Maintenance of Reservoirs, Dams & Waterways	543	-	-	-	-	-	-	-	-
48	Maintenance of Electric Plant	544	-	-	-	-	-	-	-	-
49	Maintenance of Miscellaneous Hydraulic Plant	545	-	-	-	-	-	-	-	-
50										
51										

Functional Unbundling
Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Remove Street Lighting Revenue WP 27 & COS	Transmission Expense WP 32	Reclassify Costs Meter Reading WP 31.1	Reserve Fund Contributions WP 29	Metering Expense WP 31	Reclassify Costs as Production WP 36	Reclassify Costs as G&A WP 37	Rate Case Expenses WP 40
A		B	AL	AM	AN	AO	AP	AQ	AR	AS
52	Other Power Generation									
53	**Operation**									
54	Operation Supervision	546	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	Fuel	547	-	-	-	-	-	-	-	-
56	Generation Expenses	548	-	-	-	-	-	-	-	-
57	Miscellaneous Other Power Generation Expenses	549	-	-	-	-	-	-	-	-
58	Rents	550	-	-	-	-	-	-	-	-
59	Energy Efficiency		-	-	-	-	-	21,485,378	-	-
60	Green Building		-	-	-	-	-	1,881,981	-	-
61	Solar Rebate		-	-	-	-	-	4,352,770	-	-
62										
63										
64	**Maintenance**									
65	Maintenance Supervision and Engineering	551	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	Maintenance of Structures	552	-	-	-	-	-	-	-	-
67	Maintenance of Generating and Electric Equipment	553	-	-	-	-	-	-	-	-
68	Maintenance of Misc Other Power Generation Plant	554	-	-	-	-	-	-	-	-
69										
70										
71	Other Power Supply									
72	Purchased Power - Recoverable	555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Purchased Power - Non-Recoverable	555	-	-	-	-	-	-	-	-
74	System Control and Load Dispatching - Recoverable	556	-	-	-	-	-	-	-	-
75	System Control and Load Dispatching - Non-Recoverable	556	-	-	-	-	-	-	-	-
76	Other Power Expenses	557	-	-	-	-	-	-	-	-
77										
78										
79	**Total Power Production Expense**									
80										
81	**Transmission Expense**									
82	**Operation**									
83	Operations Supervision and Engineering	560	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84	Load Dispatching	561	-	-	-	-	-	-	-	-
85	Station Expenses	562	-	-	-	-	-	-	-	-
86	Overhead Line Expenses	563	-	-	-	-	-	-	-	-
87	Underground Line Expenses	564	-	-	-	-	-	-	-	-
88	Transmission of Electricity by Others	565	-	7,437,633	-	-	-	-	-	-
89	Miscellaneous Transmission Expenses	566	-	-	-	-	-	-	-	-
90	Rents	567	-	-	-	-	-	-	-	-
91										
92										
93	**Maintenance**									
94	Maintenance Supervision and Engineering	568	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
95	Maintenance of Structures	569	-	-	-	-	-	-	-	-
96	Maintenance of Station Equipment	570	-	-	-	-	-	-	-	-
97	Maintenance of Overhead Lines	571	-	-	-	-	-	-	-	-
98	Maintenance of Underground Lines	572	-	-	-	-	-	-	-	-
99	Maintenance of Miscellaneous Transmission Plant	573	-	-	-	-	-	-	-	-
100										
101										

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Remove Street Lighting Revenue WP 27 & COS	Transmission Expense WP 32	Reclassify Costs Meter Reading WP 31.1	Reserve Fund Contributions WP 29	Metering Expense WP 31	Reclassify Costs as Production WP 36	Reclassify Costs as G&A WP 37	Rate Case Expenses WP 40
A		B	AL	AM	AN	AO	AP	AQ	AR	AS
102	**Total Transmission Expenses**									
103										
104	**Distribution Expenses**									
105	**Operation**									
106	Operations Supervision and Engineering	580	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
107	Load Dispatching	581	-	-	-	-	-	-	-	-
108	Station Expenses	582	-	-	-	-	-	-	-	-
109	Overhead Line Expenses	583	-	-	-	-	-	-	-	-
110	Underground Line Expenses	584	-	-	-	-	-	-	-	-
111	Street Lighting	585	-	-	-	-	-	-	-	-
112	Meter Expenses	586	-	-	(1,131,023)	-	-	-	-	-
113	Customer Installation Expenses	587	-	-	-	-	-	-	-	-
114	Miscellaneous Distribution Expenses	588	-	-	-	-	-	-	-	-
115	Rents	589	-	-	-	-	-	-	-	-
116										
117										
118	**Maintenance**									
119	Maintenance Supervision and Engineering	590	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
120	Maintenance of Structures	591	-	-	-	-	-	-	-	-
121	Maintenance of Station Equipment	592	-	-	-	-	-	-	-	-
122	Maintenance of Overhead Lines	593	-	-	-	-	-	-	-	-
123	Maintenance of Underground Lines	594	-	-	-	-	-	-	-	-
124	Maintenance of Line Transformers	595	-	-	-	-	-	-	-	-
125	Maintenance of Street Lighting and Signal Systems	596	-	-	-	-	-	-	-	-
126	Maintenance of Meters	597	-	-	-	-	-	-	-	-
127	Maintenance of Miscellaneous Distribution Plant	598	-	-	-	-	-	-	-	-
128										
129										
130	**Total Distribution Expenses**									
131										
132	**Customer and Information Expenses**									
133										
134	Customer Accounts Expenses									
135	Supervision	901	$ -	$ -	$ -	$ -	$ -	$ (120,934)	$ (224)	$ -
136	Meter Reading Expenses	902	-	-	1,131,023	-	2,047,526	(36,647)	(35,492)	-
137	Customer Records and Collection Expenses	903	-	-	-	-	-	-	(147,206)	-
138	Uncollectible Accounts	904	-	-	-	-	-	-	-	-
139	Miscellaneous Customer Accounts Expenses	905	-	-	-	-	-	-	262,951	-
140										
141										
142	Cust. Service & Information Expense									
143	Supervision	907	$ -	$ -	$ -	$ -	$ -	$ (3,371,961)	$ 190,821	$ -
144	Customer Assistance Expenses	908	-	-	-	-	-	(22,844,137)	(65,397)	-
145	Informational & Instructional Advertising Expenses	909	-	-	-	-	-	(893,792)	(40,210)	-
146	Misc Customer Service & Informational Expenses	910	-	-	-	-	-	(434,331)	(10,522)	-
147	Supervision	911	-	-	-	-	-	-	(62,438)	-
148	Demonstrating & Selling Expense	912	-	-	-	-	-	(13,690)	(2,027)	-
149	Advertising Expense	913	-	-	-	-	-	4,473	-	-
150	Miscellaneous Sales Expense	916	-	-	-	-	-	(9,110)	(4,585)	-
151										

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Remove Street Lighting Revenue WP 27 & COS	Transmission Expense WP 32	Reclassify Costs Meter Reading WP 31.1	Reserve Fund Contributions WP 29	Metering Expense WP 31	Reclassify Costs as Production WP 36	Reclassify Costs as G&A WP 37	Rate Case Expenses WP 40
A		B	AL	AM	AN	AO	AP	AQ	AR	AS
152										
153	**Total Customer and Information Expenses**									
154										
155	**General and Administrative Expenses**									
156	Administrative and General Salaries	920	$ -	$ -	$ -	$ -	$ -	$ -	$ 322,862	$ -
157	Office Supplies and Expenses	921	-	-	-	-	-	-	-	-
158	Administrative Expense Transferred	922	-	-	-	-	-	-	-	-
159	Outside Services Employed	923	-	-	-	-	-	-	-	-
160	Property Insurance	924	-	-	-	-	-	-	-	-
161	Injuries and Damages	925	-	-	-	-	-	-	-	-
162	Employee Pension and Benefits	926	-	-	-	-	-	-	-	-
163	Regulatory Commission Expense	928	-	-	-	-	-	-	-	1,292,907
164	General Expenses	930	-	-	-	-	-	-	(408,533)	-
165	Rents	931	-	-	-	-	-	-	-	-
166	Maintenance of General Plant	935	-	-	-	-	-	-	-	-
167										
168										
169	**Total Operations & Maintenance Expenses**									
170										
171	**Depreciation & Amortization of CIAC**									
172	Depreciation Expense	403	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
173	Amortization of CIAC		-	-	-	-	-	-	-	-
174										
175										
176	**Debt Service**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
177										
178	**General Fund Transfer**	421.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
179										
180	**Margin (as defined below)**									
181										
182	**Sub-Total Revenue Requirement**									
183										
184	**Other Expenses**									
185	Misc Service Revenue	451	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
186	Donations	426	-	-	-	-	-	-	-	-
187	Taxes Other Than Income	408	-	-	-	-	-	-	-	-
188	Expenses - Non-utility operations	417	-	-	-	-	-	-	-	-
189	Franchise Fees		-	-	-	-	-	-	-	-
190										
191										
192	**Other (Non-Rate) Revenue**									
193	Miscellaneous Nonoperating Income	421	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
194	Other Revenue		-	-	-	-	-	-	-	-
195	Off-System Sales		-	-	-	-	-	-	-	-
196										
197										
198	**Total Revenue Requirement**									
199										
200	**System Retail Sales (MWh)**									
201	Average Rate ($/MWh)									

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Remove Street Lighting Revenue WP 27 & COS	Transmission Expense WP 32	Reclassify Costs Meter Reading WP 31.1	Reserve Fund Contributions WP 29	Metering Expense WP 31	Reclassify Costs as Production WP 36	Reclassify Costs as G&A WP 37	Rate Case Expenses WP 40
A		B	AL	AM	AN	AO	AP	AQ	AR	AS
202										
203	**Comparison to Rate Revenue - FY 2009 Rate Structure**									
204	Base Revenue		$ (4,744,155)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
205	Recoverable Fuel									
206	Green Choice		-	-	-	-	-	-	-	-
207	Remove Service Area Street Lighting Fuel Cost		(1,077,588)	-	-	-	-	-	-	-
208										
209										
210										
211	**Over / (Under) Recovery**									
212										
213	*Required Increase / (Decrease) in Rate Revenue*									
214										
215										
216	**Recoverable Fuel Cost**									
217	Fuel	501								
218	Nuclear Fuel Expense	518								
219	Fuel	547								
220	Purchased Power	555								
221	System Control and Load Dispatching	556								
222										
223										
224	**Off-System Sales**									
225										
226	**Net Cost to AE**									
227										
228										
229	**Margin Calculation**									
230	**Cash Sources**									
231	Depreciation Expense	403	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
232	Amortization of CIAC		-	-	-	-	-	-	-	-
233	Interest and Dividend Income	419	-	-	-	-	-	-	-	-
234										
235										
236	**Cash Uses**									
237	Capital From Current Revenue		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
238	Required Contributions to Decommissioning Reserves		-	-	-	6,716,995	-	-	-	-
239	Required Contributions to Reserves		-	-	-	15,960,533	-	-	-	-
240										
241										
242	**Required Margin**									
243										

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Update Other Revenue WP 15	Indirect Overhead Redistribution WP 45	Remove Non-Electric Indirect WP 45	Remove Holly Non-Labor O&M WP 24.1
A		B	AT	AU	AV	AW
1	**Power Production Expenses**					
2	Steam Power Generation					
3	**Operation**					
4	Operation Supervision and Engineering	500	$ -	$ 172,794	$ -	$ (39,352)
5	Fuel - Recoverable	501	-	-	-	-
6	Fuel - Non-Recoverable	501	-	-	-	(6,506)
7	Steam Expenses	502	-	-	-	(739)
8	Steam from other Sources	503	-	-	-	-
9	Steam Transferred	504	-	-	-	-
10	Electric Expenses	505	-	-	-	-
11	Miscellaneous Steam Expenses	506	-	3,505	-	(45,815)
12	Rents	507	-	-	-	-
13						
14						
15	**Maintenance**					
16	Maintenance Supervision	510	$ -	$ 3,960	$ -	$ (8,992)
17	Maintenance of Structures	511	-	-	-	(236)
18	Maintenance of Boiler Plant	512	-	-	-	(2,194)
19	Maintenance of Electric Plant	513	-	4,041	-	(18,333)
20	Maintenance of Miscellaneous Steam Plant	514	-	1,726	-	(55,896)
21	Rents	515	-	-	-	-
22						
23						
24	Nuclear Power Generation					
25	**Operation**					
26	Operation Supervision	517	$ -	$ -	$ -	$ -
27	Nuclear Fuel Expense	518	-	-	-	-
28	Coolants and Water	519	-	-	-	-
29	Steam Expenses	520	-	-	-	-
30	Electric Expenses	523	-	-	-	-
31	Misc Nuclear Power Expenses	524	-	-	-	-
32	Rents	525	-	-	-	-
33						
34						
35	**Maintenance**					
36	Maintenance Supervision	528	$ -	$ -	$ -	$ -
37	Maintenance of Structures	529	-	-	-	-
38	Maintenance of Reactor Plant	530	-	-	-	-
39	Maintenance of Electric Plant	531	-	-	-	-
40	Maintenance of Miscellaneous	532	-	-	-	-
41						
42						
43	Hydraulic Power Generation					
44	**Maintenance**					
45	Maintenance Supervision	541	$ -	$ -	$ -	$ -
46	Maintenance of Structures	542	-	-	-	-
47	Maintenance of Reservoirs, Dams & Waterways	543	-	-	-	-
48	Maintenance of Electric Plant	544	-	-	-	-
49	Maintenance of Miscellaneous Hydraulic Plant	545	-	-	-	-
50						
51						

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Update Other Revenue WP 15	Indirect Overhead Redistribution WP 45	Remove Non-Electric Indirect WP 45	Remove Holly Non-Labor O&M WP 24.1
A		B	AT	AU	AV	AW
52	Other Power Generation					
53	**Operation**					
54	Operation Supervision	546	$ -	$ 4,059	$ -	$ -
55	Fuel	547	-	-	-	-
56	Generation Expenses	548	-	-	-	-
57	Miscellaneous Other Power Generation Expenses	549	-	233	-	-
58	Rents	550	-	-	-	-
59	Energy Efficiency		-	-	-	-
60	Green Building		-	-	-	-
61	Solar Rebate		-	-	-	-
62						
63						
64	**Maintenance**					
65	Maintenance Supervision and Engineering	551	$ -	$ 168	$ -	$ -
66	Maintenance of Structures	552	-	-	-	-
67	Maintenance of Generating and Electric Equipment	553	-	91,421	-	-
68	Maintenance of Misc Other Power Generation Plant	554	-	46,071	-	-
69						
70						
71	Other Power Supply					
72	Purchased Power - Recoverable	555	$ -	$ -	$ -	$ -
73	Purchased Power - Non-Recoverable	555	-	-	-	-
74	System Control and Load Dispatching - Recoverable	556	-	-	-	-
75	System Control and Load Dispatching - Non-Recoverable	556	-	-	-	-
76	Other Power Expenses	557	-	-	-	-
77						
78						
79	**Total Power Production Expense**					
80						
81	**Transmission Expense**					
82	**Operation**					
83	Operations Supervision and Engineering	560	$ -	$ 1,241,230	$ -	$ -
84	Load Dispatching	561	-	104	-	-
85	Station Expenses	562	-	196,229	-	-
86	Overhead Line Expenses	563	-	795,525	-	-
87	Underground Line Expenses	564	-	189	-	-
88	Transmission of Electricity by Others	565	-	-	-	-
89	Miscellaneous Transmission Expenses	566	-	3,221	-	-
90	Rents	567	-	-	-	-
91						
92						
93	**Maintenance**					
94	Maintenance Supervision and Engineering	568	$ -	$ 728	$ -	$ -
95	Maintenance of Structures	569	-	8,037	-	-
96	Maintenance of Station Equipment	570	-	1,193,453	-	-
97	Maintenance of Overhead Lines	571	-	-	-	-
98	Maintenance of Underground Lines	572	-	-	-	-
99	Maintenance of Miscellaneous Transmission Plant	573	-	-	-	-
100						
101						

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Update Other Revenue WP 15	Indirect Overhead Redistribution WP 45	Remove Non-Electric Indirect WP 45	Remove Holly Non-Labor O&M WP 24.1
A		B	AT	AU	AV	AW
102	**Total Transmission Expenses**					
103						
104	**Distribution Expenses**					
105	**Operation**					
106	Operations Supervision and Engineering	580	$ -	$ 380,979	$ -	$ -
107	Load Dispatching	581	-	36,274	-	-
108	Station Expenses	582	-	18,616	-	-
109	Overhead Line Expenses	583	-	4,736,458	-	-
110	Underground Line Expenses	584	-	3,527,972	-	-
111	Street Lighting	585	-	341,312	-	-
112	Meter Expenses	586	-	346,718	-	-
113	Customer Installation Expenses	587	-	-	-	-
114	Miscellaneous Distribution Expenses	588	-	820,639	-	-
115	Rents	589	-	507	-	-
116						
117						
118	**Maintenance**					
119	Maintenance Supervision and Engineering	590	$ -	$ -	$ -	$ -
120	Maintenance of Structures	591	-	-	-	-
121	Maintenance of Station Equipment	592	-	199,763	-	-
122	Maintenance of Overhead Lines	593	-	115,959	-	-
123	Maintenance of Underground Lines	594	-	41,921	-	-
124	Maintenance of Line Transformers	595	-	611	-	-
125	Maintenance of Street Lighting and Signal Systems	596	-	724	-	-
126	Maintenance of Meters	597	-	-	-	-
127	Maintenance of Miscellaneous Distribution Plant	598	-	30,135	-	-
128						
129						
130	**Total Distribution Expenses**					
131						
132	**Customer and Information Expenses**					
133						
134	Customer Accounts Expenses					
135	Supervision	901	$ -	$ -	$ -	$ -
136	Meter Reading Expenses	902	-	-	-	-
137	Customer Records and Collection Expenses	903	-	-	-	-
138	Uncollectible Accounts	904	-	-	-	-
139	Miscellaneous Customer Accounts Expenses	905	-	-	-	-
140						
141						
142	Cust. Service & Information Expense					
143	Supervision	907	$ -	$ 1,536	$ -	$ -
144	Customer Assistance Expenses	908	-	337	-	-
145	Informational & Instructional Advertising Expenses	909	-	-	-	-
146	Misc Customer Service & Informational Expenses	910	-	-	-	-
147	Supervision	911	-	-	-	-
148	Demonstrating & Selling Expense	912	-	-	-	-
149	Advertising Expense	913	-	-	-	-
150	Miscellaneous Sales Expense	916	-	-	-	-
151						

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Update Other Revenue WP 15	Indirect Overhead Redistribution WP 45	Remove Non-Electric Indirect WP 45	Remove Holly Non-Labor O&M WP 24.1
A		B	AT	AU	AV	AW
152						
153	**Total Customer and Information Expenses**					
154						
155	**General and Administrative Expenses**					
156	Administrative and General Salaries	920	$ -	$ (14,528,717)	$ -	$ -
157	Office Supplies and Expenses	921	-	-	-	-
158	Administrative Expense Transferred	922	-	-	-	-
159	Outside Services Employed	923	-	-	-	-
160	Property Insurance	924	-	-	-	-
161	Injuries and Damages	925	-	-	-	-
162	Employee Pension and Benefits	926	-	-	-	-
163	Regulatory Commission Expense	928	-	-	-	-
164	General Expenses	930	-	35,786	-	-
165	Rents	931	-	-	-	-
166	Maintenance of General Plant	935	-	100	-	-
167						
168						
169	**Total Operations & Maintenance Expenses**					
170						
171	**Depreciation & Amortization of CIAC**					
172	Depreciation Expense	403	$ -	$ -	$ -	$ -
173	Amortization of CIAC		-	-	-	-
174						
175						
176	**Debt Service**		$ -	$ -	$ -	$ -
177						
178	**General Fund Transfer**	421.5	$ -	$ -	$ -	$ -
179						
180	**Margin (as defined below)**					
181						
182	**Sub-Total Revenue Requirement**					
183						
184	**Other Expenses**					
185	Misc Service Revenue	451	$ -	$ -	$ -	$ -
186	Donations	426	-	-	-	-
187	Taxes Other Than Income	408	-	-	-	-
188	Expenses - Non-utility operations	417	-	125,676	(125,676)	-
189	Franchise Fees		-	-	-	-
190						
191						
192	**Other (Non-Rate) Revenue**					
193	Miscellaneous Nonoperating Income	421	$ -	$ -	$ -	$ -
194	Other Revenue		(19,807)	-	-	-
195	Off-System Sales		-	-	-	-
196						
197						
198	**Total Revenue Requirement**					
199						
200	**System Retail Sales (MWh)**					
201	Average Rate ($/MWh)					

Functional Unbundling

Purpose: Develop the Functionalized Test Year Revenue Requirement

Line No.		FERC Account	Update Other Revenue WP 15	Indirect Overhead Redistribution WP 45	Remove Non-Electric Indirect WP 45	Remove Holly Non-Labor O&M WP 24.1
A		B	AT	AU	AV	AW
202						
203	**Comparison to Rate Revenue - FY 2009 Rate Structure**					
204	Base Revenue		$ -	$ -	$ -	$ -
205	Recoverable Fuel					
206	Green Choice		-	-	-	-
207	Remove Service Area Street Lighting Fuel Cost		-	-	-	-
208						
209						
210						
211	**Over / (Under) Recovery**					
212						
213	*Required Increase / (Decrease) in Rate Revenue*					
214						
215						
216	**Recoverable Fuel Cost**					
217	Fuel	501				
218	Nuclear Fuel Expense	518				
219	Fuel	547				
220	Purchased Power	555				
221	System Control and Load Dispatching	556				
222						
223						
224	**Off-System Sales**					
225						
226	**Net Cost to AE**					
227						
228						
229	**Margin Calculation**					
230	**Cash Sources**					
231	Depreciation Expense	403	$ -	$ -	$ -	$ -
232	Amortization of CIAC		-	-	-	-
233	Interest and Dividend Income	419	-	-	-	-
234						
235						
236	**Cash Uses**					
237	Capital From Current Revenue		$ -	$ -	$ -	$ -
238	Required Contributions to Decommissioning Reserves		-	-	-	-
239	Required Contributions to Reserves		-	-	-	-
240						
241						
242	**Required Margin**					
243						

Test Year Revenue Requirement - Production
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related Base Load Nuclear	Base Load Coal	Intermediate Gas	Peak Gas	Renewable Solar
A		B	C	D	E	F	G	H	I	J
1	**Power Production Expenses**									
2	Steam Power Generation									
3	**Operation**									
4	Operation Supervision and Engineering	500	Functional Unbundling	$ 7,911,687	FERC 500	$ -	$ 3,405,387	$ 4,506,300	$ -	$ -
5	Fuel - Recoverable	501	Functional Unbundling	131,529,489	Steam Fuel	-	-	-	-	-
6	Fuel - Non-Recoverable	501	Functional Unbundling	4,944,942	501 Non-Recoverable	-	4,118,710	826,231	-	-
7	Steam Expenses	502	Functional Unbundling	6,346,996	FERC 502	-	5,582,916	764,080	-	-
8	Steam from other Sources	503	Functional Unbundling	-		-	-	-	-	-
9	Steam Transferred	504	Functional Unbundling	-		-	-	-	-	-
10	Electric Expenses	505	Functional Unbundling	1,700,950	FERC 505	-	1,663,343	37,607	-	-
11	Miscellaneous Steam Expenses	506	Functional Unbundling	4,199,234	FERC 506	-	3,191,382	1,007,852	-	-
12	Rents	507	Functional Unbundling	-		-	-	-	-	-
13				$ 156,633,297		$ -	$ 17,961,739	$ 7,142,070	$ -	$ -
14										
15	**Maintenance**									
16	Maintenance Supervision	510	Functional Unbundling	$ 2,456,738	FERC 510	$ -	$ 1,327,460	$ 1,129,278	$ -	$ -
17	Maintenance of Structures	511	Functional Unbundling	227,254	FERC 511	-	150,668	76,586	-	-
18	Maintenance of Boiler Plant	512	Functional Unbundling	5,798,568	FERC 512	-	4,613,321	1,185,247	-	-
19	Maintenance of Electric Plant	513	Functional Unbundling	3,022,679	FERC 513	-	2,632,193	390,487	-	-
20	Maintenance of Miscellaneous Steam Plant	514	Functional Unbundling	3,655,717	FERC 514	-	1,710,771	1,944,946	-	-
21	Rents	515	Functional Unbundling	-		-	-	-	-	-
22				$ 15,160,958		$ -	$ 10,434,413	$ 4,726,544	$ -	$ -
23										
24	Nuclear Power Generation									
25	**Operation**									
26	Operation Supervision	517	Functional Unbundling	$ 8,927,390	Nuclear DA	$ 8,927,390	$ -	$ -	$ -	$ -
27	Nuclear Fuel Expense	518	Functional Unbundling	19,347,060	Nuclear Fuel	-	-	-	-	-
28	Coolants and Water	519	Functional Unbundling	1,037,009	Nuclear DA	1,037,009	-	-	-	-
29	Steam Expenses	520	Functional Unbundling	1,960,827	Nuclear DA	1,960,827	-	-	-	-
30	Electric Expenses	523	Functional Unbundling	4,325,651	Nuclear DA	4,325,651	-	-	-	-
31	Misc Nuclear Power Expenses	524	Functional Unbundling	13,103,665	Nuclear DA	13,103,665	-	-	-	-
32	Rents	525	Functional Unbundling	-	Nuclear DA	-	-	-	-	-
33				$ 48,701,602		$ 29,354,542	$ -	$ -	$ -	$ -
34										
35	**Maintenance**									
36	Maintenance Supervision	528	Functional Unbundling	$ 6,051,042	Nuclear DA	$ 6,051,042	$ -	$ -	$ -	$ -
37	Maintenance of Structures	529	Functional Unbundling	2,688,726	Nuclear DA	2,688,726	-	-	-	-
38	Maintenance of Reactor Plant	530	Functional Unbundling	7,144,179	Nuclear DA	7,144,179	-	-	-	-
39	Maintenance of Electric Plant	531	Functional Unbundling	3,565,883	Nuclear DA	3,565,883	-	-	-	-
40	Maintenance of Miscellaneous	532	Functional Unbundling	748,640	Nuclear DA	748,640	-	-	-	-
41				$ 20,198,469		$ 20,198,469	$ -	$ -	$ -	$ -
42										
43	Hydraulic Power Generation									
44	**Maintenance**									
45	Maintenance Supervision	541	Functional Unbundling	$ -		$ -	$ -	$ -	$ -	$ -
46	Maintenance of Structures	542	Functional Unbundling	-		-	-	-	-	-
47	Maintenance of Reservoirs, Dams & Waterways	543	Functional Unbundling	-		-	-	-	-	-
48	Maintenance of Electric Plant	544	Functional Unbundling	-		-	-	-	-	-
49	Maintenance of Miscellaneous Hydraulic Plant	545	Functional Unbundling	-		-	-	-	-	-
50				$ -		$ -	$ -	$ -	$ -	$ -
51										
52	Other Power Generation									
53	**Operation**									
54	Operation Supervision	546	Functional Unbundling	$ 2,500,579	FERC 546	$ -	$ -	$ 2,120,230	$ 380,349	$ -
55	Fuel	547	Functional Unbundling	122,429,167	Other Fuel	-	-	-	-	-
56	Generation Expenses	548	Functional Unbundling	4,057,389	FERC 548	-	-	3,508,609	548,779	-
57	Miscellaneous Other Power Generation Expenses	549	Functional Unbundling	333,592	FERC 549	-	-	236,664	96,928	-

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

						Demand Related				
Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Base Load Nuclear	Base Load Coal	Intermediate Gas	Peak Gas	Renewable Solar
A		B	C	D	E	F	G	H	I	J
58	Rents	550	Functional Unbundling	205,206	FERC 550	-	-	117,554	87,651	-
59	Energy Efficiency		Functional Unbundling	21,485,378	Community Benefit	-	-	-	-	-
60	Green Building		Functional Unbundling	1,881,981	Community Benefit	-	-	-	-	-
61	Solar Rebate		Functional Unbundling	4,352,770	Community Benefit	-	-	-	-	-
62				$ 157,246,061		$ -	$ -	$ 5,983,057	$ 1,113,708	$ -
63										
64	**Maintenance**									
65	Maintenance Supervision and Engineering	551	Functional Unbundling	$ 43,213	FERC 551	$ -	$ -	$ 38,978	$ 4,235	$ -
66	Maintenance of Structures	552	Functional Unbundling	147,578	FERC 552	-	-	108,444	39,134	-
67	Maintenance of Generating and Electric Equipment	553	Functional Unbundling	13,253,125	FERC 553	-	-	11,136,167	2,116,958	-
68	Maintenance of Misc Other Power Generation Plant	554	Functional Unbundling	1,443,910	FERC 554	-	-	1,230,913	212,997	-
69				$ 14,887,826		$ -	$ -	$ 12,514,502	$ 2,373,324	$ -
70										
71	Other Power Supply									
72	Purchased Power - Recoverable	555	Functional Unbundling	$ 96,511,902	555 Recoverable	$ -	$ -	$ -	$ -	$ -
73	Purchased Power - Non-Recoverable	555	Functional Unbundling	10,403,215	555 Non-Recoverable	-	-	-	-	-
74	System Control and Load Dispatching - Recoverable	556	Functional Unbundling	21,079,958	556 Recoverable	-	-	-	-	-
75	System Control and Load Dispatching - Non-Recoverable	556	Functional Unbundling	1,802,970	556 Non-Recoverable	951,607	419,545	318,975	70,432	42,410
76	Other Power Expenses	557	Functional Unbundling	489,793	Prod RR - Demand	258,513	113,973	86,652	19,134	11,521
77				$ 130,287,838		$ 1,210,120	$ 533,518	$ 405,627	$ 89,566	$ 53,932
78										
79	**Total Power Production Expense**			**$ 543,116,051**		**$ 50,763,131**	**$ 28,929,670**	**$ 30,771,801**	**$ 3,576,599**	**$ 53,932**
80										
101										
102	**Total Transmission Expenses**			**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
103										
129										
130	**Total Distribution Expenses**			**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
131										
132	**Customer and Information Expenses**									
151				$ -		$ -	$ -	$ -	$ -	$ -
152										
153	**Total Customer and Information Expenses**			**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
154										
155	**General and Administrative Expenses**									
156	Administrative and General Salaries	920	Functional Unbundling	$ 8,849,743	Prod 920	$ 2,363,448	$ 2,635,607	$ 3,522,116	$ 312,493	$ 16,080
157	Office Supplies and Expenses	921	Functional Unbundling	5,273,986	Prod 921	794,512	1,820,165	2,432,394	215,810	11,105
158	Administrative Expense Transferred	922	Functional Unbundling	11,300	Prod 920	3,018	3,365	4,497	399	21
159	Outside Services Employed	923	Functional Unbundling	5,754,009	Prod 923	3,400,362	1,075,132	1,143,592	132,919	2,004
160	Property Insurance	924	Functional Unbundling	2,258,015	Prod 924	1,085,099	665,414	269,512	234,590	3,359
161	Injuries and Damages	925	Functional Unbundling	1,097,461	Prod 925	422,460	348,961	298,220	26,459	1,361
162	Employee Pension and Benefits	926	Functional Unbundling	9,931,952	Prod 926	6,550,387	3,303,013	71,849	6,375	328
163	Regulatory Commission Expense	928	Functional Unbundling	670,167	Prod RR	155,518	68,565	52,129	11,510	6,931
164	General Expenses	930	Functional Unbundling	6,524,359	Prod 930	1,055,389	2,857,779	2,388,383	211,905	10,904
165	Rents	931	Functional Unbundling	562,234	Prod 931	36,503	213,623	285,477	25,328	1,303
166	Maintenance of General Plant	935	Functional Unbundling	895,159	Prod 935	883,305	5,150	3,560	3,099	44
167				$ 41,828,385		$ 16,750,000	$ 12,996,775	$ 10,471,728	$ 1,180,887	$ 53,441
168										
169	**Total Operations & Maintenance Expenses**			**$ 584,944,436**		**$ 67,513,130**	**$ 41,926,445**	**$ 41,243,529**	**$ 4,757,486**	**$ 107,372**
170										
171	**Depreciation & Amortization of CIAC**									
172	Depreciation Expense	403	Functional Unbundling	$ 60,991,236	T Prod Plant - Depr	$ 25,111,141	$ 16,353,491	$ 12,402,022	$ 7,010,998	$ 112,323
173	Amortization of CIAC		Functional Unbundling	-	T Prod Plant - Depr	-	-	-	-	-
174				**$ 60,991,236**		**$ 25,111,141**	**$ 16,353,491**	**$ 12,402,022**	**$ 7,010,998**	**$ 112,323**
175										
176	**Debt Service**		Functional Unbundling	**$ 88,022,271**	Prod Debt Service	**$ 67,717,112**	**$ 12,813,471**	**$ 403,517**	**$ 238,516**	**$ 6,849,656**

Test Year Revenue Requirement - Production
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related Base Load Nuclear	Demand Related Base Load Coal	Demand Related Intermediate Gas	Demand Related Peak Gas	Demand Related Renewable Solar
A		B	C	D	E	F	G	H	I	J
177										
178	**General Fund Transfer**	421.5	Functional Unbundling	**$ 72,762,791**	Prod RR	**$ 16,885,211**	**$ 7,444,363**	**$ 5,659,859**	**$ 1,249,742**	**$ 752,527**
179										
180	**Margin**		Functional Unbundling	**$ (4,641,370)**	T Prod Plant - Depr	**$ (1,910,932)**	**$ (1,244,484)**	**$ (943,781)**	**$ (533,530)**	**$ (8,548)**
181										
182	**Sub-Total Revenue Requirement**			**$ 802,079,364**		**$ 175,315,661**	**$ 77,293,286**	**$ 58,765,145**	**$ 12,723,213**	**$ 7,813,330**
183										
184	**Other Expenses**									
185	Misc Service Revenue	451	Functional Unbundling	$ 29,409	Prod RR - Demand	$ 15,522	$ 6,843	$ 5,203	$ 1,149	$ 692
186	Donations	426	Functional Unbundling	41,353	Prod RR - Demand	21,826	9,623	7,316	1,615	973
187	Taxes Other Than Income	408	Functional Unbundling	18,736	Prod RR - Demand	9,889	4,360	3,315	732	441
188	Expenses - Non-utility operations	417	Functional Unbundling	252,602	Peak Gas DA	-	-	-	252,602	-
189	Franchise Fees		Functional Unbundling	-	Prod RR - Demand	-	-	-	-	-
190				**$ 342,100**		**$ 47,237**	**$ 20,826**	**$ 15,834**	**$ 256,098**	**$ 2,105**
191										
192	**Other (Non-Rate) Revenue**									
193	Miscellaneous Nonoperating Income	421	Functional Unbundling	$ 2,684	Prod RR - Demand	$ 1,416	$ 624	$ 475	$ 105	$ 63
194	Other Revenue		Functional Unbundling	687,951	Prod RR - Demand	363,100	160,084	121,710	26,874	16,182
195	Off-System Sales		Functional Unbundling	-	Prod RR - Demand	-	-	-	-	-
196				**$ 690,634**		**$ 364,517**	**$ 160,708**	**$ 122,185**	**$ 26,979**	**$ 16,245**
197										
198	**Total Revenue Requirement**			**$ 801,730,829**		**$ 174,998,382**	**$ 77,153,403**	**$ 58,658,794**	**$ 12,952,332**	**$ 7,799,190**
199										
200	**System Retail Sales (MWH)**		Functional Unbundling	11,813,939						
201	Average Rate ($/MWh)			$ 67.86						
202										
203										
204										
205	**Gross Plant In Service**									
212										
213	Steam Power Generation									
214	Land & Land Rights	310	WP 2	$ 9,234,828	Steam Plant - G	$ -	$ 6,937,079	$ 2,297,749	$ -	$ -
215	Structures & Improvements	311	WP 2	89,448,743	Steam Plant - G	-	67,192,697	22,256,046	-	-
216	Boiler Plant Equipment	312	WP 2	411,835,651	Steam Plant - G	-	309,365,421	102,470,231	-	-
217	Engines and Engine Driven Generators	313	WP 2	-	Steam Plant - G	-	-	-	-	-
218	Turbogenerator Units	314	WP 2	75,657,814	Steam Plant - G	-	56,833,136	18,824,678	-	-
219	Accessory Plt Equipment	315	WP 2	30,715,062	Steam Plant - G	-	23,072,743	7,642,319	-	-
220	Miscellaneous Equipment	316	WP 2	62,763,111	Steam Plant - G	-	47,146,808	15,616,303	-	-
221				$ 679,655,210		$ -	$ 510,547,883	$ 169,107,327	$ -	$ -
222										
223	Nuclear Power Generation									
224	Land & Land Rights	320	WP 2	$ 2,782,002	Nuclear DA	$ 2,782,002	$ -	$ -	$ -	$ -
225	Structures & Improvements	321	WP 2	406,719,894	Nuclear DA	406,719,894	-	-	-	-
226	Reactor Plant Equipment	322	WP 2	293,509,807	Nuclear DA	293,509,807	-	-	-	-
227	Turbogenerator Units	323	WP 2	48,391,775	Nuclear DA	48,391,775	-	-	-	-
228	Accessory Plant Equipment	324	WP 2	166,596,149	Nuclear DA	166,596,149	-	-	-	-
229	Miscellaneous Equipment	325	WP 2	8,654,263	Nuclear DA	8,654,263	-	-	-	-
230				$ 926,653,891		$ 926,653,891	$ -	$ -	$ -	$ -
231										
232	Combustion Turbine & Other Production									
233	Land & Land Rights	340	WP 2	$ 32,120	Other Gen Plant - G	$ -	$ -	$ 14,850	$ 17,009	$ 258
234	Structures & Improvements	341	WP 2	6,738,057	Other Gen Plant - G	-	-	3,115,102	3,568,081	54,213
235	Fuel Holders, Producers and Accessories	342	WP 2	10,373,600	Other Gen Plant - G	-	-	4,795,866	5,493,252	83,464
236	Prime movers	343	WP 2	1,190,306	Other Gen Plant - G	-	-	550,296	630,317	9,577
237	Generator/PV	344	WP 2	372,495,368	Other Gen Plant - G	-	-	172,210,040	197,251,786	2,997,025
238	Accessory Elec Equip.	345	WP 2	3,162,172	Other Gen Plant - G	-	-	1,461,918	1,674,501	25,442

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related Base Load Nuclear	Base Load Coal	Intermediate Gas	Peak Gas	Renewable Solar
A		B	C	D	E	F	G	H	I	J
239	Miscellaneous Equipment	346	WP 2	2,114,443	Other Gen Plant - G	-	-	977,538	1,119,686	17,012
240				$ 396,106,067		$ -	$ -	$ 183,125,610	$ 209,754,633	$ 3,186,992
241										
242	**Total Power Generation Plant**			**$ 2,002,415,168**		**$ 926,653,891**	**$ 510,547,883**	**$ 352,232,937**	**$ 209,754,633**	**$ 3,186,992**
243										
273										
274	**Subtotal Plant in Service Before General Plant**			**$ 2,002,415,168**		**$ 926,653,891**	**$ 510,547,883**	**$ 352,232,937**	**$ 209,754,633**	**$ 3,186,992**
275										
276	General Plant									
277	Land & Land Rights	389	WP 2	$ 10,776,642	Prod Labor	$ 699,669	$ 4,094,624	$ 5,471,885	$ 485,483	$ 24,981
278	Structures & Improvements	390	WP 2	28,502,655	Prod Labor	1,850,522	10,829,686	14,472,343	1,284,033	66,072
279	Office Furniture & Equipment	391	WP 2	16,996,420	Prod Labor	1,103,485	6,457,851	8,630,004	765,682	39,399
280	Transportation Equipment	392	WP 2	1,849,619	Prod Labor	120,086	702,769	939,152	83,325	4,288
281	Stores Equipment	393	WP 2	321,151	Prod Labor	20,851	122,023	163,066	14,468	744
282	Tools, Shop & Garage Equipment	394	WP 2	334,174	Prod Labor	21,696	126,970	169,678	15,054	775
283	Laboratory Equipment	395	WP 2	402,713	Prod Labor	26,146	153,012	204,479	18,142	934
284	Power Operated Equipment	396	WP 2	951,880	Prod Labor	61,800	361,670	483,321	42,882	2,207
285	Communications Equipment	397	WP 2	22,459,793	Prod Labor	1,458,192	8,533,679	11,404,054	1,011,804	52,064
286	Miscellaneous Equipment	398	WP 2	145,242	Prod Labor	9,430	55,185	73,747	6,543	337
287	Other Tangible Property	399	WP 2	-	Prod Labor	-	-	-	-	-
288				$ 82,740,289		$ 5,371,877	$ 31,437,469	$ 42,011,729	$ 3,727,415	$ 191,799
289										
290	**Total Plant in Service - Gross**			**$ 2,085,155,457**		**$ 932,025,768**	**$ 541,985,352**	**$ 394,244,666**	**$ 213,482,048**	**$ 3,378,791**
291										
292										
293										
294	**Accumulated Depreciation**									
301										
302	Steam Power Generation									
303	Land & Land Rights	310	WP 2	$ -	Steam Plant - AD	$ -	$ -	$ -	$ -	$ -
304	Structures & Improvements	311	WP 2	76,972,099	Steam Plant - AD	-	50,349,892	26,622,207	-	-
305	Boiler Plant Equipment	312	WP 2	157,557,508	Steam Plant - AD	-	103,063,365	54,494,143	-	-
306	Engines and Engine Driven Generators	313	WP 2	-	Steam Plant - AD	-	-	-	-	-
307	Turbogenerator Units	314	WP 2	57,161,693	Steam Plant - AD	-	37,391,277	19,770,416	-	-
308	Accessory Plt Equipment	315	WP 2	17,071,461	Steam Plant - AD	-	11,166,984	5,904,477	-	-
309	Miscellaneous Equipment	316	WP 2	51,449,069	Steam Plant - AD	-	33,654,469	17,794,601	-	-
310				$ 360,211,830		$ -	$ 235,625,987	$ 124,585,843	$ -	$ -
311										
312	Nuclear Power Generation									
313	Land & Land Rights	320	WP 2	$ -	Nuclear DA	$ -	$ -	$ -	$ -	$ -
314	Structures & Improvements	321	WP 2	215,190,836	Nuclear DA	215,190,836	-	-	-	-
315	Reactor Plant Equipment	322	WP 2	138,286,653	Nuclear DA	138,286,653	-	-	-	-
316	Turbogenerator Units	323	WP 2	17,624,900	Nuclear DA	17,624,900	-	-	-	-
317	Accessory Plant Equipment	324	WP 2	87,610,824	Nuclear DA	87,610,824	-	-	-	-
318	Miscellaneous Equipment	325	WP 2	3,604,788	Nuclear DA	3,604,788	-	-	-	-
319				$ 462,318,000		$ 462,318,000	$ -	$ -	$ -	$ -
320										
321	Combustion Turbine & Other Productior									
322	Land & Land Rights	340	WP 2	$ -	Other Gen Plant - AD	$ -	$ -	$ -	$ -	$ -
323	Structures & Improvements	341	WP 2	702,713	Other Gen Plant - AD	-	-	319,161	376,537	6,930
324	Fuel Holders, Producers and Accessories	342	WP 2	1,671,650	Other Gen Plant - AD	-	-	759,237	895,726	16,486
325	Prime movers	343	WP 2	236,787	Other Gen Plant - AD	-	-	107,545	126,878	2,335
326	Generator/PV	344	WP 2	80,054,172	Other Gen Plant - AD	-	-	36,359,349	42,895,705	789,506
327	Accessory Elec Equip.	345	WP 2	823,602	Other Gen Plant - AD	-	-	374,067	441,314	8,122
328	Miscellaneous Equipment	346	WP 2	279,879	Other Gen Plant - AD	-	-	127,116	149,968	2,760
329				$ 83,768,802		$ -	$ -	$ 38,046,476	$ 44,886,128	$ 826,141

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Base Load Nuclear	Base Load Coal	Intermediate Gas	Peak Gas	Renewable Solar
A		B	C	D	E	F	G	H	I	J
330										
331	**Total Power Generation Plant**			**$ 906,298,632**		**$ 462,318,000**	**$ 235,625,987**	**$ 162,632,319**	**$ 44,886,128**	**$ 826,141**
332										
362										
363	**Subtotal Plant in Service Before General Plant**			**$ 906,298,632**		**$ 462,318,000**	**$ 235,625,987**	**$ 162,632,319**	**$ 44,886,128**	**$ 826,141**
364										
365	General Plant									
366	Land & Land Rights	389	WP 2	$ -	Prod Labor	$ -	$ -	$ -	$ -	$ -
367	Structures & Improvements	390	WP 2	14,782,554	Prod Labor	959,751	5,616,684	7,505,904	665,948	34,267
368	Office Furniture & Equipment	391	WP 2	6,718,817	Prod Labor	436,216	2,552,839	3,411,508	302,680	15,575
369	Transportation Equipment	392	WP 2	1,093,807	Prod Labor	71,015	415,596	555,385	49,276	2,536
370	Stores Equipment	393	WP 2	316,077	Prod Labor	20,521	120,095	160,489	14,239	733
371	Tools, Shop & Garage Equipment	394	WP 2	154,304	Prod Labor	10,018	58,628	78,349	6,951	358
372	Laboratory Equipment	395	WP 2	215,441	Prod Labor	13,987	81,858	109,391	9,706	499
373	Power Operated Equipment	396	WP 2	175,904	Prod Labor	11,421	66,835	89,316	7,924	408
374	Communications Equipment	397	WP 2	17,089,014	Prod Labor	1,109,497	6,493,032	8,677,019	769,853	39,614
375	Miscellaneous Equipment	398	WP 2	99,532	Prod Labor	6,462	37,817	50,538	4,484	231
376	Other Tangible Property	399	WP 2	-	Prod Labor	-	-	-	-	-
377				$ 40,645,451		$ 2,638,888	$ 15,443,384	$ 20,637,898	$ 1,831,060	$ 94,220
378										
379	**Total Plant in Service - Accumulated Depreciation**			**$ 946,944,083**		**$ 464,956,888**	**$ 251,069,371**	**$ 183,270,217**	**$ 46,717,188**	**$ 920,361**
380										
381										
382										
383	**Net Plant In Service**									
390										
391	Steam Power Generation									
392	Land & Land Rights	310	WP 2	$ 9,234,828	Steam Plant - Net	$ -	$ 7,948,939	$ 1,285,889	$ -	$ -
393	Structures & Improvements	311	WP 2	12,476,645	Steam Plant - Net	-	10,739,354	1,737,291	-	-
394	Boiler Plant Equipment	312	WP 2	254,278,143	Steam Plant - Net	-	218,871,580	35,406,563	-	-
395	Engines and Engine Driven Generators	313	WP 2	-	Steam Plant - Net	-	-	-	-	-
396	Turbogenerator Units	314	WP 2	18,496,121	Steam Plant - Net	-	15,920,658	2,575,464	-	-
397	Accessory Plt Equipment	315	WP 2	13,643,601	Steam Plant - Net	-	11,743,819	1,899,782	-	-
398	Miscellaneous Equipment	316	WP 2	11,314,042	Steam Plant - Net	-	9,738,636	1,575,406	-	-
399				$ 319,443,380		$ -	$ 274,962,985	$ 44,480,395	$ -	$ -
400										
401	Nuclear Power Generation									
402	Land & Land Rights	320	WP 2	$ 2,782,002	Nuclear DA	$ 2,782,002	$ -	$ -	$ -	$ -
403	Structures & Improvements	321	WP 2	191,529,059	Nuclear DA	191,529,059	-	-	-	-
404	Reactor Plant Equipment	322	WP 2	155,223,155	Nuclear DA	155,223,155	-	-	-	-
405	Turbogenerator Units	323	WP 2	30,766,875	Nuclear DA	30,766,875	-	-	-	-
406	Accessory Plant Equipment	324	WP 2	78,985,326	Nuclear DA	78,985,326	-	-	-	-
407	Miscellaneous Equipment	325	WP 2	5,049,475	Nuclear DA	5,049,475	-	-	-	-
408				$ 464,335,891		$ 464,335,891	$ -	$ -	$ -	$ -
409										
410	Combustion Turbine & Other Productior									
411	Land & Land Rights	340	WP 2	$ 32,120	Other Gen Plant - Net	$ -	$ -	$ 14,920	$ 16,955	$ 243
412	Structures & Improvements	341	WP 2	6,035,344	Other Gen Plant - Net	-	-	2,803,392	3,185,777	45,618
413	Fuel Holders, Producers and Accessories	342	WP 2	8,701,949	Other Gen Plant - Net	-	-	4,042,020	4,593,355	65,774
414	Prime movers	343	WP 2	953,520	Other Gen Plant - Net	-	-	442,906	503,319	7,207
415	Generator/PV	344	WP 2	292,441,196	Other Gen Plant - Net	-	-	135,837,733	154,366,109	2,210,413
416	Accessory Elec Equip.	345	WP 2	2,338,570	Other Gen Plant - Net	-	-	1,086,256	1,234,422	17,676
417	Miscellaneous Equipment	346	WP 2	1,834,565	Other Gen Plant - Net	-	-	852,148	968,381	13,867
418				$ 312,337,264		$ -	$ -	$ 145,079,375	$ 164,868,319	$ 2,360,797
419										
420	**Total Power Generation Plant**			**$ 1,096,116,536**		**$ 464,335,891**	**$ 274,962,985**	**$ 189,559,770**	**$ 164,868,319**	**$ 2,360,797**

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Base Load Nuclear	Base Load Coal	Intermediate Gas	Peak Gas	Renewable Solar
A		B	C	D	E	F	G	H	I	J
421										
451										
452	**Subtotal Plant in Service Before General Plant**			**$ 1,096,116,536**		**$ 464,335,891**	**$ 274,962,985**	**$ 189,559,770**	**$ 164,868,319**	**$ 2,360,797**
453										
454	General Plant									
455	Land & Land Rights	389	WP 2	$ 10,776,642	Prod Labor	$ 699,669	$ 4,094,624	$ 5,471,885	$ 485,483	$ 24,981
456	Structures & Improvements	390	WP 2	13,720,101	Prod Labor	890,772	5,213,001	6,966,439	618,085	31,804
457	Office Furniture & Equipment	391	WP 2	10,277,603	Prod Labor	667,269	3,905,012	5,218,496	463,002	23,824
458	Transportation Equipment	392	WP 2	755,812	Prod Labor	49,071	287,174	383,767	34,049	1,752
459	Stores Equipment	393	WP 2	5,074	Prod Labor	329	1,928	2,576	229	12
460	Tools, Shop & Garage Equipment	394	WP 2	179,869	Prod Labor	11,678	68,342	91,329	8,103	417
461	Laboratory Equipment	395	WP 2	187,272	Prod Labor	12,159	71,155	95,088	8,437	434
462	Power Operated Equipment	396	WP 2	775,976	Prod Labor	50,380	294,835	394,005	34,957	1,799
463	Communications Equipment	397	WP 2	5,370,779	Prod Labor	348,695	2,040,647	2,727,035	241,951	12,450
464	Miscellaneous Equipment	398	WP 2	45,710	Prod Labor	2,968	17,368	23,210	2,059	106
465	Other Tangible Property	399	WP 2	-	Prod Labor	-	-	-	-	-
466				$ 42,094,838		$ 2,732,989	$ 15,994,084	$ 21,373,831	$ 1,896,355	$ 97,580
467										
468	**Total Plant in Service - Net**			**$ 1,138,211,374**		**$ 467,068,880**	**$ 290,957,069**	**$ 210,933,601**	**$ 166,764,673**	**$ 2,458,377**
469										
470										
471										
472	**Depreciation Expense**									
479										
480	Steam Power Generation									
481	Land & Land Rights	310	WP 2	$ -	Steam Plant - Depr	$ -	$ -	$ -	$ -	$ -
482	Structures & Improvements	311	WP 2	2,444,311	Steam Plant - Depr	-	1,877,909	566,402	-	-
483	Boiler Plant Equipment	312	WP 2	12,389,477	Steam Plant - Depr	-	9,518,556	2,870,921	-	-
484	Engines and Engine Driven Generators	313	WP 2	-	Steam Plant - Depr	-	-	-	-	-
485	Turbogenerator Units	314	WP 2	2,042,250	Steam Plant - Depr	-	1,569,015	473,235	-	-
486	Accessory Plt Equipment	315	WP 2	830,619	Steam Plant - Depr	-	638,146	192,473	-	-
487	Miscellaneous Equipment	316	WP 2	1,701,091	Steam Plant - Depr	-	1,306,910	394,181	-	-
488				$ 19,407,749		$ -	$ 14,910,535	$ 4,497,213	$ -	$ -
489										
490	Nuclear Power Generation									
491	Land & Land Rights	320	WP 2	$ -	Nuclear DA	$ -	$ -	$ -	$ -	$ -
492	Structures & Improvements	321	WP 2	9,634,365	Nuclear DA	9,634,365	-	-	-	-
493	Reactor Plant Equipment	322	WP 2	6,952,649	Nuclear DA	6,952,649	-	-	-	-
494	Turbogenerator Units	323	WP 2	4,126,237	Nuclear DA	4,126,237	-	-	-	-
495	Accessory Plant Equipment	324	WP 2	3,946,323	Nuclear DA	3,946,323	-	-	-	-
496	Miscellaneous Equipment	325	WP 2	205,002	Nuclear DA	205,002	-	-	-	-
497				$ 24,864,576		$ 24,864,576	$ -	$ -	$ -	$ -
498										
499	Combustion Turbine & Other Productior									
500	Land & Land Rights	340	WP 2	$ -	Other Gen Plant - Depr	$ -	$ -	$ -	$ -	$ -
501	Structures & Improvements	341	WP 2	219,925	Other Gen Plant - Depr	-	-	101,723	116,419	1,762
502	Fuel Holders, Producers and Accessories	342	WP 2	337,791	Other Gen Plant - Depr	-	-	156,240	178,812	2,706
503	Prime movers	343	WP 2	38,618	Other Gen Plant - Depr	-	-	17,862	20,443	309
504	Generator/PV	344	WP 2	12,149,942	Other Gen Plant - Depr	-	-	5,619,771	6,431,646	97,341
505	Accessory Elec Equip.	345	WP 2	103,035	Other Gen Plant - Depr	-	-	47,657	54,542	825
506	Miscellaneous Equipment	346	WP 2	71,884	Other Gen Plant - Depr	-	-	33,249	38,052	576
507				$ 12,921,195		$ -	$ -	$ 5,976,502	$ 6,839,913	$ 103,520
508										
509	**Total Power Generation Plant**			**$ 57,193,519**		**$ 24,864,576**	**$ 14,910,535**	**$ 10,473,715**	**$ 6,839,913**	**$ 103,520**
510										
540										

Test Year Revenue Requirement - Production
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Base Load Nuclear	Base Load Coal	Intermediate Gas	Peak Gas	Renewable Solar
A		B	C	D	E	F	G	H	I	J
541	**Subtotal Plant in Service Before General Plant**			**$ 57,193,519**		**$ 24,864,576**	**$ 14,910,535**	**$ 10,473,715**	**$ 6,839,913**	**$ 103,520**
542										
543	General Plant									
544	Land & Land Rights	389	WP 2	$ -	Prod Labor	$ -	$ -	$ -	$ -	$ -
545	Structures & Improvements	390	WP 2	780,932	Prod Labor	50,702	296,718	396,521	35,181	1,810
546	Office Furniture & Equipment	391	WP 2	1,396,364	Prod Labor	90,658	530,553	709,010	62,906	3,237
547	Transportation Equipment	392	WP 2	137,729	Prod Labor	8,942	52,331	69,933	6,205	319
548	Stores Equipment	393	WP 2	358	Prod Labor	23	136	182	16	1
549	Tools, Shop & Garage Equipment	394	WP 2	22,197	Prod Labor	1,441	8,434	11,271	1,000	51
550	Laboratory Equipment	395	WP 2	31,277	Prod Labor	2,031	11,884	15,881	1,409	73
551	Power Operated Equipment	396	WP 2	18,627	Prod Labor	1,209	7,077	9,458	839	43
552	Communications Equipment	397	WP 2	1,402,687	Prod Labor	91,069	532,956	712,220	63,190	3,252
553	Miscellaneous Equipment	398	WP 2	7,545	Prod Labor	490	2,867	3,831	340	17
554	Other Tangible Property	399	WP 2	-	Prod Labor	-	-	-	-	-
555				$ 3,797,717		$ 246,565	$ 1,442,956	$ 1,928,307	$ 171,086	$ 8,803
556										
557	**Total Plant Depreciation**			**$ 60,991,236**		**$ 25,111,141**	**$ 16,353,491**	**$ 12,402,022**	**$ 7,010,998**	**$ 112,323**
558										
559										
560										
561										
562										
563	**Labor**									
564										
565	**Power Production Expenses**									
566	Steam Power Generation									
567	**Operation**									
568	Operation Supervision and Engineering	500	WP 3.1	$ 5,944,916	FERC 500	$ -	$ 2,558,840	$ 3,386,076	$ -	$ -
569	Fuel	501	WP 3.1	662,876	501 Non-Recoverable	-	552,118	110,757	-	-
570	Steam Expenses	502	WP 3.1	2,694,376	FERC 502	-	2,370,015	324,361	-	-
571	Steam from other Sources	503	WP 3.1	-		-	-	-	-	-
572	Steam Transferred	504	WP 3.1	-		-	-	-	-	-
573	Electric Expenses	505	WP 3.1	9,218	FERC 505	-	9,014	204	-	-
574	Miscellaneous Steam Expenses	506	WP 3.1	369,140	FERC 506	-	280,543	88,597	-	-
575	Rents	507	WP 3.1	-		-	-	-	-	-
576				$ 9,680,526		$ -	$ 5,770,531	$ 3,909,995	$ -	$ -
577										
578	**Maintenance**									
579	Maintenance Supervision	510	WP 3.1	$ 2,196,111	FERC 510	$ -	$ 1,186,634	$ 1,009,477	$ -	$ -
580	Maintenance of Structures	511	WP 3.1	8,944	FERC 511	-	5,930	3,014	-	-
581	Maintenance of Boiler Plant	512	WP 3.1	181,843	FERC 512	-	144,674	37,169	-	-
582	Maintenance of Electric Plant	513	WP 3.1	64,808	FERC 513	-	56,435	8,372	-	-
583	Maintenance of Miscellaneous Steam Plant	514	WP 3.1	972,462	FERC 514	-	455,084	517,377	-	-
584	Rents	515	WP 3.1	-		-	-	-	-	-
585				$ 3,424,167		$ -	$ 1,848,757	$ 1,575,410	$ -	$ -
586										
587	Nuclear Power Generation									
588	**Operation**									
589	Operation Supervision	517	WP 3.1	$ 275,541	Nuclear DA	$ 275,541	$ -	$ -	$ -	$ -
590	Nuclear Fuel Expense	518	WP 3.1	-	Nuclear Fuel	-	-	-	-	-
591	Coolants and Water	519	WP 3.1	-	Nuclear DA	-	-	-	-	-
592	Steam Expenses	520	WP 3.1	-	Nuclear DA	-	-	-	-	-
593	Electric Expenses	523	WP 3.1	-	Nuclear DA	-	-	-	-	-
594	Misc Nuclear Power Expenses	524	WP 3.1	-	Nuclear DA	-	-	-	-	-
595	Rents	525	WP 3.1	-	Nuclear DA	-	-	-	-	-
596				$ 275,541		$ 275,541	$ -	$ -	$ -	$ -

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Base Load Nuclear	Base Load Coal	Intermediate Gas	Peak Gas	Renewable Solar
A		B	C	D	E	F	G	H	I	J
597										
598	**Maintenance**									
599	Maintenance Supervision	528	WP 3.1	$ -	Nuclear DA	$ -	$ -	$ -	$ -	$ -
600	Maintenance of Structures	529	WP 3.1	-	Nuclear DA	-	-	-	-	-
601	Maintenance of Reactor Plant	530	WP 3.1	-	Nuclear DA	-	-	-	-	-
602	Maintenance of Electric Plant	531	WP 3.1	-	Nuclear DA	-	-	-	-	-
603	Maintenance of Miscellaneous	532	WP 3.1	-	Nuclear DA	-	-	-	-	-
604				$ -		$ -	$ -	$ -	$ -	$ -
605										
606	Hydraulic Power Generation									
607	**Maintenance**									
608	Maintenance Supervision	541	WP 3.1	$ -		$ -	$ -	$ -	$ -	$ -
609	Maintenance of Structures	542	WP 3.1	-		-	-	-	-	-
610	Maintenance of Reservoirs, Dams & Waterways	543	WP 3.1	-		-	-	-	-	-
611	Maintenance of Electric Plant	544	WP 3.1	-		-	-	-	-	-
612	Maintenance of Miscellaneous Hydraulic Plant	545	WP 3.1	-		-	-	-	-	-
613				$ -		$ -	$ -	$ -	$ -	$ -
614										
615	Other Power Generation									
616	**Operation**									
617	Operation Supervision	546	WP 3.1	$ 1,590,051	FERC 546	$ -	$ -	$ 1,348,197	$ 241,854	$ -
618	Fuel	547	WP 3.1	-	Other Fuel	-	-	-	-	-
619	Generation Expenses	548	WP 3.1	2,001,778	FERC 548	-	-	1,731,029	270,749	-
620	Miscellaneous Other Power Generation Expenses	549	WP 3.1	89,637	FERC 549	-	-	63,592	26,045	-
621	Rents	550	WP 3.1	15	FERC 550	-	-	9	6	-
622				$ 3,681,481		$ -	$ -	$ 3,142,827	$ 538,654	$ -
623										
624	**Maintenance**									
625	Maintenance Supervision and Engineering	551	WP 3.1	$ 43,116	FERC 551	$ -	$ -	$ 38,890	$ 4,225	$ -
626	Maintenance of Structures	552	WP 3.1	50,665	FERC 552	-	-	37,230	13,435	-
627	Maintenance of Generating and Electric Equipment	553	WP 3.1	1,287,085	FERC 553	-	-	1,081,495	205,590	-
628	Maintenance of Misc Other Power Generation Plant	554	WP 3.1	795,529	FERC 554	-	-	678,177	117,352	-
629				$ 2,176,394		$ -	$ -	$ 1,835,792	$ 340,602	$ -
630										
631	Other Power Supply									
632	Purchased Power	555	WP 3.1	$ -	555 Non-Recoverable	$ -	$ -	$ -	$ -	$ -
633	System Control and Load Dispatching	556	WP 3.1	1,657,074	556 Non-Recoverable	874,603	385,596	293,164	64,733	38,979
634	Other Power Expenses	557	WP 3.1	446,051	Prod RR - Demand	235,426	103,795	78,914	17,425	10,492
635				$ 2,103,125		$ 1,110,029	$ 489,390	$ 372,078	$ 82,158	$ 49,471
636										
637	**Total Power Production Expense**			**$ 21,341,235**		**$ 1,385,570**	**$ 8,108,678**	**$ 10,836,102**	**$ 961,414**	**$ 49,471**
638										
659										
660	**Total Transmission Expenses**			**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
661										
687										
688	**Total Distribution Expenses**			**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
689										
710										
711	**Total Customer and Information Expenses**			**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
712										
713	**General and Administrative Expenses**									
714	Administrative and General Salaries	920	WP 3.1	$ 10,189,883	Prod 920	$ 2,721,351	$ 3,034,723	$ 4,055,479	$ 359,815	$ 18,515
715	Office Supplies and Expenses	921	WP 3.1	2,840	Prod 921	428	980	1,310	116	6
716	Administrative Expense Transferred	922	WP 3.1	-	Prod 920	-	-	-	-	-
717	Outside Services Employed	923	WP 3.1	2,300	Prod 923	1,359	430	457	53	1

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Base Load Nuclear	Base Load Coal	Intermediate Gas	Peak Gas	Renewable Solar
A		B	C	D	E	F	G	H	I	J
718	Property Insurance	924	WP 3.1	-	Prod 924	-	-	-	-	-
719	Injuries and Damages	925	WP 3.1	-	Prod 925	-	-	-	-	-
720	Employee Pension and Benefits	926	WP 3.1	-	Prod 926	-	-	-	-	-
721	Regulatory Commission Expense	928	WP 3.1	-	Prod RR	-	-	-	-	-
722	General Expenses	930	WP 3.1	240,083	Prod 930	38,836	105,160	87,888	7,798	401
723	Rents	931	WP 3.1	-	Prod 931	-	-	-	-	-
724	Maintenance of General Plant	935	WP 3.1	-	Prod 935	-	-	-	-	-
725				$ 10,435,106		$ 2,761,974	$ 3,141,294	$ 4,145,133	$ 367,782	$ 18,923
726										
727	**Total Electric Labor**			**$ 31,776,341**		**$ 4,147,545**	**$ 11,249,972**	**$ 14,981,235**	**$ 1,329,196**	**$ 68,394**
728										
729										
730										
731	**Allocation Factors**									
732	1 Regulatory					0.0%	0.0%	0.0%	0.0%	0.0%
733	Direct Assignment to Regulatory Clause									
734										
735	2 Community Benefit					0.0%	0.0%	0.0%	0.0%	0.0%
736	Direct Assignment to Community Benefit Clause									
737										
738	3 FERC 513	WP 24 - Prod O&M				0.0%	87.1%	12.9%	0.0%	0.0%
739	Steam Generation FERC 513						1	0		
740										
741	4 FERC 514	WP 24 - Prod O&M				0.0%	46.8%	53.2%	0.0%	0.0%
742	Steam Generation FERC 514						0	1		
743										
744	5 556 Non-Recoverable	WP 44 - PCR & WP 3 - Labor				52.8%	23.3%	17.7%	3.9%	2.4%
745	Direct Assignment to Green Choice and Remainder to Demand Related Revenue Req			$ 1,802,970		$ 951,607	$ 419,545	$ 318,975	$ 70,432	$ 42,410
746	Other FERC 556 Non-Recoverable to Production Demand Related Revenue Requirement			$ 1,802,970	Prod RR - Demand	$ 951,607	$ 419,545	$ 318,975	$ 70,432	$ 42,410
747	FERC 556 Non-Recoverable Direct to Green Choice			$ -	Green Choice DA	$ -	$ -	$ -	$ -	$ -
748										
749	6 555 Non-Recoverable	WP 44 - PCR				0.0%	0.0%	0.0%	0.0%	0.0%
750	Direct Assignments to GC and Remainder to Demand Related Wind Costs			$ 10,403,215		$ -	$ -	$ -	$ -	$ -
751	Direct Assignment to Green Choice			$ 10,057,082	Green Choice DA	$ -	$ -	$ -	$ -	$ -
752	Other Non-Recoverable FERC 555 Allocated to Energy Related Winc			$ 346,133	Wind Energy DA	$ -	$ -	$ -	$ -	$ -
753										
754	7 Prod RR - Demand					52.8%	23.3%	17.7%	3.9%	2.4%
755	Revenue Requirement Associated with Demand Related Generation					174,998,382	77,153,403	58,658,794	12,952,332	7,799,190
756										
757	8 Steam Fuel	WP 44 - PCR				0.0%	0.0%	0.0%	0.0%	0.0%
758	Steam Generation Fuel for Base Load and Intermediate									
759										
760	9 Nuclear DA					100.0%	0.0%	0.0%	0.0%	0.0%
761	Direct Assignment to Demand Related Nuclear Generation					1				
762										
763	10 Nuclear Fuel	WP 44 - PCR				0.0%	0.0%	0.0%	0.0%	0.0%
764	Nuclear Generation Fuel for Base Load Resource Type									
765										
766	11 T Prod Plant - Depr					41.2%	26.8%	20.3%	11.5%	0.2%
767	Total Depreciation for Production Plant In Service, Including General Plant					25,111,141	16,353,491	12,402,022	7,010,998	112,323
768										
769	12 Other Fuel	WP 44 - PCR				0.0%	0.0%	0.0%	0.0%	0.0%
770	Other Generation Fuel for Intermediate and Peak									
771										
772	13 FERC 500	WP 24 - Prod O&M				0.0%	43.0%	57.0%	0.0%	0.0%
773	Steam Generation FERC 500						0	1		
774										

Test Year Revenue Requirement - Production
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.			FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related Base Load Nuclear	Demand Related Base Load Coal	Demand Related Intermediate Gas	Demand Related Peak Gas	Demand Related Renewable Solar
A			B	C	D	E	F	G	H	I	J
775	14	FERC 502	WP 24 - Prod O&M				0.0%	88.0%	12.0%	0.0%	0.0%
776		Steam Generation FERC 502						1	0		
777											
778	15	FERC 505	WP 24 - Prod O&M				0.0%	97.8%	2.2%	0.0%	0.0%
779		Steam Generation FERC 505						1	0		
780											
781	16	FERC 506	WP 24 - Prod O&M				0.0%	76.0%	24.0%	0.0%	0.0%
782		Steam Generation FERC 506						1	0		
783											
784	17	FERC 510	WP 24 - Prod O&M				0.0%	54.0%	46.0%	0.0%	0.0%
785		Steam Generation FERC 510						1	0		
786											
787	18	FERC 511	WP 24 - Prod O&M				0.0%	66.3%	33.7%	0.0%	0.0%
788		Steam Generation FERC 511						1	0		
789											
790	19	FERC 512	WP 24 - Prod O&M				0.0%	79.6%	20.4%	0.0%	0.0%
791		Steam Generation FERC 512						1	0		
792											
793	20	Prod RR					23.2%	10.2%	7.8%	1.7%	1.0%
794		Generation Revenue Requirement, Excluding DA to Regulatory and Community Benefit Adjustment Clauses and Green Choice					174,998,382	77,153,403	58,658,794	12,952,332	7,799,190
795											
796	21	Prod 920	WP 6 - G&A				26.7%	29.8%	39.8%	3.5%	0.2%
797		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Excluding G&A and DA			$ 8,849,743		$ 2,363,448	$ 2,635,607	$ 3,522,116	$ 312,493	$ 16,080
798		FERC 920 STP Direct to Production			$ 1,913,089	Nuclear DA	$ 1,913,089	$ -	$ -	$ -	$ -
799		FERC 920 FPP Direct to Production			$ -	Base Coal DA	$ -	$ -	$ -	$ -	$ -
800		Other Allocated FERC 920 to Productior			$ 6,936,655	Prod Labor	$ 450,359	$ 2,635,607	$ 3,522,116	$ 312,493	$ 16,080
801											
802	22	Prod 921	WP 6 - G&A				15.1%	34.5%	46.1%	4.1%	0.2%
803		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Excluding G&A and DA			$ 5,273,986		$ 794,512	$ 1,820,165	$ 2,432,394	$ 215,810	$ 11,105
804		FERC 921 STP Direct to Production			$ 483,491	Nuclear DA	$ 483,491	$ -	$ -	$ -	$ -
805		FERC 921 FPP Direct to Production			$ -	Base Coal DA	$ -	$ -	$ -	$ -	$ -
806		Other Allocated FERC 921 to Productior			$ 4,790,494	Prod Labor	$ 311,021	$ 1,820,165	$ 2,432,394	$ 215,810	$ 11,105
807											
808	23	Prod Labor					6.5%	38.0%	50.8%	4.5%	0.2%
809		Total Production Labor, Excluding G&A and DA to Regulatory and Community Benefit Adjustment Clauses and Green Choice					1,385,570	8,108,678	10,836,102	961,414	49,471
810											
811	24	Prod 923	WP 6 - G&A				59.1%	18.7%	19.9%	2.3%	0.0%
812		Based on Direct Allocations in WP 6 - G&A and Total Production O&M, Excluding G&A, Fuel and Purchased Power, and DA					$ 3,400,362	$ 1,075,132	$ 1,143,592	$ 132,919	$ 2,004
813		FERC 923 STP Direct to Production			$ 1,513,819	Nuclear DA	$ 1,513,819	$ -	$ -	$ -	$ -
814		FERC 923 FPP Direct to Production			$ -	Base Coal DA	$ -	$ -	$ -	$ -	$ -
815		Other Allocated FERC 923 to Productior			$ 4,240,190	Prod O&M EXAGF	$ 1,886,542	$ 1,075,132	$ 1,143,592	$ 132,919	$ 2,004
816											
817	25	Prod 924	WP 6 - G&A				48.1%	29.5%	11.9%	10.4%	0.1%
818		Based on Direct Allocations in WP 6 - G&A and Generation Net Plant			$ 2,258,015		$ 1,085,099	$ 665,414	$ 269,512	$ 234,590	$ 3,359
819		FERC 924 STP Direct to Production			$ 425,511	Nuclear DA	$ 425,511	$ -	$ -	$ -	$ -
820		FERC 924 FPP and Boiler Insurance Direct to Productior			$ 275,473	Base Coal DA	$ -	$ 275,473	$ -	$ -	$ -
821		Other Allocated FERC 924 to Productior			$ 1,557,031	Prod Plant - Net	$ 659,588	$ 389,941	$ 269,512	$ 234,590	$ 3,359
822											
823	26	Prod 925	WP 6 - G&A				38.5%	31.8%	27.2%	2.4%	0.1%
824		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Excluding G&A and DA			$ 1,097,461		$ 422,460	$ 348,961	$ 298,220	$ 26,459	$ 1,361
825		FERC 925 STP Direct to Production			$ 384,328	Nuclear DA	$ 384,328	$ -	$ -	$ -	$ -
826		FERC 925 FPP Direct to Production			$ 125,803	Base Coal DA	$ -	$ 125,803	$ -	$ -	$ -
827		Other Allocated FERC 925 to Productior			$ 587,331	Prod Labor	$ 38,132	$ 223,158	$ 298,220	$ 26,459	$ 1,361
828											
829	27	Prod 926	WP 6 - G&A				66.0%	33.3%	0.7%	0.1%	0.0%
830		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Excluding G&A and DA			$ 9,931,952		$ 6,550,387	$ 3,303,013	$ 71,849	$ 6,375	$ 328
831		FERC 926 STP Direct to Production			$ 6,541,200	Nuclear DA	$ 6,541,200	$ -	$ -	$ -	$ -

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.			FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Base Load Nuclear	Base Load Coal	Intermediate Gas	Peak Gas	Renewable Solar
A			B	C	D	E	F	G	H	I	J
832		FERC 926 FPP Direct to Production			$ 3,249,249	Base Coal DA	$ -	$ 3,249,249	$ -	$ -	$ -
833		Other Allocated FERC 926 to Productior			$ 141,503	Prod Labor	$ 9,187	$ 53,765	$ 71,849	$ 6,375	$ 328
834											
835	28	Prod 930		WP 6 - G&A			16.2%	43.8%	36.6%	3.2%	0.2%
836		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Excluding G&A and D/			$ 6,524,359		$ 1,055,389	$ 2,857,779	$ 2,388,383	$ 211,905	$ 10,904
837		FERC 930 STP Direct to Production			$ 749,995	Nuclear DA	$ 749,995	$ -	$ -	$ -	$ -
838		FERC 930 FPP Direct to Production			$ 1,070,546	Base Coal DA	$ -	$ 1,070,546	$ -	$ -	$ -
839		Other Allocated FERC 930 to Productior			$ 4,703,818	Prod Labor	$ 305,393	$ 1,787,232	$ 2,388,383	$ 211,905	$ 10,904
840											
841	29	Prod 935		WP 6 - G&A			98.7%	0.6%	0.4%	0.3%	0.0%
842		Based on Direct Allocations in WP 6 - G&A and Generation Net Plant			$ 895,159		$ 883,305	$ 5,150	$ 3,560	$ 3,099	$ 44
843		FERC 935 STP Direct to Production			$ 874,593	Nuclear DA	$ 874,593	$ -	$ -	$ -	$ -
844		FERC 935 FPP Direct to Production			$ -	Base Coal DA	$ -	$ -	$ -	$ -	$ -
845		Other Allocated FERC 935 to Productior			$ 20,566	Prod Plant - Net	$ 8,712	$ 5,150	$ 3,560	$ 3,099	$ 44
846											
847	30	555 Recoverable		WP 44 - PCR			0.0%	0.0%	0.0%	0.0%	0.0%
848		Direct Assignments of FERC 555 Recoverable			$ 96,511,902		$ -	$ -	$ -	$ -	$ -
849		FERC 555 Recoverable Direct to Economy Purchase Power			$ 23,084,089	Econ PP DA	$ -	$ -	$ -	$ -	$ -
850		FERC 555 Recoverable Direct to Wind			$ 58,628,188	Wind Energy DA	$ -	$ -	$ -	$ -	$ -
851		FERC 555 Recoverable Direct to Landfill Methane			$ 3,322,545	LF Gas Energy DA	$ -	$ -	$ -	$ -	$ -
852		FERC 555 Recoverable Direct to Solar			$ 11,477,080	Solar Energy DA	$ -	$ -	$ -	$ -	$ -
853											
854	31	556 Recoverable		WP 28.1 - FERC 556 & WP 44 - PCR			0.0%	0.0%	0.0%	0.0%	0.0%
855		Direct Assignments of FERC 556 Recoverable to Regulatory Clause			$ 21,079,958		$ -	$ -	$ -	$ -	$ -
856		FERC 556 Recoverable Direct to Regulatory			$ 9,839,798	Regulatory	$ -	$ -	$ -	$ -	$ -
857		Allocation to Demand Related Revenue Requirement			$ -	Prod RR - Demand	$ -	$ -	$ -	$ -	$ -
858		Allocation to Energy Related Revenue Requirement			$ 11,240,159	Prod RR - Energy	$ -	$ -	$ -	$ -	$ -
859											
860	32	Prod Debt Service		WP 5.3 - Debt			76.9%	14.6%	0.5%	0.3%	7.8%
861		Sub-functionalization of Debt Service Based on Detailed Allocation of Each Debt Issue					67,717,112	12,813,471	403,517	238,516	6,849,656
862											
863	33	Steam Plant - G		WP 26 - Prod Plant			0.0%	75.1%	24.9%	0.0%	0.0%
864								510,024,258	168,933,888		
865											
866	34	Steam Plant - AD		WP 26 - Prod Plant			0.0%	65.4%	34.6%	0.0%	0.0%
867								235,514,273	124,526,774		
868											
869	35	Steam Plant - Depr		WP 26 - Prod Plant			0.0%	76.8%	23.2%	0.0%	0.0%
870								14,895,218	4,492,593		
871											
872	36	Steam Plant - Net		WP 26 - Prod Plant			0.0%	86.1%	13.9%	0.0%	0.0%
873								274,509,985	44,407,114		
874											
875	37	Other Gen Plant - G		WP 26 - Prod Plant			0.0%	0.0%	46.2%	53.0%	0.8%
876									183,447,873	210,123,757	3,192,600
877											
878	38	Other Gen Plant - AD		WP 26 - Prod Plant			0.0%	0.0%	45.4%	53.6%	1.0%
879									38,124,043	44,977,639	827,825
880											
881	39	Other Gen Plant - Depr		WP 26 - Prod Plant			0.0%	0.0%	46.3%	52.9%	0.8%
882									5,985,724	6,850,467	103,680
883											
884	40	Other Gen Plant - Net		WP 26 - Prod Plant			0.0%	0.0%	46.4%	52.8%	0.8%
885									145,323,830	165,146,118	2,364,775
886											
887	41	Prod RR - Energy					0.0%	0.0%	0.0%	0.0%	0.0%
888		Revenue Requirement Associated with Energy Related Generation									

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.			FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Base Load Nuclear	Base Load Coal	Intermediate Gas	Peak Gas	Renewable Solar
A			B	C	D	E	F	G	H	I	J
889											
890	42	Prod Plant - Net	WP 26 - Prod Plant				42.4%	25.0%	17.3%	15.1%	0.2%
891		Net Production Plant In Service (excluding General Plant)					464,335,891	274,509,985	189,730,944	165,146,118	2,364,775
892											
893	43	FERC 546	WP 24 - Prod O&M				0.0%	0.0%	84.8%	15.2%	0.0%
894		Other Power Generation FERC 546							1	0	
895											
896	44	FERC 548	WP 24 - Prod O&M				0.0%	0.0%	86.5%	13.5%	0.0%
897		Other Power Generation FERC 548							1	0	
898											
899	45	FERC 549	WP 24 - Prod O&M				0.0%	0.0%	70.9%	29.1%	0.0%
900		Other Power Generation FERC 549							1	0	
901											
902	46	FERC 550	WP 24 - Prod O&M				0.0%	0.0%	57.3%	42.7%	0.0%
903		Other Power Generation FERC 550							1	0	
904											
905	47	FERC 551	WP 24 - Prod O&M				0.0%	0.0%	90.2%	9.8%	0.0%
906		Other Power Generation FERC 551							1	0	
907											
908	48	FERC 552	WP 24 - Prod O&M				0.0%	0.0%	73.5%	26.5%	0.0%
909		Other Power Generation FERC 552							1	0	
910											
911	49	FERC 553	WP 24 - Prod O&M				0.0%	0.0%	84.0%	16.0%	0.0%
912		Other Power Generation FERC 553							1	0	
913											
914	50	FERC 554	WP 24 - Prod O&M				0.0%	0.0%	85.2%	14.8%	0.0%
915		Other Power Generation FERC 554							1	0	
916											
917	51	Prod 931	WP 6 - G&A				6.5%	38.0%	50.8%	4.5%	0.2%
918		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Excluding G&A and DA			$ 562,234		$ 36,503	$ 213,623	$ 285,477	$ 25,328	$ 1,303
919		FERC 931 STP Direct to Production			$ -	Nuclear DA	$ -	$ -	$ -	$ -	$ -
920		FERC 931 FPP Direct to Production			$ -	Base Coal DA	$ -	$ -	$ -	$ -	$ -
921		Other Allocated FERC 931 to Production			$ 562,234	Prod Labor	$ 36,503	$ 213,623	$ 285,477	$ 25,328	$ 1,303
922											
923	52	Prod O&M EXAGF					44.5%	25.4%	27.0%	3.1%	0.0%
924		Total Production O&M, Excluding G&A, Commodity Fuel and Purchased Power, and DA to Regulatory, Community Benefit and GC					50,763,131	28,929,670	30,771,801	3,576,599	53,932
925											
926	53	Base Coal DA					0.0%	100.0%	0.0%	0.0%	0.0%
927		Direct Assignment to Demand Related Base Load Coal Generation						1			
928											
929	54	Green Choice DA					0.0%	0.0%	0.0%	0.0%	0.0%
930		Direct Assignment to Green Choice									
931											
932	55	501 Non-Recoverable	WP 44 - PCR				0.0%	83.3%	16.7%	0.0%	0.0%
933		Allocation of FERC 501 Non-Recoverable Based on Steam Fuel Expense			$ 131,529,489		$ -	$ 109,552,730	$ 21,976,759	$ -	$ -
934					$ 109,552,730	Base Coal DA	$ -	$ 109,552,730	$ -	$ -	$ -
935					$ 21,976,759	Int Gas DA	$ -	$ -	$ 21,976,759	$ -	$ -
936											
937	56	Solar Energy DA					0.0%	0.0%	0.0%	0.0%	0.0%
938		Direct Assignment of Solar to Energy									
939											
940	57	Wind Energy DA					0.0%	0.0%	0.0%	0.0%	0.0%
941		Direct Assignment of Wind to Energy									
942											
943	58	Econ PP DA					0.0%	0.0%	0.0%	0.0%	0.0%
944		Direct Assignment of Economy Purchase Power to Energy									
945											

Test Year Revenue Requirement - Production
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.			FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related Base Load Nuclear	Base Load Coal	Intermediate Gas	Peak Gas	Renewable Solar
A			B	C	D	E	F	G	H	I	J
946	61	Int Gas DA					0.0%	0.0%	100.0%	0.0%	0.0%
947		Direct Assignment to Intermediate Gas							1		
948											
949	62	Peak Gas DA					0.0%	0.0%	0.0%	100.0%	0.0%
950		Direct Assignment to Peak Gas								1	
951											
952	63	LF Gas Energy DA					0.0%	0.0%	0.0%	0.0%	0.0%
953		Direct Assignment of Landfill Methane to Energy									

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

			Energy Related								
Line		FERC	Base Load	Base Load	Intermediate	Peak	Economy	Renewable	Renewable	Renewable	Regulatory
No.		Account	Nuclear - Fuel	Coal - Fuel	Gas - Fuel	Gas - Fuel	Purch Pwr	Wind	Solar	LF Methane	Adj Clause
A		B	K	L	M	N	O	P	Q	R	S
1	**Power Production Expenses**										
2	Steam Power Generation										
3	**Operation**										
4	Operation Supervision and Engineering	500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Fuel - Recoverable	501	-	109,552,730	21,976,759	-	-	-	-	-	-
6	Fuel - Non-Recoverable	501	-	-	-	-	-	-	-	-	-
7	Steam Expenses	502	-	-	-	-	-	-	-	-	-
8	Steam from other Sources	503	-	-	-	-	-	-	-	-	-
9	Steam Transferred	504	-	-	-	-	-	-	-	-	-
10	Electric Expenses	505	-	-	-	-	-	-	-	-	-
11	Miscellaneous Steam Expenses	506	-	-	-	-	-	-	-	-	-
12	Rents	507	-	-	-	-	-	-	-	-	-
13			$ -	$ 109,552,730	$ 21,976,759	$ -	$ -	$ -	$ -	$ -	$ -
14											
15	**Maintenance**										
16	Maintenance Supervision	510	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Maintenance of Structures	511	-	-	-	-	-	-	-	-	-
18	Maintenance of Boiler Plant	512	-	-	-	-	-	-	-	-	-
19	Maintenance of Electric Plant	513	-	-	-	-	-	-	-	-	-
20	Maintenance of Miscellaneous Steam Plant	514	-	-	-	-	-	-	-	-	-
21	Rents	515	-	-	-	-	-	-	-	-	-
22			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23											
24	Nuclear Power Generation										
25	**Operation**										
26	Operation Supervision	517	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Nuclear Fuel Expense	518	19,347,060	-	-	-	-	-	-	-	-
28	Coolants and Water	519	-	-	-	-	-	-	-	-	-
29	Steam Expenses	520	-	-	-	-	-	-	-	-	-
30	Electric Expenses	523	-	-	-	-	-	-	-	-	-
31	Misc Nuclear Power Expenses	524	-	-	-	-	-	-	-	-	-
32	Rents	525	-	-	-	-	-	-	-	-	-
33			$ 19,347,060	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34											
35	**Maintenance**										
36	Maintenance Supervision	528	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37	Maintenance of Structures	529	-	-	-	-	-	-	-	-	-
38	Maintenance of Reactor Plant	530	-	-	-	-	-	-	-	-	-
39	Maintenance of Electric Plant	531	-	-	-	-	-	-	-	-	-
40	Maintenance of Miscellaneous	532	-	-	-	-	-	-	-	-	-
41			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42											
43	Hydraulic Power Generation										
44	**Maintenance**										
45	Maintenance Supervision	541	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Maintenance of Structures	542	-	-	-	-	-	-	-	-	-
47	Maintenance of Reservoirs, Dams & Waterways	543	-	-	-	-	-	-	-	-	-
48	Maintenance of Electric Plant	544	-	-	-	-	-	-	-	-	-
49	Maintenance of Miscellaneous Hydraulic Plant	545	-	-	-	-	-	-	-	-	-
50			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51											
52	Other Power Generation										
53	**Operation**										
54	Operation Supervision	546	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	Fuel	547	-	-	112,313,809	10,115,357	-	-	-	-	-
56	Generation Expenses	548	-	-	-	-	-	-	-	-	-
57	Miscellaneous Other Power Generation Expenses	549	-	-	-	-	-	-	-	-	-

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

			Energy Related								
Line No.		FERC Account	Base Load Nuclear - Fuel	Base Load Coal - Fuel	Intermediate Gas - Fuel	Peak Gas - Fuel	Economy Purch Pwr	Renewable Wind	Renewable Solar	Renewable LF Methane	Regulatory Adj Clause
A		B	K	L	M	N	O	P	Q	R	S
58	Rents	550	-	-	-	-	-	-	-	-	-
59	Energy Efficiency		-	-	-	-	-	-	-	-	-
60	Green Building		-	-	-	-	-	-	-	-	-
61	Solar Rebate		-	-	-	-	-	-	-	-	-
62			$ -	$ -	$ 112,313,809	$ 10,115,357	$ -	$ -	$ -	$ -	$ -
63											
64	**Maintenance**										
65	Maintenance Supervision and Engineering	551	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	Maintenance of Structures	552	-	-	-	-	-	-	-	-	-
67	Maintenance of Generating and Electric Equipment	553	-	-	-	-	-	-	-	-	-
68	Maintenance of Misc Other Power Generation Plant	554	-	-	-	-	-	-	-	-	-
69			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70											
71	Other Power Supply										
72	Purchased Power - Recoverable	555	$ -	$ -	$ -	$ -	$ 23,084,089	$ 58,628,188	$ 11,477,080	$ 3,322,545	$ -
73	Purchased Power - Non-Recoverable	555	-	-	-	-	-	346,133	-	-	-
74	System Control and Load Dispatching - Recoverable	556	587,479	3,326,598	4,077,770	307,156	700,955	1,790,808	348,505	100,890	9,839,798
75	System Control and Load Dispatching - Non-Recoverable	556	-	-	-	-	-	-	-	-	-
76	Other Power Expenses	557	-	-	-	-	-	-	-	-	-
77			$ 587,479	$ 3,326,598	$ 4,077,770	$ 307,156	$ 23,785,043	$ 60,765,129	$ 11,825,585	$ 3,423,435	$ 9,839,798
78											
79	**Total Power Production Expense**		**$ 19,934,539**	**$ 112,879,328**	**$ 138,368,338**	**$ 10,422,513**	**$ 23,785,043**	**$ 60,765,129**	**$ 11,825,585**	**$ 3,423,435**	**$ 9,839,798**
80											
101											
102	**Total Transmission Expenses**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
103											
129											
130	**Total Distribution Expenses**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
131											
132	**Customer and Information Expenses**										
151			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
152											
153	**Total Customer and Information Expenses**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
154											
155	**General and Administrative Expenses**										
156	Administrative and General Salaries	920	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
157	Office Supplies and Expenses	921	-	-	-	-	-	-	-	-	-
158	Administrative Expense Transferred	922	-	-	-	-	-	-	-	-	-
159	Outside Services Employed	923	-	-	-	-	-	-	-	-	-
160	Property Insurance	924	-	-	-	-	-	41	-	-	-
161	Injuries and Damages	925	-	-	-	-	-	-	-	-	-
162	Employee Pension and Benefits	926	-	-	-	-	-	-	-	-	-
163	Regulatory Commission Expense	928	19,627	111,136	136,231	10,262	23,418	59,828	11,643	3,371	-
164	General Expenses	930	-	-	-	-	-	-	-	-	-
165	Rents	931	-	-	-	-	-	-	-	-	-
166	Maintenance of General Plant	935	-	-	-	-	-	1	-	-	-
167			$ 19,627	$ 111,136	$ 136,231	$ 10,262	$ 23,418	$ 59,869	$ 11,643	$ 3,371	$ -
168											
169	**Total Operations & Maintenance Expenses**		**$ 19,954,165**	**$ 112,990,464**	**$ 138,504,569**	**$ 10,432,774**	**$ 23,808,461**	**$ 60,824,998**	**$ 11,837,228**	**$ 3,426,806**	**$ 9,839,798**
170											
171	**Depreciation & Amortization of CIAC**										
172	Depreciation Expense	403	$ -	$ -	$ -	$ -	$ -	$ 1,260	$ -	$ -	$ -
173	Amortization of CIAC		-	-	-	-	-	-	-	-	-
174			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,260**	**$ -**	**$ -**	**$ -**
175											
176	**Debt Service**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Energy Related: Base Load Nuclear - Fuel	Base Load Coal - Fuel	Intermediate Gas - Fuel	Peak Gas - Fuel	Economy Purch Pwr	Renewable Wind	Renewable Solar	Renewable LF Methane	Regulatory Adj Clause
A		B	K	L	M	N	O	P	Q	R	S
177											
178	**General Fund Transfer**	421.5	$ 2,130,944	$ 12,066,470	$ 14,791,170	$ 1,114,136	$ 2,542,552	$ 6,495,743	$ 1,264,120	$ 365,955	$ -
179											
180	**Margin**		$ -	$ -	$ -	$ -	$ -	$ (96)	$ -	$ -	$ -
181											
182	**Sub-Total Revenue Requirement**		$ 22,085,109	$ 125,056,934	$ 153,295,739	$ 11,546,911	$ 26,351,013	$ 67,321,905	$ 13,101,348	$ 3,792,761	$ 9,839,798
183											
184	**Other Expenses**										
185	Misc Service Revenue	451	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
186	Donations	426	-	-	-	-	-	-	-	-	-
187	Taxes Other Than Income	408	-	-	-	-	-	-	-	-	-
188	Expenses - Non-utility operations	417	-	-	-	-	-	-	-	-	-
189	Franchise Fees		-	-	-	-	-	-	-	-	-
190			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
191											
192	**Other (Non-Rate) Revenue**										
193	Miscellaneous Nonoperating Income	421	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
194	Other Revenue		-	-	-	-	-	-	-	-	-
195	Off-System Sales		-	-	-	-	-	-	-	-	-
196			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
197											
198	**Total Revenue Requirement**		$ 22,085,109	$ 125,056,934	$ 153,295,739	$ 11,546,911	$ 26,351,013	$ 67,321,905	$ 13,101,348	$ 3,792,761	$ 9,839,798
199											
200	**System Retail Sales (MWH)**										
201	Average Rate ($/MWh)										
202											
203											
204											
205	**Gross Plant In Service**										
212											
213	Steam Power Generation										
214	Land & Land Rights	310	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
215	Structures & Improvements	311	-	-	-	-	-	-	-	-	-
216	Boiler Plant Equipment	312	-	-	-	-	-	-	-	-	-
217	Engines and Engine Driven Generators	313	-	-	-	-	-	-	-	-	-
218	Turbogenerator Units	314	-	-	-	-	-	-	-	-	-
219	Accessory Plt Equipment	315	-	-	-	-	-	-	-	-	-
220	Miscellaneous Equipment	316	-	-	-	-	-	-	-	-	-
221			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
222											
223	Nuclear Power Generation										
224	Land & Land Rights	320	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
225	Structures & Improvements	321	-	-	-	-	-	-	-	-	-
226	Reactor Plant Equipment	322	-	-	-	-	-	-	-	-	-
227	Turbogenerator Units	323	-	-	-	-	-	-	-	-	-
228	Accessory Plant Equipment	324	-	-	-	-	-	-	-	-	-
229	Miscellaneous Equipment	325	-	-	-	-	-	-	-	-	-
230			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
231											
232	Combustion Turbine & Other Productior										
233	Land & Land Rights	340	$ -	$ -	$ -	$ -	$ -	$ 3	$ -	$ -	$ -
234	Structures & Improvements	341	-	-	-	-	-	661	-	-	-
235	Fuel Holders, Producers and Accessories	342	-	-	-	-	-	1,017	-	-	-
236	Prime movers	343	-	-	-	-	-	117	-	-	-
237	Generator/PV	344	-	-	-	-	-	36,517	-	-	-
238	Accessory Elec Equip.	345	-	-	-	-	-	310	-	-	-

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Energy Related: Base Load Nuclear - Fuel	Base Load Coal - Fuel	Intermediate Gas - Fuel	Peak Gas - Fuel	Economy Purch Pwr	Renewable Wind	Renewable Solar	Renewable LF Methane	Regulatory Adj Clause
A		B	K	L	M	N	O	P	Q	R	S
239	Miscellaneous Equipment	346	-	-	-	-	-	207	-	-	-
240			$ -	$ -	$ -	$ -	$ -	$ 38,832	$ -	$ -	$ -
241											
242	**Total Power Generation Plant**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 38,832**	**$ -**	**$ -**	**$ -**
243											
273											
274	**Subtotal Plant in Service Before General Plant**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 38,832**	**$ -**	**$ -**	**$ -**
275											
276	General Plant										
277	Land & Land Rights	389	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
278	Structures & Improvements	390	-	-	-	-	-	-	-	-	-
279	Office Furniture & Equipment	391	-	-	-	-	-	-	-	-	-
280	Transportation Equipment	392	-	-	-	-	-	-	-	-	-
281	Stores Equipment	393	-	-	-	-	-	-	-	-	-
282	Tools, Shop & Garage Equipment	394	-	-	-	-	-	-	-	-	-
283	Laboratory Equipment	395	-	-	-	-	-	-	-	-	-
284	Power Operated Equipment	396	-	-	-	-	-	-	-	-	-
285	Communications Equipment	397	-	-	-	-	-	-	-	-	-
286	Miscellaneous Equipment	398	-	-	-	-	-	-	-	-	-
287	Other Tangible Property	399	-	-	-	-	-	-	-	-	-
288			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
289											
290	**Total Plant in Service - Gross**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 38,832**	**$ -**	**$ -**	**$ -**
291											
292											
293											
294	**Accumulated Depreciation**										
301											
302	Steam Power Generation										
303	Land & Land Rights	310	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
304	Structures & Improvements	311	-	-	-	-	-	-	-	-	-
305	Boiler Plant Equipment	312	-	-	-	-	-	-	-	-	-
306	Engines and Engine Driven Generators	313	-	-	-	-	-	-	-	-	-
307	Turbogenerator Units	314	-	-	-	-	-	-	-	-	-
308	Accessory Plt Equipment	315	-	-	-	-	-	-	-	-	-
309	Miscellaneous Equipment	316	-	-	-	-	-	-	-	-	-
310			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311											
312	Nuclear Power Generation										
313	Land & Land Rights	320	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
314	Structures & Improvements	321	-	-	-	-	-	-	-	-	-
315	Reactor Plant Equipment	322	-	-	-	-	-	-	-	-	-
316	Turbogenerator Units	323	-	-	-	-	-	-	-	-	-
317	Accessory Plant Equipment	324	-	-	-	-	-	-	-	-	-
318	Miscellaneous Equipment	325	-	-	-	-	-	-	-	-	-
319			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
320											
321	Combustion Turbine & Other Productior										
322	Land & Land Rights	340	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
323	Structures & Improvements	341	-	-	-	-	-	84	-	-	-
324	Fuel Holders, Producers and Accessories	342	-	-	-	-	-	201	-	-	-
325	Prime movers	343	-	-	-	-	-	28	-	-	-
326	Generator/PV	344	-	-	-	-	-	9,611	-	-	-
327	Accessory Elec Equip.	345	-	-	-	-	-	99	-	-	-
328	Miscellaneous Equipment	346	-	-	-	-	-	34	-	-	-
329			$ -	$ -	$ -	$ -	$ -	$ 10,057	$ -	$ -	$ -

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Energy Related Base Load Nuclear - Fuel	Base Load Coal - Fuel	Intermediate Gas - Fuel	Peak Gas - Fuel	Economy Purch Pwr	Renewable Wind	Renewable Solar	Renewable LF Methane	Regulatory Adj Clause
A		B	K	L	M	N	O	P	Q	R	S
330											
331	**Total Power Generation Plant**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 10,057**	**$ -**	**$ -**	**$ -**
332											
362											
363	**Subtotal Plant in Service Before General Plant**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 10,057**	**$ -**	**$ -**	**$ -**
364											
365	General Plant										
366	Land & Land Rights	389	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
367	Structures & Improvements	390	-	-	-	-	-	-	-	-	-
368	Office Furniture & Equipment	391	-	-	-	-	-	-	-	-	-
369	Transportation Equipment	392	-	-	-	-	-	-	-	-	-
370	Stores Equipment	393	-	-	-	-	-	-	-	-	-
371	Tools, Shop & Garage Equipment	394	-	-	-	-	-	-	-	-	-
372	Laboratory Equipment	395	-	-	-	-	-	-	-	-	-
373	Power Operated Equipment	396	-	-	-	-	-	-	-	-	-
374	Communications Equipment	397	-	-	-	-	-	-	-	-	-
375	Miscellaneous Equipment	398	-	-	-	-	-	-	-	-	-
376	Other Tangible Property	399	-	-	-	-	-	-	-	-	-
377			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
378											
379	**Total Plant in Service - Accumulated Depreciation**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 10,057**	**$ -**	**$ -**	**$ -**
380											
381											
382											
383	**Net Plant In Service**										
390											
391	Steam Power Generation										
392	Land & Land Rights	310	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
393	Structures & Improvements	311	-	-	-	-	-	-	-	-	-
394	Boiler Plant Equipment	312	-	-	-	-	-	-	-	-	-
395	Engines and Engine Driven Generators	313	-	-	-	-	-	-	-	-	-
396	Turbogenerator Units	314	-	-	-	-	-	-	-	-	-
397	Accessory Plt Equipment	315	-	-	-	-	-	-	-	-	-
398	Miscellaneous Equipment	316	-	-	-	-	-	-	-	-	-
399			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
400											
401	Nuclear Power Generation										
402	Land & Land Rights	320	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
403	Structures & Improvements	321	-	-	-	-	-	-	-	-	-
404	Reactor Plant Equipment	322	-	-	-	-	-	-	-	-	-
405	Turbogenerator Units	323	-	-	-	-	-	-	-	-	-
406	Accessory Plant Equipment	324	-	-	-	-	-	-	-	-	-
407	Miscellaneous Equipment	325	-	-	-	-	-	-	-	-	-
408			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
409											
410	Combustion Turbine & Other Productior										
411	Land & Land Rights	340	$ -	$ -	$ -	$ -	$ -	$ 3	$ -	$ -	$ -
412	Structures & Improvements	341	-	-	-	-	-	556	-	-	-
413	Fuel Holders, Producers and Accessories	342	-	-	-	-	-	802	-	-	-
414	Prime movers	343	-	-	-	-	-	88	-	-	-
415	Generator/PV	344	-	-	-	-	-	26,941	-	-	-
416	Accessory Elec Equip.	345	-	-	-	-	-	215	-	-	-
417	Miscellaneous Equipment	346	-	-	-	-	-	169	-	-	-
418			$ -	$ -	$ -	$ -	$ -	$ 28,774	$ -	$ -	$ -
419											
420	**Total Power Generation Plant**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 28,774**	**$ -**	**$ -**	**$ -**

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Production

Line No.		FERC Account	Energy Related Base Load Nuclear - Fuel	Base Load Coal - Fuel	Intermediate Gas - Fuel	Peak Gas - Fuel	Economy Purch Pwr	Renewable Wind	Renewable Solar	Renewable LF Methane	Regulatory Adj Clause
A		B	K	L	M	N	O	P	Q	R	S
421											
451											
452	**Subtotal Plant in Service Before General Plant**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 28,774**	**$ -**	**$ -**	**$ -**
453											
454	General Plant										
455	Land & Land Rights	389	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
456	Structures & Improvements	390	-	-	-	-	-	-	-	-	-
457	Office Furniture & Equipment	391	-	-	-	-	-	-	-	-	-
458	Transportation Equipment	392	-	-	-	-	-	-	-	-	-
459	Stores Equipment	393	-	-	-	-	-	-	-	-	-
460	Tools, Shop & Garage Equipment	394	-	-	-	-	-	-	-	-	-
461	Laboratory Equipment	395	-	-	-	-	-	-	-	-	-
462	Power Operated Equipment	396	-	-	-	-	-	-	-	-	-
463	Communications Equipment	397	-	-	-	-	-	-	-	-	-
464	Miscellaneous Equipment	398	-	-	-	-	-	-	-	-	-
465	Other Tangible Property	399	-	-	-	-	-	-	-	-	-
466			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
467											
468	**Total Plant in Service - Net**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 28,774**	**$ -**	**$ -**	**$ -**
469											
470											
471											
472	**Depreciation Expense**										
479											
480	Steam Power Generation										
481	Land & Land Rights	310	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
482	Structures & Improvements	311	-	-	-	-	-	-	-	-	-
483	Boiler Plant Equipment	312	-	-	-	-	-	-	-	-	-
484	Engines and Engine Driven Generators	313	-	-	-	-	-	-	-	-	-
485	Turbogenerator Units	314	-	-	-	-	-	-	-	-	-
486	Accessory Plt Equipment	315	-	-	-	-	-	-	-	-	-
487	Miscellaneous Equipment	316	-	-	-	-	-	-	-	-	-
488			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
489											
490	Nuclear Power Generation										
491	Land & Land Rights	320	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
492	Structures & Improvements	321	-	-	-	-	-	-	-	-	-
493	Reactor Plant Equipment	322	-	-	-	-	-	-	-	-	-
494	Turbogenerator Units	323	-	-	-	-	-	-	-	-	-
495	Accessory Plant Equipment	324	-	-	-	-	-	-	-	-	-
496	Miscellaneous Equipment	325	-	-	-	-	-	-	-	-	-
497			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
498											
499	Combustion Turbine & Other Production										
500	Land & Land Rights	340	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
501	Structures & Improvements	341	-	-	-	-	-	21	-	-	-
502	Fuel Holders, Producers and Accessories	342	-	-	-	-	-	33	-	-	-
503	Prime movers	343	-	-	-	-	-	4	-	-	-
504	Generator/PV	344	-	-	-	-	-	1,185	-	-	-
505	Accessory Elec Equip.	345	-	-	-	-	-	10	-	-	-
506	Miscellaneous Equipment	346	-	-	-	-	-	7	-	-	-
507			$ -	$ -	$ -	$ -	$ -	$ 1,260	$ -	$ -	$ -
508											
509	**Total Power Generation Plant**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,260**	**$ -**	**$ -**	**$ -**
510											
540											

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

			Energy Related								
Line No.		FERC Account	Base Load Nuclear - Fuel	Base Load Coal - Fuel	Intermediate Gas - Fuel	Peak Gas - Fuel	Economy Purch Pwr	Renewable Wind	Renewable Solar	Renewable LF Methane	Regulatory Adj Clause
A		B	K	L	M	N	O	P	Q	R	S
541	**Subtotal Plant in Service Before General Plant**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,260**	**$ -**	**$ -**	**$ -**
542											
543	General Plant										
544	Land & Land Rights	389	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
545	Structures & Improvements	390	-	-	-	-	-	-	-	-	-
546	Office Furniture & Equipment	391	-	-	-	-	-	-	-	-	-
547	Transportation Equipment	392	-	-	-	-	-	-	-	-	-
548	Stores Equipment	393	-	-	-	-	-	-	-	-	-
549	Tools, Shop & Garage Equipment	394	-	-	-	-	-	-	-	-	-
550	Laboratory Equipment	395	-	-	-	-	-	-	-	-	-
551	Power Operated Equipment	396	-	-	-	-	-	-	-	-	-
552	Communications Equipment	397	-	-	-	-	-	-	-	-	-
553	Miscellaneous Equipment	398	-	-	-	-	-	-	-	-	-
554	Other Tangible Property	399	-	-	-	-	-	-	-	-	-
555			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
556											
557	**Total Plant Depreciation**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,260**	**$ -**	**$ -**	**$ -**
558											
559											
560											
561											
562											
563	**Labor**										
564											
565	**Power Production Expenses**										
566	Steam Power Generation										
567	**Operation**										
568	Operation Supervision and Engineering	500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
569	Fuel	501	-	-	-	-	-	-	-	-	-
570	Steam Expenses	502	-	-	-	-	-	-	-	-	-
571	Steam from other Sources	503	-	-	-	-	-	-	-	-	-
572	Steam Transferred	504	-	-	-	-	-	-	-	-	-
573	Electric Expenses	505	-	-	-	-	-	-	-	-	-
574	Miscellaneous Steam Expenses	506	-	-	-	-	-	-	-	-	-
575	Rents	507	-	-	-	-	-	-	-	-	-
576			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
577											
578	**Maintenance**										
579	Maintenance Supervision	510	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
580	Maintenance of Structures	511	-	-	-	-	-	-	-	-	-
581	Maintenance of Boiler Plant	512	-	-	-	-	-	-	-	-	-
582	Maintenance of Electric Plant	513	-	-	-	-	-	-	-	-	-
583	Maintenance of Miscellaneous Steam Plant	514	-	-	-	-	-	-	-	-	-
584	Rents	515	-	-	-	-	-	-	-	-	-
585			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
586											
587	Nuclear Power Generation										
588	**Operation**										
589	Operation Supervision	517	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
590	Nuclear Fuel Expense	518	-	-	-	-	-	-	-	-	-
591	Coolants and Water	519	-	-	-	-	-	-	-	-	-
592	Steam Expenses	520	-	-	-	-	-	-	-	-	-
593	Electric Expenses	523	-	-	-	-	-	-	-	-	-
594	Misc Nuclear Power Expenses	524	-	-	-	-	-	-	-	-	-
595	Rents	525	-	-	-	-	-	-	-	-	-
596			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

			Energy Related								
Line No.		FERC Account	Base Load Nuclear - Fuel	Base Load Coal - Fuel	Intermediate Gas - Fuel	Peak Gas - Fuel	Economy Purch Pwr	Renewable Wind	Renewable Solar	Renewable LF Methane	Regulatory Adj Clause
A		B	K	L	M	N	O	P	Q	R	S
597											
598	**Maintenance**										
599	Maintenance Supervision	528	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
600	Maintenance of Structures	529	-	-	-	-	-	-	-	-	-
601	Maintenance of Reactor Plant	530	-	-	-	-	-	-	-	-	-
602	Maintenance of Electric Plant	531	-	-	-	-	-	-	-	-	-
603	Maintenance of Miscellaneous	532	-	-	-	-	-	-	-	-	-
604			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
605											
606	Hydraulic Power Generation										
607	**Maintenance**										
608	Maintenance Supervision	541	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
609	Maintenance of Structures	542	-	-	-	-	-	-	-	-	-
610	Maintenance of Reservoirs, Dams & Waterways	543	-	-	-	-	-	-	-	-	-
611	Maintenance of Electric Plant	544	-	-	-	-	-	-	-	-	-
612	Maintenance of Miscellaneous Hydraulic Plant	545	-	-	-	-	-	-	-	-	-
613			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
614											
615	Other Power Generation										
616	**Operation**										
617	Operation Supervision	546	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
618	Fuel	547	-	-	-	-	-	-	-	-	-
619	Generation Expenses	548	-	-	-	-	-	-	-	-	-
620	Miscellaneous Other Power Generation Expenses	549	-	-	-	-	-	-	-	-	-
621	Rents	550	-	-	-	-	-	-	-	-	-
622			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
623											
624	**Maintenance**										
625	Maintenance Supervision and Engineering	551	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
626	Maintenance of Structures	552	-	-	-	-	-	-	-	-	-
627	Maintenance of Generating and Electric Equipment	553	-	-	-	-	-	-	-	-	-
628	Maintenance of Misc Other Power Generation Plant	554	-	-	-	-	-	-	-	-	-
629			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
630											
631	Other Power Supply										
632	Purchased Power	555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
633	System Control and Load Dispatching	556	-	-	-	-	-	-	-	-	-
634	Other Power Expenses	557	-	-	-	-	-	-	-	-	-
635			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
636											
637	**Total Power Production Expense**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
638											
659											
660	**Total Transmission Expenses**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
661											
687											
688	**Total Distribution Expenses**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
689											
710											
711	**Total Customer and Information Expenses**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
712											
713	**General and Administrative Expenses**										
714	Administrative and General Salaries	920	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
715	Office Supplies and Expenses	921	-	-	-	-	-	-	-	-	-
716	Administrative Expense Transferred	922	-	-	-	-	-	-	-	-	-
717	Outside Services Employed	923	-	-	-	-	-	-	-	-	-

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

				Energy Related								
Line No.			FERC Account	Base Load Nuclear - Fuel	Base Load Coal - Fuel	Intermediate Gas - Fuel	Peak Gas - Fuel	Economy Purch Pwr	Renewable Wind	Renewable Solar	Renewable LF Methane	Regulatory Adj Clause
A			B	K	L	M	N	O	P	Q	R	S
718		Property Insurance	924	-	-	-	-	-	-	-	-	-
719		Injuries and Damages	925	-	-	-	-	-	-	-	-	-
720		Employee Pension and Benefits	926	-	-	-	-	-	-	-	-	-
721		Regulatory Commission Expense	928	-	-	-	-	-	-	-	-	-
722		General Expenses	930	-	-	-	-	-	-	-	-	-
723		Rents	931	-	-	-	-	-	-	-	-	-
724		Maintenance of General Plant	935	-	-	-	-	-	-	-	-	-
725				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
726												
727	**Total Electric Labor**			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
728												
729												
730												
731	**Allocation Factors**											
732	1	Regulatory		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
733		Direct Assignment to Regulatory Clause										1
734												
735	2	Community Benefit		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
736		Direct Assignment to Community Benefit Clause										
737												
738	3	FERC 513	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
739		Steam Generation FERC 513										
740												
741	4	FERC 514	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
742		Steam Generation FERC 514										
743												
744	5	556 Non-Recoverable	WP 44 - PCF	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
745		Direct Assignment to Green Choice and Remainder to Demand Relat		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
746		Other FERC 556 Non-Recoverable to Production Demand Related Re		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
747		FERC 556 Non-Recoverable Direct to Green Choice		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
748												
749	6	555 Non-Recoverable	WP 44 - PCF	0.0%	0.0%	0.0%	0.0%	0.0%	3.3%	0.0%	0.0%	0.0%
750		Direct Assignments to GC and Remainder to Demand Related Wind (		$ -	$ -	$ -	$ -	$ -	$ 346,133	$ -	$ -	$ -
751		Direct Assignment to Green Choice		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
752		Other Non-Recoverable FERC 555 Allocated to Energy Related Winc		$ -	$ -	$ -	$ -	$ -	$ 346,133	$ -	$ -	$ -
753												
754	7	Prod RR - Demand		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
755		Revenue Requirement Associated with Demand Related Generation										
756												
757	8	Steam Fuel	WP 44 - PCF	0.0%	83.3%	16.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
758		Steam Generation Fuel for Base Load and Intermediate			109,552,730	21,976,759						
759												
760	9	Nuclear DA		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
761		Direct Assignment to Demand Related Nuclear Generation										
762												
763	10	Nuclear Fuel	WP 44 - PCF	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
764		Nuclear Generation Fuel for Base Load Resource Type		19,347,060								
765												
766	11	T Prod Plant - Depr		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
767		Total Depreciation for Production Plant In Service, Including General		-	-	-	-	-	1,260	-	-	-
768												
769	12	Other Fuel	WP 44 - PCF	0.0%	0.0%	91.7%	8.3%	0.0%	0.0%	0.0%	0.0%	0.0%
770		Other Generation Fuel for Intermediate and Peak				112,313,809	10,115,357					
771												
772	13	FERC 500	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
773		Steam Generation FERC 500										
774												

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line			FERC	Energy Related								
				Base Load	Base Load	Intermediate	Peak	Economy	Renewable	Renewable	Renewable	Regulatory
No.			Account	Nuclear - Fuel	Coal - Fuel	Gas - Fuel	Gas - Fuel	Purch Pwr	Wind	Solar	LF Methane	Adj Clause
A			B	K	L	M	N	O	P	Q	R	S
775	14	FERC 502	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
776		Steam Generation FERC 502										
777												
778	15	FERC 505	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
779		Steam Generation FERC 505										
780												
781	16	FERC 506	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
782		Steam Generation FERC 506										
783												
784	17	FERC 510	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
785		Steam Generation FERC 510										
786												
787	18	FERC 511	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
788		Steam Generation FERC 511										
789												
790	19	FERC 512	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
791		Steam Generation FERC 512										
792												
793	20	Prod RR		2.9%	16.6%	20.3%	1.5%	3.5%	8.9%	1.7%	0.5%	0.0%
794		Generation Revenue Requirement, Excluding DA to Regulatory and C		22,085,109	125,056,934	153,295,739	11,546,911	26,351,013	67,321,905	13,101,348	3,792,761	
795												
796	21	Prod 920	WP 6 - G&A	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
797		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Ex		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
798		FERC 920 STP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
799		FERC 920 FPP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
800		Other Allocated FERC 920 to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801												
802	22	Prod 921	WP 6 - G&A	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
803		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Ex		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
804		FERC 921 STP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
805		FERC 921 FPP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
806		Other Allocated FERC 921 to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
807												
808	23	Prod Labor		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
809		Total Production Labor, Excluding G&A and DA to Regulatory and Co		-	-	-	-	-	-	-	-	
810												
811	24	Prod 923	WP 6 - G&A	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
812		Based on Direct Allocations in WP 6 - G&A and Total Production O&M		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
813		FERC 923 STP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
814		FERC 923 FPP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
815		Other Allocated FERC 923 to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
816												
817	25	Prod 924	WP 6 - G&A	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
818		Based on Direct Allocations in WP 6 - G&A and Generation Net Plant		$ -	$ -	$ -	$ -	$ -	$ 41	$ -	$ -	$ -
819		FERC 924 STP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
820		FERC 924 FPP and Boiler Insurance Direct to Productior		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
821		Other Allocated FERC 924 to Production		$ -	$ -	$ -	$ -	$ -	$ 41	$ -	$ -	$ -
822												
823	26	Prod 925	WP 6 - G&A	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
824		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Ex		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
825		FERC 925 STP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
826		FERC 925 FPP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
827		Other Allocated FERC 925 to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
828												
829	27	Prod 926	WP 6 - G&A	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
830		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Ex		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
831		FERC 926 STP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.			FERC Account	Energy Related Base Load Nuclear - Fuel	Base Load Coal - Fuel	Intermediate Gas - Fuel	Peak Gas - Fuel	Economy Purch Pwr	Renewable Wind	Renewable Solar	Renewable LF Methane	Regulatory Adj Clause
A			B	K	L	M	N	O	P	Q	R	S
832		FERC 926 FPP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
833		Other Allocated FERC 926 to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
834												
835	28	Prod 930	WP 6 - G&A	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
836		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Ex		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
837		FERC 930 STP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
838		FERC 930 FPP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
839		Other Allocated FERC 930 to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
840												
841	29	Prod 935	WP 6 - G&A	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
842		Based on Direct Allocations in WP 6 - G&A and Generation Net Plant		$ -	$ -	$ -	$ -	$ -	$ 1	$ -	$ -	$ -
843		FERC 935 STP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
844		FERC 935 FPP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
845		Other Allocated FERC 935 to Production		$ -	$ -	$ -	$ -	$ -	$ 1	$ -	$ -	$ -
846												
847	30	555 Recoverable	WP 44 - PCF	0.0%	0.0%	0.0%	0.0%	23.9%	60.7%	11.9%	3.4%	0.0%
848		Direct Assignments of FERC 555 Recoverable		$ -	$ -	$ -	$ -	$ 23,084,089	$ 58,628,188	$ 11,477,080	$ 3,322,545	$ -
849		FERC 555 Recoverable Direct to Economy Purchase Power		$ -	$ -	$ -	$ -	$ 23,084,089	$ -	$ -	$ -	$ -
850		FERC 555 Recoverable Direct to Wind		$ -	$ -	$ -	$ -	$ -	$ 58,628,188	$ -	$ -	$ -
851		FERC 555 Recoverable Direct to Landfill Methane		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,322,545	$ -
852		FERC 555 Recoverable Direct to Solar		$ -	$ -	$ -	$ -	$ -	$ -	$ 11,477,080	$ -	$ -
853												
854	31	556 Recoverable	WP 28.1 - F	2.8%	15.8%	19.3%	1.5%	3.3%	8.5%	1.7%	0.5%	46.7%
855		Direct Assignments of FERC 556 Recoverable to Regulatory Clause		$ 587,479	$ 3,326,598	$ 4,077,770	$ 307,156	$ 700,955	$ 1,790,808	$ 348,505	$ 100,890	$ 9,839,798
856		FERC 556 Recoverable Direct to Regulatory		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,839,798
857		Allocation to Demand Related Revenue Requirement		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
858		Allocation to Energy Related Revenue Requirement		$ 587,479	$ 3,326,598	$ 4,077,770	$ 307,156	$ 700,955	$ 1,790,808	$ 348,505	$ 100,890	$ -
859												
860	32	Prod Debt Service	WP 5.3 - De	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
861		Sub-functionalization of Debt Service Based on Detailed Allocation o										
862												
863	33	Steam Plant - G	WP 26 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
864												
865												
866	34	Steam Plant - AD	WP 26 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
867												
868												
869	35	Steam Plant - Depr	WP 26 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
870												
871												
872	36	Steam Plant - Net	WP 26 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
873												
874												
875	37	Other Gen Plant - G	WP 26 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
876									38,900			
877												
878	38	Other Gen Plant - AD	WP 26 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
879									10,078			
880												
881	39	Other Gen Plant - Depr	WP 26 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
882									1,262			
883												
884	40	Other Gen Plant - Net	WP 26 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
885									28,822			
886												
887	41	Prod RR - Energy		5.2%	29.6%	36.3%	2.7%	6.2%	15.9%	3.1%	0.9%	0.0%
888		Revenue Requirement Associated with Energy Related Generation		22,085,109	125,056,934	153,295,739	11,546,911	26,351,013	67,321,905	13,101,348	3,792,761	

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.			FERC Account	Energy Related Base Load Nuclear - Fuel	 Base Load Coal - Fuel	 Intermediate Gas - Fuel	 Peak Gas - Fuel	 Economy Purch Pwr	 Renewable Wind	 Renewable Solar	 Renewable LF Methane	 Regulatory Adj Clause
A			B	K	L	M	N	O	P	Q	R	S
889												
890	42	Prod Plant - Net	WP 26 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
891		Net Production Plant In Service (excluding General Plant)							28,822			
892												
893	43	FERC 546	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
894		Other Power Generation FERC 546										
895												
896	44	FERC 548	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
897		Other Power Generation FERC 548										
898												
899	45	FERC 549	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
900		Other Power Generation FERC 549										
901												
902	46	FERC 550	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
903		Other Power Generation FERC 550										
904												
905	47	FERC 551	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
906		Other Power Generation FERC 551										
907												
908	48	FERC 552	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
909		Other Power Generation FERC 552										
910												
911	49	FERC 553	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
912		Other Power Generation FERC 553										
913												
914	50	FERC 554	WP 24 - Pro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
915		Other Power Generation FERC 554										
916												
917	51	Prod 931	WP 6 - G&A	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
918		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Ex		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
919		FERC 931 STP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
920		FERC 931 FPP Direct to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
921		Other Allocated FERC 931 to Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
922												
923	52	Prod O&M EXAGF		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
924		Total Production O&M, Excluding G&A, Commodity Fuel and Purcha:										
925												
926	53	Base Coal DA		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
927		Direct Assignment to Demand Related Base Load Coal Generation										
928												
929	54	Green Choice DA		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
930		Direct Assignment to Green Choice										
931												
932	55	501 Non-Recoverable	WP 44 - PCF	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
933		Allocation of FERC 501 Non-Recoverable Based on Steam Fuel Expen		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
934				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
935				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
936												
937	56	Solar Energy DA		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%
938		Direct Assignment of Solar to Energy								1		
939												
940	57	Wind Energy DA		0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%
941		Direct Assignment of Wind to Energy							1			
942												
943	58	Econ PP DA		0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
944		Direct Assignment of Economy Purchase Power to Energy						1				
945												

Test Year Revenue Requirement - Production
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.			FERC Account	Energy Related: Base Load Nuclear - Fuel	Base Load Coal - Fuel	Intermediate Gas - Fuel	Peak Gas - Fuel	Economy Purch Pwr	Renewable Wind	Renewable Solar	Renewable LF Methane	Regulatory Adj Clause
A			B	K	L	M	N	O	P	Q	R	S
946	61	Int Gas DA		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
947		Direct Assignment to Intermediate Gas										
948												
949	62	Peak Gas DA		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
950		Direct Assignment to Peak Gas										
951												
952	63	LF Gas Energy DA		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
953		Direct Assignment of Landfill Methane to Energy									1	

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Direct Assignments Community Benefit Adj Clause	Direct Assignments Green Choice	Total
A		B	T	U	V
1	**Power Production Expenses**				
2	Steam Power Generation				
3	**Operation**				
4	Operation Supervision and Engineering	500	$ -	$ -	$ 7,911,687
5	Fuel - Recoverable	501	-	-	131,529,489
6	Fuel - Non-Recoverable	501	-	-	4,944,942
7	Steam Expenses	502	-	-	6,346,996
8	Steam from other Sources	503	-	-	-
9	Steam Transferred	504	-	-	-
10	Electric Expenses	505	-	-	1,700,950
11	Miscellaneous Steam Expenses	506	-	-	4,199,234
12	Rents	507	-	-	-
13			$ -	$ -	$ 156,633,297
14					
15	**Maintenance**				
16	Maintenance Supervision	510	$ -	$ -	$ 2,456,738
17	Maintenance of Structures	511	-	-	227,254
18	Maintenance of Boiler Plant	512	-	-	5,798,568
19	Maintenance of Electric Plant	513	-	-	3,022,679
20	Maintenance of Miscellaneous Steam Plant	514	-	-	3,655,717
21	Rents	515	-	-	-
22			$ -	$ -	$ 15,160,958
23					
24	Nuclear Power Generation				
25	**Operation**				
26	Operation Supervision	517	$ -	$ -	$ 8,927,390
27	Nuclear Fuel Expense	518	-	-	19,347,060
28	Coolants and Water	519	-	-	1,037,009
29	Steam Expenses	520	-	-	1,960,827
30	Electric Expenses	523	-	-	4,325,651
31	Misc Nuclear Power Expenses	524	-	-	13,103,665
32	Rents	525	-	-	-
33			$ -	$ -	$ 48,701,602
34					
35	**Maintenance**				
36	Maintenance Supervision	528	$ -	$ -	$ 6,051,042
37	Maintenance of Structures	529	-	-	2,688,726
38	Maintenance of Reactor Plant	530	-	-	7,144,179
39	Maintenance of Electric Plant	531	-	-	3,565,883
40	Maintenance of Miscellaneous	532	-	-	748,640
41			$ -	$ -	$ 20,198,469
42					
43	Hydraulic Power Generation				
44	**Maintenance**				
45	Maintenance Supervision	541	$ -	$ -	$ -
46	Maintenance of Structures	542	-	-	-
47	Maintenance of Reservoirs, Dams & Waterways	543	-	-	-
48	Maintenance of Electric Plant	544	-	-	-
49	Maintenance of Miscellaneous Hydraulic Plant	545	-	-	-
50			$ -	$ -	$ -
51					
52	Other Power Generation				
53	**Operation**				
54	Operation Supervision	546	$ -	$ -	$ 2,500,579
55	Fuel	547	-	-	122,429,167
56	Generation Expenses	548	-	-	4,057,389
57	Miscellaneous Other Power Generation Expenses	549	-	-	333,592

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Direct Assignments: Community Benefit Adj Clause	Direct Assignments: Green Choice	Total
A		B	T	U	V
58	Rents	550	-	-	205,206
59	Energy Efficiency		21,485,378	-	21,485,378
60	Green Building		1,881,981	-	1,881,981
61	Solar Rebate		4,352,770	-	4,352,770
62			$ 27,720,129	$ -	$ 157,246,061
63					
64	**Maintenance**				
65	Maintenance Supervision and Engineering	551	$ -	$ -	$ 43,213
66	Maintenance of Structures	552	-	-	147,578
67	Maintenance of Generating and Electric Equipment	553	-	-	13,253,125
68	Maintenance of Misc Other Power Generation Plant	554	-	-	1,443,910
69			$ -	$ -	$ 14,887,826
70					
71	Other Power Supply				
72	Purchased Power - Recoverable	555	$ -	$ -	$ 96,511,902
73	Purchased Power - Non-Recoverable	555	-	10,057,082	10,403,215
74	System Control and Load Dispatching - Recoverable	556	-	-	21,079,958
75	System Control and Load Dispatching - Non-Recoverable	556	-	-	1,802,970
76	Other Power Expenses	557	-	-	489,793
77			$ -	$ 10,057,082	$ 130,287,838
78					
79	**Total Power Production Expense**		**$ 27,720,129**	**$ 10,057,082**	**$ 543,116,051**
80					
101					
102	**Total Transmission Expenses**		**$ -**	**$ -**	**$ -**
103					
129					
130	**Total Distribution Expenses**		**$ -**	**$ -**	**$ -**
131					
132	**Customer and Information Expenses**				
151			$ -	$ -	$ -
152					
153	**Total Customer and Information Expenses**		**$ -**	**$ -**	**$ -**
154					
155	**General and Administrative Expenses**				
156	Administrative and General Salaries	920	$ -	$ -	$ 8,849,743
157	Office Supplies and Expenses	921	-	-	5,273,986
158	Administrative Expense Transferred	922	-	-	11,300
159	Outside Services Employed	923	-	-	5,754,009
160	Property Insurance	924	-	-	2,258,015
161	Injuries and Damages	925	-	-	1,097,461
162	Employee Pension and Benefits	926	-	-	9,931,952
163	Regulatory Commission Expense	928	-	-	670,167
164	General Expenses	930	-	-	6,524,359
165	Rents	931	-	-	562,234
166	Maintenance of General Plant	935	-	-	895,159
167			$ -	$ -	$ 41,828,385
168					
169	**Total Operations & Maintenance Expenses**		**$ 27,720,129**	**$ 10,057,082**	**$ 584,944,436**
170					
171	**Depreciation & Amortization of CIAC**				
172	Depreciation Expense	403	$ -	$ -	$ 60,991,236
173	Amortization of CIAC		-	-	-
174			**$ -**	**$ -**	**$ 60,991,236**
175					
176	**Debt Service**		**$ -**	**$ -**	**$ 88,022,271**

Test Year Revenue Requirement - Production
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Direct Assignments: Community Benefit Adj Clause	Direct Assignments: Green Choice	Total
A		B	T	U	V
177					
178	**General Fund Transfer**	421.5	$ -	$ -	**$ 72,762,791**
179					
180	**Margin**		$ -	$ -	**$ (4,641,370)**
181					
182	**Sub-Total Revenue Requirement**		**$ 27,720,129**	**$ 10,057,082**	**$ 802,079,364**
183					
184	**Other Expenses**				
185	Misc Service Revenue	451	$ -	$ -	$ 29,409
186	Donations	426	-	-	41,353
187	Taxes Other Than Income	408	-	-	18,736
188	Expenses - Non-utility operations	417	-	-	252,602
189	Franchise Fees		-	-	-
190			**$ -**	**$ -**	**$ 342,100**
191					
192	**Other (Non-Rate) Revenue**				
193	Miscellaneous Nonoperating Income	421	$ -	$ -	$ 2,684
194	Other Revenue		-	-	687,951
195	Off-System Sales		-	-	-
196			**$ -**	**$ -**	**$ 690,634**
197					
198	**Total Revenue Requirement**		**$ 27,720,129**	**$ 10,057,082**	**$ 801,730,829**
199					
200	**System Retail Sales (MWH)**				
201	Average Rate ($/MWh)				
202					
203					
204					
205	**Gross Plant In Service**				
212					
213	Steam Power Generation				
214	Land & Land Rights	310	$ -	$ -	$ 9,234,828
215	Structures & Improvements	311	-	-	89,448,743
216	Boiler Plant Equipment	312	-	-	411,835,651
217	Engines and Engine Driven Generators	313	-	-	-
218	Turbogenerator Units	314	-	-	75,657,814
219	Accessory Plt Equipment	315	-	-	30,715,062
220	Miscellaneous Equipment	316	-	-	62,763,111
221			$ -	$ -	$ 679,655,210
222					
223	Nuclear Power Generation				
224	Land & Land Rights	320	$ -	$ -	$ 2,782,002
225	Structures & Improvements	321	-	-	406,719,894
226	Reactor Plant Equipment	322	-	-	293,509,807
227	Turbogenerator Units	323	-	-	48,391,775
228	Accessory Plant Equipment	324	-	-	166,596,149
229	Miscellaneous Equipment	325	-	-	8,654,263
230			$ -	$ -	$ 926,653,891
231					
232	Combustion Turbine & Other Productior				
233	Land & Land Rights	340	$ -	$ -	$ 32,120
234	Structures & Improvements	341	-	-	6,738,057
235	Fuel Holders, Producers and Accessories	342	-	-	10,373,600
236	Prime movers	343	-	-	1,190,306
237	Generator/PV	344	-	-	372,495,368
238	Accessory Elec Equip.	345	-	-	3,162,172

Test Year Revenue Requirement - Production
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Direct Assignments Community Benefit Adj Clause	Green Choice	Total
A		B	T	U	V
239	Miscellaneous Equipment	346	-	-	2,114,443
240			$ -	$ -	$ 396,106,067
241					
242	**Total Power Generation Plant**		**$ -**	**$ -**	**$ 2,002,415,168**
243					
273					
274	**Subtotal Plant in Service Before General Plant**		**$ -**	**$ -**	**$ 2,002,415,168**
275					
276	General Plant				
277	Land & Land Rights	389	$ -	$ -	$ 10,776,642
278	Structures & Improvements	390	-	-	28,502,655
279	Office Furniture & Equipment	391	-	-	16,996,420
280	Transportation Equipment	392	-	-	1,849,619
281	Stores Equipment	393	-	-	321,151
282	Tools, Shop & Garage Equipment	394	-	-	334,174
283	Laboratory Equipment	395	-	-	402,713
284	Power Operated Equipment	396	-	-	951,880
285	Communications Equipment	397	-	-	22,459,793
286	Miscellaneous Equipment	398	-	-	145,242
287	Other Tangible Property	399	-	-	-
288			$ -	$ -	$ 82,740,289
289					
290	**Total Plant in Service - Gross**		**$ -**	**$ -**	**$ 2,085,155,457**
291					
292					
293					
294	**Accumulated Depreciation**				
301					
302	Steam Power Generation				
303	Land & Land Rights	310	$ -	$ -	$ -
304	Structures & Improvements	311	-	-	76,972,099
305	Boiler Plant Equipment	312	-	-	157,557,508
306	Engines and Engine Driven Generators	313	-	-	-
307	Turbogenerator Units	314	-	-	57,161,693
308	Accessory Plt Equipment	315	-	-	17,071,461
309	Miscellaneous Equipment	316	-	-	51,449,069
310			$ -	$ -	$ 360,211,830
311					
312	Nuclear Power Generation				
313	Land & Land Rights	320	$ -	$ -	$ -
314	Structures & Improvements	321	-	-	215,190,836
315	Reactor Plant Equipment	322	-	-	138,286,653
316	Turbogenerator Units	323	-	-	17,624,900
317	Accessory Plant Equipment	324	-	-	87,610,824
318	Miscellaneous Equipment	325	-	-	3,604,788
319			$ -	$ -	$ 462,318,000
320					
321	Combustion Turbine & Other Productior				
322	Land & Land Rights	340	$ -	$ -	$ -
323	Structures & Improvements	341	-	-	702,713
324	Fuel Holders, Producers and Accessories	342	-	-	1,671,650
325	Prime movers	343	-	-	236,787
326	Generator/PV	344	-	-	80,054,172
327	Accessory Elec Equip.	345	-	-	823,602
328	Miscellaneous Equipment	346	-	-	279,879
329			$ -	$ -	$ 83,768,802

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Direct Assignments Community Benefit Adj Clause	Direct Assignments Green Choice	Total
A		B	T	U	V
330					
331	**Total Power Generation Plant**		**$ -**	**$ -**	**$ 906,298,632**
332					
362					
363	**Subtotal Plant in Service Before General Plant**		**$ -**	**$ -**	**$ 906,298,632**
364					
365	General Plant				
366	Land & Land Rights	389	$ -	$ -	$ -
367	Structures & Improvements	390	-	-	14,782,554
368	Office Furniture & Equipment	391	-	-	6,718,817
369	Transportation Equipment	392	-	-	1,093,807
370	Stores Equipment	393	-	-	316,077
371	Tools, Shop & Garage Equipment	394	-	-	154,304
372	Laboratory Equipment	395	-	-	215,441
373	Power Operated Equipment	396	-	-	175,904
374	Communications Equipment	397	-	-	17,089,014
375	Miscellaneous Equipment	398	-	-	99,532
376	Other Tangible Property	399	-	-	-
377			$ -	$ -	$ 40,645,451
378					
379	**Total Plant in Service - Accumulated Depreciation**		**$ -**	**$ -**	**$ 946,944,083**
380					
381					
382					
383	**Net Plant In Service**				
390					
391	Steam Power Generation				
392	Land & Land Rights	310	$ -	$ -	$ 9,234,828
393	Structures & Improvements	311	-	-	12,476,645
394	Boiler Plant Equipment	312	-	-	254,278,143
395	Engines and Engine Driven Generators	313	-	-	-
396	Turbogenerator Units	314	-	-	18,496,121
397	Accessory Plt Equipment	315	-	-	13,643,601
398	Miscellaneous Equipment	316	-	-	11,314,042
399			$ -	$ -	$ 319,443,380
400					
401	Nuclear Power Generation				
402	Land & Land Rights	320	$ -	$ -	$ 2,782,002
403	Structures & Improvements	321	-	-	191,529,059
404	Reactor Plant Equipment	322	-	-	155,223,155
405	Turbogenerator Units	323	-	-	30,766,875
406	Accessory Plant Equipment	324	-	-	78,985,326
407	Miscellaneous Equipment	325	-	-	5,049,475
408			$ -	$ -	$ 464,335,891
409					
410	Combustion Turbine & Other Productior				
411	Land & Land Rights	340	$ -	$ -	$ 32,120
412	Structures & Improvements	341	-	-	6,035,344
413	Fuel Holders, Producers and Accessories	342	-	-	8,701,949
414	Prime movers	343	-	-	953,520
415	Generator/PV	344	-	-	292,441,196
416	Accessory Elec Equip.	345	-	-	2,338,570
417	Miscellaneous Equipment	346	-	-	1,834,565
418			$ -	$ -	$ 312,337,264
419					
420	**Total Power Generation Plant**		**$ -**	**$ -**	**$ 1,096,116,536**

Test Year Revenue Requirement - Production
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Direct Assignments: Community Benefit Adj Clause	Direct Assignments: Green Choice	Total
A		B	T	U	V
421					
451					
452	**Subtotal Plant in Service Before General Plant**		**$ -**	**$ -**	**$ 1,096,116,536**
453					
454	General Plant				
455	Land & Land Rights	389	$ -	$ -	$ 10,776,642
456	Structures & Improvements	390	-	-	13,720,101
457	Office Furniture & Equipment	391	-	-	10,277,603
458	Transportation Equipment	392	-	-	755,812
459	Stores Equipment	393	-	-	5,074
460	Tools, Shop & Garage Equipment	394	-	-	179,869
461	Laboratory Equipment	395	-	-	187,272
462	Power Operated Equipment	396	-	-	775,976
463	Communications Equipment	397	-	-	5,370,779
464	Miscellaneous Equipment	398	-	-	45,710
465	Other Tangible Property	399	-	-	-
466			$ -	$ -	$ 42,094,838
467					
468	**Total Plant in Service - Net**		**$ -**	**$ -**	**$ 1,138,211,374**
469					
470					
471					
472	**Depreciation Expense**				
479					
480	Steam Power Generation				
481	Land & Land Rights	310	$ -	$ -	$ -
482	Structures & Improvements	311	-	-	2,444,311
483	Boiler Plant Equipment	312	-	-	12,389,477
484	Engines and Engine Driven Generators	313	-	-	-
485	Turbogenerator Units	314	-	-	2,042,250
486	Accessory Plt Equipment	315	-	-	830,619
487	Miscellaneous Equipment	316	-	-	1,701,091
488			$ -	$ -	$ 19,407,749
489					
490	Nuclear Power Generation				
491	Land & Land Rights	320	$ -	$ -	$ -
492	Structures & Improvements	321	-	-	9,634,365
493	Reactor Plant Equipment	322	-	-	6,952,649
494	Turbogenerator Units	323	-	-	4,126,237
495	Accessory Plant Equipment	324	-	-	3,946,323
496	Miscellaneous Equipment	325	-	-	205,002
497			$ -	$ -	$ 24,864,576
498					
499	Combustion Turbine & Other Productior				
500	Land & Land Rights	340	$ -	$ -	$ -
501	Structures & Improvements	341	-	-	219,925
502	Fuel Holders, Producers and Accessories	342	-	-	337,791
503	Prime movers	343	-	-	38,618
504	Generator/PV	344	-	-	12,149,942
505	Accessory Elec Equip.	345	-	-	103,035
506	Miscellaneous Equipment	346	-	-	71,884
507			$ -	$ -	$ 12,921,195
508					
509	**Total Power Generation Plant**		**$ -**	**$ -**	**$ 57,193,519**
510					
540					

Test Year Revenue Requirement - Production
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Direct Assignments Community Benefit Adj Clause	Green Choice	Total
A		B	T	U	V
541	**Subtotal Plant in Service Before General Plant**		**$ -**	**$ -**	**$ 57,193,519**
542					
543	General Plant				
544	Land & Land Rights	389	$ -	$ -	$ -
545	Structures & Improvements	390	-	-	780,932
546	Office Furniture & Equipment	391	-	-	1,396,364
547	Transportation Equipment	392	-	-	137,729
548	Stores Equipment	393	-	-	358
549	Tools, Shop & Garage Equipment	394	-	-	22,197
550	Laboratory Equipment	395	-	-	31,277
551	Power Operated Equipment	396	-	-	18,627
552	Communications Equipment	397	-	-	1,402,687
553	Miscellaneous Equipment	398	-	-	7,545
554	Other Tangible Property	399	-	-	-
555			$ -	$ -	$ 3,797,717
556					
557	**Total Plant Depreciation**		**$ -**	**$ -**	**$ 60,991,236**
558					
559					
560					
561					
562					
563	**Labor**				
564					
565	**Power Production Expenses**				
566	Steam Power Generation				
567	**Operation**				
568	Operation Supervision and Engineering	500	$ -	$ -	$ 5,944,916
569	Fuel	501	-	-	662,876
570	Steam Expenses	502	-	-	2,694,376
571	Steam from other Sources	503	-	-	-
572	Steam Transferred	504	-	-	-
573	Electric Expenses	505	-	-	9,218
574	Miscellaneous Steam Expenses	506	-	-	369,140
575	Rents	507	-	-	-
576			$ -	$ -	$ 9,680,526
577					
578	**Maintenance**				
579	Maintenance Supervision	510	$ -	$ -	$ 2,196,111
580	Maintenance of Structures	511	-	-	8,944
581	Maintenance of Boiler Plant	512	-	-	181,843
582	Maintenance of Electric Plant	513	-	-	64,808
583	Maintenance of Miscellaneous Steam Plant	514	-	-	972,462
584	Rents	515	-	-	-
585			$ -	$ -	$ 3,424,167
586					
587	Nuclear Power Generation				
588	**Operation**				
589	Operation Supervision	517	$ -	$ -	$ 275,541
590	Nuclear Fuel Expense	518	-	-	-
591	Coolants and Water	519	-	-	-
592	Steam Expenses	520	-	-	-
593	Electric Expenses	523	-	-	-
594	Misc Nuclear Power Expenses	524	-	-	-
595	Rents	525	-	-	-
596			$ -	$ -	$ 275,541

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.		FERC Account	Direct Assignments: Community Benefit Adj Clause	Direct Assignments: Green Choice	Total
A		B	T	U	V
597					
598	**Maintenance**				
599	Maintenance Supervision	528	$ -	$ -	$ -
600	Maintenance of Structures	529	-	-	-
601	Maintenance of Reactor Plant	530	-	-	-
602	Maintenance of Electric Plant	531	-	-	-
603	Maintenance of Miscellaneous	532	-	-	-
604			$ -	$ -	$ -
605					
606	Hydraulic Power Generation				
607	**Maintenance**				
608	Maintenance Supervision	541	$ -	$ -	$ -
609	Maintenance of Structures	542	-	-	-
610	Maintenance of Reservoirs, Dams & Waterways	543	-	-	-
611	Maintenance of Electric Plant	544	-	-	-
612	Maintenance of Miscellaneous Hydraulic Plant	545	-	-	-
613			$ -	$ -	$ -
614					
615	Other Power Generation				
616	**Operation**				
617	Operation Supervision	546	$ -	$ -	$ 1,590,051
618	Fuel	547	-	-	-
619	Generation Expenses	548	-	-	2,001,778
620	Miscellaneous Other Power Generation Expenses	549	-	-	89,637
621	Rents	550	-	-	15
622			$ -	$ -	$ 3,681,481
623					
624	**Maintenance**				
625	Maintenance Supervision and Engineering	551	$ -	$ -	$ 43,116
626	Maintenance of Structures	552	-	-	50,665
627	Maintenance of Generating and Electric Equipment	553	-	-	1,287,085
628	Maintenance of Misc Other Power Generation Plant	554	-	-	795,529
629			$ -	$ -	$ 2,176,394
630					
631	Other Power Supply				
632	Purchased Power	555	$ -	$ -	$ -
633	System Control and Load Dispatching	556	-	-	1,657,074
634	Other Power Expenses	557	-	-	446,051
635			$ -	$ -	$ 2,103,125
636					
637	**Total Power Production Expense**		**$ -**	**$ -**	**$ 21,341,235**
638					
659					
660	**Total Transmission Expenses**		**$ -**	**$ -**	**$ -**
661					
687					
688	**Total Distribution Expenses**		**$ -**	**$ -**	**$ -**
689					
710					
711	**Total Customer and Information Expenses**		**$ -**	**$ -**	**$ -**
712					
713	**General and Administrative Expenses**				
714	Administrative and General Salaries	920	$ -	$ -	$ 10,189,883
715	Office Supplies and Expenses	921	-	-	2,840
716	Administrative Expense Transferred	922	-	-	-
717	Outside Services Employed	923	-	-	2,300

Test Year Revenue Requirement - Production
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.			FERC Account	Direct Assignments Community Benefit Adj Clause	Direct Assignments Green Choice	Total
A			B	T	U	V
718		Property Insurance	924	-	-	-
719		Injuries and Damages	925	-	-	-
720		Employee Pension and Benefits	926	-	-	-
721		Regulatory Commission Expense	928	-	-	-
722		General Expenses	930	-	-	240,083
723		Rents	931	-	-	-
724		Maintenance of General Plant	935	-	-	-
725				$ -	$ -	$ 10,435,106
726						
727	**Total Electric Labor**			**$ -**	**$ -**	**$ 31,776,341**
728						
729						
730						
731	**Allocation Factors**					
732	1	Regulatory		0.0%	0.0%	100.0%
733		Direct Assignment to Regulatory Clause				1
734						
735	2	Community Benefit		100.0%	0.0%	100.0%
736		Direct Assignment to Community Benefit Clause		1		1
737						
738	3	FERC 513	WP 24 - Pro	0.0%	0.0%	100.0%
739		Steam Generation FERC 513				1
740						
741	4	FERC 514	WP 24 - Pro	0.0%	0.0%	100.0%
742		Steam Generation FERC 514				1
743						
744	5	556 Non-Recoverable	WP 44 - PCF	0.0%	0.0%	100.0%
745		Direct Assignment to Green Choice and Remainder to Demand Relat		$ -	$ -	1,802,970
746		Other FERC 556 Non-Recoverable to Production Demand Related Re		$ -	$ -	$ 1,802,970
747		FERC 556 Non-Recoverable Direct to Green Choice		$ -	$ -	$ -
748						
749	6	555 Non-Recoverable	WP 44 - PCF	0.0%	96.7%	100.0%
750		Direct Assignments to GC and Remainder to Demand Related Wind (		$ -	$ 10,057,082	10,403,215
751		Direct Assignment to Green Choice		$ -	$ 10,057,082	$ 10,057,082
752		Other Non-Recoverable FERC 555 Allocated to Energy Related Winc		$ -	$ -	$ 346,133
753						
754	7	Prod RR - Demand		0.0%	0.0%	100.0%
755		Revenue Requirement Associated with Demand Related Generation				331,562,101
756						
757	8	Steam Fuel	WP 44 - PCF	0.0%	0.0%	100.0%
758		Steam Generation Fuel for Base Load and Intermediate				131,529,489
759						
760	9	Nuclear DA		0.0%	0.0%	100.0%
761		Direct Assignment to Demand Related Nuclear Generation				1
762						
763	10	Nuclear Fuel	WP 44 - PCF	0.0%	0.0%	100.0%
764		Nuclear Generation Fuel for Base Load Resource Type				19,347,060
765						
766	11	T Prod Plant - Depr		0.0%	0.0%	100.0%
767		Total Depreciation for Production Plant In Service, Including General		-	-	60,991,236
768						
769	12	Other Fuel	WP 44 - PCF	0.0%	0.0%	100.0%
770		Other Generation Fuel for Intermediate and Peak				122,429,167
771						
772	13	FERC 500	WP 24 - Pro	0.0%	0.0%	100.0%
773		Steam Generation FERC 500				1
774						

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.			FERC Account	Direct Assignments Community Benefit Adj Clause	Green Choice	Total
A			B	T	U	V
775	14	FERC 502	WP 24 - Pro	0.0%	0.0%	100.0%
776		Steam Generation FERC 502				1
777						
778	15	FERC 505	WP 24 - Pro	0.0%	0.0%	100.0%
779		Steam Generation FERC 505				1
780						
781	16	FERC 506	WP 24 - Pro	0.0%	0.0%	100.0%
782		Steam Generation FERC 506				1
783						
784	17	FERC 510	WP 24 - Pro	0.0%	0.0%	100.0%
785		Steam Generation FERC 510				1
786						
787	18	FERC 511	WP 24 - Pro	0.0%	0.0%	100.0%
788		Steam Generation FERC 511				1
789						
790	19	FERC 512	WP 24 - Pro	0.0%	0.0%	100.0%
791		Steam Generation FERC 512				1
792						
793	20	Prod RR		0.0%	0.0%	100.0%
794		Generation Revenue Requirement, Excluding DA to Regulatory and C				754,113,820
795						
796	21	Prod 920	WP 6 - G&A	0.0%	0.0%	100.0%
797		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Ex		$ -	$ -	$ 8,849,743
798		FERC 920 STP Direct to Production		$ -	$ -	$ 1,913,089
799		FERC 920 FPP Direct to Production		$ -	$ -	$ -
800		Other Allocated FERC 920 to Production		$ -	$ -	$ 6,936,655
801						
802	22	Prod 921	WP 6 - G&A	0.0%	0.0%	100.0%
803		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Ex		$ -	$ -	5,273,986
804		FERC 921 STP Direct to Production		$ -	$ -	$ 483,491
805		FERC 921 FPP Direct to Production		$ -	$ -	$ -
806		Other Allocated FERC 921 to Production		$ -	$ -	$ 4,790,494
807						
808	23	Prod Labor		0.0%	0.0%	100.0%
809		Total Production Labor, Excluding G&A and DA to Regulatory and Co				21,341,235
810						
811	24	Prod 923	WP 6 - G&A	0.0%	0.0%	100.0%
812		Based on Direct Allocations in WP 6 - G&A and Total Production O&M		$ -	$ -	$ 5,754,009
813		FERC 923 STP Direct to Production		$ -	$ -	$ 1,513,819
814		FERC 923 FPP Direct to Production		$ -	$ -	$ -
815		Other Allocated FERC 923 to Production		$ -	$ -	$ 4,240,190
816						
817	25	Prod 924	WP 6 - G&A	0.0%	0.0%	100.0%
818		Based on Direct Allocations in WP 6 - G&A and Generation Net Plant		$ -	$ -	2,258,015
819		FERC 924 STP Direct to Production		$ -	$ -	$ 425,511
820		FERC 924 FPP and Boiler Insurance Direct to Productior		$ -	$ -	$ 275,473
821		Other Allocated FERC 924 to Production		$ -	$ -	$ 1,557,031
822						
823	26	Prod 925	WP 6 - G&A	0.0%	0.0%	100.0%
824		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Ex		$ -	$ -	1,097,461
825		FERC 925 STP Direct to Production		$ -	$ -	$ 384,328
826		FERC 925 FPP Direct to Production		$ -	$ -	$ 125,803
827		Other Allocated FERC 925 to Production		$ -	$ -	$ 587,331
828						
829	27	Prod 926	WP 6 - G&A	0.0%	0.0%	100.0%
830		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Ex		$ -	$ -	9,931,952
831		FERC 926 STP Direct to Production		$ -	$ -	$ 6,541,200

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.			FERC Account	Direct Assignments Community Benefit Adj Clause	Green Choice	Total
A			B	T	U	V
832		FERC 926 FPP Direct to Production		$ -	$ -	$ 3,249,249
833		Other Allocated FERC 926 to Productior		$ -	$ -	$ 141,503
834						
835	28	Prod 930	WP 6 - G&A	0.0%	0.0%	100.0%
836		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Ex		$ -	$ -	6,524,359
837		FERC 930 STP Direct to Production		$ -	$ -	$ 749,995
838		FERC 930 FPP Direct to Production		$ -	$ -	$ 1,070,546
839		Other Allocated FERC 930 to Productior		$ -	$ -	$ 4,703,818
840						
841	29	Prod 935	WP 6 - G&A	0.0%	0.0%	100.0%
842		Based on Direct Allocations in WP 6 - G&A and Generation Net Plant		$ -	$ -	895,159
843		FERC 935 STP Direct to Production		$ -	$ -	$ 874,593
844		FERC 935 FPP Direct to Production		$ -	$ -	$ -
845		Other Allocated FERC 935 to Productior		$ -	$ -	$ 20,566
846						
847	30	555 Recoverable	WP 44 - PCF	0.0%	0.0%	100.0%
848		Direct Assignments of FERC 555 Recoverable		$ -	$ -	96,511,902
849		FERC 555 Recoverable Direct to Economy Purchase Powe		$ -	$ -	$ 23,084,089
850		FERC 555 Recoverable Direct to Wind		$ -	$ -	$ 58,628,188
851		FERC 555 Recoverable Direct to Landfill Methane		$ -	$ -	$ 3,322,545
852		FERC 555 Recoverable Direct to Solar		$ -	$ -	$ 11,477,080
853						
854	31	556 Recoverable	WP 28.1 - F	0.0%	0.0%	100.0%
855		Direct Assignments of FERC 556 Recoverable to Regulatory Clause		$ -	$ -	21,079,958
856		FERC 556 Recoverable Direct to Regulatory		$ -	$ -	$ 9,839,798
857		Allocation to Demand Related Revenue Requirement		$ -	$ -	$ -
858		Allocation to Energy Related Revenue Requirement		$ -	$ -	$ 11,240,159
859						
860	32	Prod Debt Service	WP 5.3 - De	0.0%	0.0%	100.0%
861		Sub-functionalization of Debt Service Based on Detailed Allocation o				88,022,271
862						
863	33	Steam Plant - G	WP 26 - Pro	0.0%	0.0%	100.0%
864						678,958,146
865						
866	34	Steam Plant - AD	WP 26 - Pro	0.0%	0.0%	100.0%
867						360,041,047
868						
869	35	Steam Plant - Depr	WP 26 - Pro	0.0%	0.0%	100.0%
870						19,387,811
871						
872	36	Steam Plant - Net	WP 26 - Pro	0.0%	0.0%	100.0%
873						318,917,099
874						
875	37	Other Gen Plant - G	WP 26 - Pro	0.0%	0.0%	100.0%
876						396,803,130
877						
878	38	Other Gen Plant - AD	WP 26 - Pro	0.0%	0.0%	100.0%
879						83,939,585
880						
881	39	Other Gen Plant - Depr	WP 26 - Pro	0.0%	0.0%	100.0%
882						12,941,132
883						
884	40	Other Gen Plant - Net	WP 26 - Pro	0.0%	0.0%	100.0%
885						312,863,545
886						
887	41	Prod RR - Energy		0.0%	0.0%	100.0%
888		Revenue Requirement Associated with Energy Related Generation				422,551,719

Test Year Revenue Requirement - Production

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.			FERC Account	Direct Assignments		Total
				Community Benefit Adj Clause	Green Choice	
A			B	T	U	V
889						
890	42	Prod Plant - Net	WP 26 - Pro	0.0%	0.0%	100.0%
891		Net Production Plant In Service (excluding General Plant)				1,096,116,536
892						
893	43	FERC 546	WP 24 - Pro	0.0%	0.0%	100.0%
894		Other Power Generation FERC 546				1
895						
896	44	FERC 548	WP 24 - Pro	0.0%	0.0%	100.0%
897		Other Power Generation FERC 548				1
898						
899	45	FERC 549	WP 24 - Pro	0.0%	0.0%	100.0%
900		Other Power Generation FERC 549				1
901						
902	46	FERC 550	WP 24 - Pro	0.0%	0.0%	100.0%
903		Other Power Generation FERC 550				1
904						
905	47	FERC 551	WP 24 - Pro	0.0%	0.0%	100.0%
906		Other Power Generation FERC 551				1
907						
908	48	FERC 552	WP 24 - Pro	0.0%	0.0%	100.0%
909		Other Power Generation FERC 552				1
910						
911	49	FERC 553	WP 24 - Pro	0.0%	0.0%	100.0%
912		Other Power Generation FERC 553				1
913						
914	50	FERC 554	WP 24 - Pro	0.0%	0.0%	100.0%
915		Other Power Generation FERC 554				1
916						
917	51	Prod 931	WP 6 - G&A	0.0%	0.0%	100.0%
918		Based on Direct Allocations in WP 6 - G&A and Generation Labor, Ex		$ -	$ -	562,234
919		FERC 931 STP Direct to Production		$ -	$ -	$ -
920		FERC 931 FPP Direct to Production		$ -	$ -	$ -
921		Other Allocated FERC 931 to Production		$ -	$ -	$ 562,234
922						
923	52	Prod O&M EXAGF		0.0%	0.0%	100.0%
924		Total Production O&M, Excluding G&A, Commodity Fuel and Purcha:				114,095,132
925						
926	53	Base Coal DA		0.0%	0.0%	100.0%
927		Direct Assignment to Demand Related Base Load Coal Generation				1
928						
929	54	Green Choice DA		0.0%	100.0%	100.0%
930		Direct Assignment to Green Choice			1	1
931						
932	55	501 Non-Recoverable	WP 44 - PCF	0.0%	0.0%	100.0%
933		Allocation of FERC 501 Non-Recoverable Based on Steam Fuel Expen		$ -	$ -	131,529,489
934				$ -	$ -	$ 109,552,730
935				$ -	$ -	$ 21,976,759
936						
937	56	Solar Energy DA		0.0%	0.0%	100.0%
938		Direct Assignment of Solar to Energy				1
939						
940	57	Wind Energy DA		0.0%	0.0%	100.0%
941		Direct Assignment of Wind to Energy				1
942						
943	58	Econ PP DA		0.0%	0.0%	100.0%
944		Direct Assignment of Economy Purchase Power to Energy				1
945						

Test Year Revenue Requirement - Production
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Productior

Line No.			FERC Account	Direct Assignments Community Benefit Adj Clause	Green Choice	Total	
A			B	T	U	V	
946	61	Int Gas DA		0.0%	0.0%	100.0%	
947		Direct Assignment to Intermediate Gas					1
948							
949	62	Peak Gas DA		0.0%	0.0%	100.0%	
950		Direct Assignment to Peak Gas					1
951							
952	63	LF Gas Energy DA		0.0%	0.0%	100.0%	
953		Direct Assignment of Landfill Methane to Energy					1

Test Year Revenue Requirement - Transmission

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Transmission

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Transmission Infrastructure	Demand Related: Load Dispatch	Demand Related: Transmission By Others	Total
A		B	C	D	E	F	G	H	I
78									
79	**Total Power Production Expense**			$ -		$ -	$ -	$ -	$ -
80									
81	**Transmission Expense**								
82	**Operation**								
83	Operations Supervision and Engineering	560	Functional Unbundling	$ 5,133,166	Trans Infrastructure DA	$ 5,133,166	$ -	$ -	$ 5,133,166
84	Load Dispatching	561	Functional Unbundling	1,632,624	T Load Dispatch	-	1,632,624	-	1,632,624
85	Station Expenses	562	Functional Unbundling	385,383	Trans Infrastructure DA	385,383	-	-	385,383
86	Overhead Line Expenses	563	Functional Unbundling	1,159,438	Trans Infrastructure DA	1,159,438	-	-	1,159,438
87	Underground Line Expenses	564	Functional Unbundling	-	Trans Infrastructure DA	-	-	-	-
88	Transmission of Electricity by Others	565	Functional Unbundling	65,915,251	Trans by Others	-	-	65,915,251	65,915,251
89	Miscellaneous Transmission Expenses	566	Functional Unbundling	606,178	Trans Infrastructure DA	606,178	-	-	606,178
90	Rents	567	Functional Unbundling	3,000	Trans Infrastructure DA	3,000	-	-	3,000
91				$ 74,835,040		$ 7,287,164	$ 1,632,624	$ 65,915,251	$ 74,835,040
92									
93	**Maintenance**								
94	Maintenance Supervision and Engineering	568	Functional Unbundling	$ 344,737	Trans Infrastructure DA	$ 344,737	$ -	$ -	$ 344,737
95	Maintenance of Structures	569	Functional Unbundling	30,235	Trans Infrastructure DA	30,235	-	-	30,235
96	Maintenance of Station Equipment	570	Functional Unbundling	1,253,176	Trans Infrastructure DA	1,253,176	-	-	1,253,176
97	Maintenance of Overhead Lines	571	Functional Unbundling	1,305,322	Trans Infrastructure DA	1,305,322	-	-	1,305,322
98	Maintenance of Underground Lines	572	Functional Unbundling	36,353	Trans Infrastructure DA	36,353	-	-	36,353
99	Maintenance of Miscellaneous Transmission Plant	573	Functional Unbundling	14,460	Trans Infrastructure DA	14,460	-	-	14,460
100				$ 2,984,283		$ 2,984,283	$ -	$ -	$ 2,984,283
101									
102	**Total Transmission Expenses**			**$ 77,819,322**		**$ 10,271,447**	**$ 1,632,624**	**$ 65,915,251**	**$ 77,819,322**
103									
129									
130	**Total Distribution Expenses**			$ -		$ -	$ -	$ -	$ -
131									
152									
153	**Total Customer and Information Expenses**			$ -		$ -	$ -	$ -	$ -
154									
155	**General and Administrative Expenses**								
156	Administrative and General Salaries	920	Functional Unbundling	$ 2,761,525	Trans Labor	$ 2,247,064	$ 514,461	$ -	$ 2,761,525
157	Office Supplies and Expenses	921	Functional Unbundling	1,907,125	Trans Labor	1,551,835	355,290	-	1,907,125
158	Administrative Expense Transferred	922	Functional Unbundling	119,435	Trans Labor	97,184	22,250	-	119,435
159	Outside Services Employed	923	Functional Unbundling	1,904,049	Trans O&M EXAG	1,642,912	261,137	-	1,904,049
160	Property Insurance	924	Functional Unbundling	95,671	Trans Plant - Net	95,671	-	-	95,671
161	Injuries and Damages	925	Functional Unbundling	233,820	Trans Labor	190,260	43,560	-	233,820
162	Employee Pension and Benefits	926	Functional Unbundling	56,333	Trans Labor	45,839	10,495	-	56,333
163	Regulatory Commission Expense	928	Functional Unbundling	158,459	Trans RR	149,597	8,862	-	158,459
164	General Expenses	930	Functional Unbundling	1,872,619	Trans Labor	1,523,757	348,861	-	1,872,619
165	Rents	931	Functional Unbundling	-	Trans Labor	-	-	-	-
166	Maintenance of General Plant	935	Functional Unbundling	8,006	Trans General Plnt - Net	6,514	1,491	-	8,006
167				$ 9,117,040		$ 7,550,633	$ 1,566,406	$ -	$ 9,117,040
168									
169	**Total Operations & Maintenance Expenses**			**$ 86,936,362**		**$ 17,822,081**	**$ 3,199,030**	**$ 65,915,251**	**$ 86,936,362**
170									
171	**Depreciation & Amortization of CIAC**								
172	Depreciation Expense	403	Functional Unbundling	$ 13,096,126	T Trans Plant - Depr	$ 12,733,716	$ 362,411	$ -	$ 13,096,126
173	Amortization of CIAC		Functional Unbundling	(22,415)	T Trans Plant - Depr	(21,795)	(620)	-	(22,415)
174				**$ 13,073,711**		**$ 12,711,921**	**$ 361,790**	**$ -**	**$ 13,073,711**
175									
176	**Debt Service**		Functional Unbundling	**$ 30,414,912**	Trans Plant - Net	**$ 30,414,912**	**$ -**	**$ -**	**$ 30,414,912**
177									
178	**General Fund Transfer**	421.5	Functional Unbundling	**$ 5,982,279**	Trans RR	**$ 5,647,714**	**$ 334,566**	**$ -**	**$ 5,982,279**

Test Year Revenue Requirement - Transmission

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Transmission

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Transmission Infrastructure	Demand Related: Load Dispatch	Demand Related: Transmission By Others	Total
A		B	C	D	E	F	G	H	I
179									
180	**Margin**		Functional Unbundling	$ (1,662,032)	T Trans Plant - Depr	$ (1,616,039)	$ (45,994)	$ -	$ (1,662,032)
181									
182	**Sub-Total Revenue Requirement**			**$ 134,745,232**		**$ 64,980,588**	**$ 3,849,393**	**$ 65,915,251**	**$ 134,745,232**
183									
184	**Other Expenses**								
185	Misc Service Revenue	451	Functional Unbundling	$ -	Trans RR	$ -	$ -	$ -	$ -
186	Donations	426	Functional Unbundling	-	Trans RR	-	-	-	-
187	Taxes Other Than Income	408	Functional Unbundling	1,540	Trans RR	1,454	86	-	1,540
188	Expenses - Non-utility operations	417	Functional Unbundling	-	Trans RR	-	-	-	-
189	Franchise Fees		Functional Unbundling	-	Trans RR	-	-	-	-
190				**$ 1,540**		**$ 1,454**	**$ 86**	**$ -**	**$ 1,540**
191									
192	**Other (Non-Rate) Revenue**								
193	Miscellaneous Nonoperating Income	421	Functional Unbundling	$ 635	Trans RR	$ 599	$ 35	$ -	$ 635
194	Other Revenue		Functional Unbundling	68,830,887	Trans RR	64,981,444	3,849,443	-	68,830,887
195	Off-System Sales		Functional Unbundling	-	Trans RR	-	-	-	-
196				**$ 68,831,521**		**$ 64,982,043**	**$ 3,849,479**	**$ -**	**$ 68,831,521**
197									
198	**Total Revenue Requirement**			**$ 65,915,251**		**$ 0**	**$ 0**	**$ 65,915,251**	**$ 65,915,251**
199									
200	**System Retail Sales (MWH)**		Functional Unbundling	11,813,939					
201	Average Rate ($/MWh)			$ 5.58					
202									
203									
204									
205	**Gross Plant In Service**								
244	Transmission Plant								
245	Land & Land Rights	350	WP 2	$ 20,740,100	Trans Infrastructure DA	$ 20,740,100	$ -	$ -	$ 20,740,100
246	Clearing Land	351	WP 2	-	Trans Infrastructure DA	-	-	-	-
247	Structures & Improvements	352	WP 2	23,404,638	Trans Infrastructure DA	23,404,638	-	-	23,404,638
248	Station Equipment	353	WP 2	158,733,486	Trans Infrastructure DA	158,733,486	-	-	158,733,486
249	Towers and Fixtures	354	WP 2	43,594,735	Trans Infrastructure DA	43,594,735	-	-	43,594,735
250	Poles and Fixtures	355	WP 2	60,307,696	Trans Infrastructure DA	60,307,696	-	-	60,307,696
251	Overhead Conductors and Devices	356	WP 2	83,557,094	Trans Infrastructure DA	83,557,094	-	-	83,557,094
252	Underground Conduit	357	WP 2	4,945,414	Trans Infrastructure DA	4,945,414	-	-	4,945,414
253	Underground Conductors and Devices	358	WP 2	8,076,095	Trans Infrastructure DA	8,076,095	-	-	8,076,095
254	Roads and Trails	359	WP 2	854,121	Trans Infrastructure DA	854,121	-	-	854,121
255				$ 404,213,378		$ 404,213,378	$ -	$ -	$ 404,213,378
256									
273									
274	**Subtotal Plant in Service Before General Plant**			**$ 404,213,378**		**$ 404,213,378**	**$ -**	**$ -**	**$ 404,213,378**
275									
276	General Plant								
277	Land & Land Rights	389	WP 2	$ 2,639,537	Trans Labor	$ 2,147,802	$ 491,735	$ -	$ 2,639,537
278	Structures & Improvements	390	WP 2	6,981,191	Trans Labor	5,680,624	1,300,567	-	6,981,191
279	Office Furniture & Equipment	391	WP 2	7,666,547	Trans Labor	6,238,301	1,428,246	-	7,666,547
280	Transportation Equipment	392	WP 2	9,154,894	Trans Labor	7,449,375	1,705,519	-	9,154,894
281	Stores Equipment	393	WP 2	75,935	Trans Labor	61,789	14,146	-	75,935
282	Tools, Shop & Garage Equipment	394	WP 2	448,403	Trans Labor	364,867	83,536	-	448,403
283	Laboratory Equipment	395	WP 2	95,220	Trans Labor	77,481	17,739	-	95,220
284	Power Operated Equipment	396	WP 2	225,069	Trans Labor	183,139	41,929	-	225,069
285	Communications Equipment	397	WP 2	6,389,755	Trans Labor	5,199,370	1,190,385	-	6,389,755
286	Miscellaneous Equipment	398	WP 2	34,342	Trans Labor	27,944	6,398	-	34,342
287	Other Tangible Property	399	WP 2	-	Trans Labor	-	-	-	-
288				$ 33,710,894		$ 27,430,693	$ 6,280,201	$ -	$ 33,710,894

Test Year Revenue Requirement - Transmission

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Transmission

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Transmission Infrastructure	Demand Related: Load Dispatch	Demand Related: Transmission By Others	Total
A		B	C	D	E	F	G	H	I
289									
290	**Total Plant in Service - Gross**			**$ 437,924,271**		**$ 431,644,070**	**$ 6,280,201**	**$ -**	**$ 437,924,271**
291									
292									
293									
294	**Accumulated Depreciation**								
333	Transmission Plant								
334	Land & Land Rights	350	WP 2	$ -	Trans Infrastructure DA	$ -	$ -	$ -	$ -
335	Clearing Land	351	WP 2	-	Trans Infrastructure DA	-	-	-	-
336	Structures & Improvements	352	WP 2	7,673,215	Trans Infrastructure DA	7,673,215	-	-	7,673,215
337	Station Equipment	353	WP 2	43,762,905	Trans Infrastructure DA	43,762,905	-	-	43,762,905
338	Towers and Fixtures	354	WP 2	29,260,913	Trans Infrastructure DA	29,260,913	-	-	29,260,913
339	Poles and Fixtures	355	WP 2	20,902,393	Trans Infrastructure DA	20,902,393	-	-	20,902,393
340	Overhead Conductors and Devices	356	WP 2	40,591,204	Trans Infrastructure DA	40,591,204	-	-	40,591,204
341	Underground Conduit	357	WP 2	1,104,755	Trans Infrastructure DA	1,104,755	-	-	1,104,755
342	Underground Conductors and Devices	358	WP 2	1,500,483	Trans Infrastructure DA	1,500,483	-	-	1,500,483
343	Roads and Trails	359	WP 2	244,426	Trans Infrastructure DA	244,426	-	-	244,426
344				$ 145,040,292		$ 145,040,292	$ -	$ -	$ 145,040,292
345									
362									
363	**Subtotal Plant in Service Before General Plant**			**$ 145,040,292**		**$ 145,040,292**	**$ -**	**$ -**	**$ 145,040,292**
364									
365	General Plant								
366	Land & Land Rights	389	WP 2	$ -	Trans Labor	$ -	$ -	$ -	$ -
367	Structures & Improvements	390	WP 2	3,620,710	Trans Labor	2,946,186	674,523	-	3,620,710
368	Office Furniture & Equipment	391	WP 2	3,030,646	Trans Labor	2,466,049	564,597	-	3,030,646
369	Transportation Equipment	392	WP 2	5,413,918	Trans Labor	4,405,328	1,008,591	-	5,413,918
370	Stores Equipment	393	WP 2	74,735	Trans Labor	60,812	13,923	-	74,735
371	Tools, Shop & Garage Equipment	394	WP 2	207,050	Trans Labor	168,477	38,572	-	207,050
372	Laboratory Equipment	395	WP 2	50,940	Trans Labor	41,450	9,490	-	50,940
373	Power Operated Equipment	396	WP 2	41,592	Trans Labor	33,844	7,748	-	41,592
374	Communications Equipment	397	WP 2	4,861,782	Trans Labor	3,956,052	905,730	-	4,861,782
375	Miscellaneous Equipment	398	WP 2	23,534	Trans Labor	19,150	4,384	-	23,534
376	Other Tangible Property	399	WP 2	-	Trans Labor	-	-	-	-
377				$ 17,324,907		$ 14,097,348	$ 3,227,559	$ -	$ 17,324,907
378									
379	**Total Plant in Service - Accumulated Depreciation**			**$ 162,365,199**		**$ 159,137,640**	**$ 3,227,559**	**$ -**	**$ 162,365,199**
380									
381									
382									
383	**Net Plant In Service**								
422	Transmission Plant								
423	Land & Land Rights	350	WP 2	$ 20,740,100	Trans Infrastructure DA	$ 20,740,100	$ -	$ -	$ 20,740,100
424	Clearing Land	351	WP 2	-	Trans Infrastructure DA	-	-	-	-
425	Structures & Improvements	352	WP 2	15,731,423	Trans Infrastructure DA	15,731,423	-	-	15,731,423
426	Station Equipment	353	WP 2	114,970,581	Trans Infrastructure DA	114,970,581	-	-	114,970,581
427	Towers and Fixtures	354	WP 2	14,333,822	Trans Infrastructure DA	14,333,822	-	-	14,333,822
428	Poles and Fixtures	355	WP 2	39,405,304	Trans Infrastructure DA	39,405,304	-	-	39,405,304
429	Overhead Conductors and Devices	356	WP 2	42,965,890	Trans Infrastructure DA	42,965,890	-	-	42,965,890
430	Underground Conduit	357	WP 2	3,840,659	Trans Infrastructure DA	3,840,659	-	-	3,840,659
431	Underground Conductors and Devices	358	WP 2	6,575,612	Trans Infrastructure DA	6,575,612	-	-	6,575,612
432	Roads and Trails	359	WP 2	609,695	Trans Infrastructure DA	609,695	-	-	609,695
433				$ 259,173,086		$ 259,173,086	$ -	$ -	$ 259,173,086
434									
451									
452	**Subtotal Plant in Service Before General Plant**			**$ 259,173,086**		**$ 259,173,086**	**$ -**	**$ -**	**$ 259,173,086**

Test Year Revenue Requirement - Transmission

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Transmission

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Transmission Infrastructure	Demand Related: Load Dispatch	Demand Related: Transmission By Others	Total
A		B	C	D	E	F	G	H	I
453									
454	General Plant								
455	Land & Land Rights	389	WP 2	$ 2,639,537	Trans Labor	$ 2,147,802	$ 491,735	$ -	$ 2,639,537
456	Structures & Improvements	390	WP 2	3,360,482	Trans Labor	2,734,438	626,044	-	3,360,482
457	Office Furniture & Equipment	391	WP 2	4,635,901	Trans Labor	3,772,252	863,649	-	4,635,901
458	Transportation Equipment	392	WP 2	3,740,976	Trans Labor	3,044,047	696,928	-	3,740,976
459	Stores Equipment	393	WP 2	1,200	Trans Labor	976	224	-	1,200
460	Tools, Shop & Garage Equipment	394	WP 2	241,354	Trans Labor	196,390	44,963	-	241,354
461	Laboratory Equipment	395	WP 2	44,280	Trans Labor	36,031	8,249	-	44,280
462	Power Operated Equipment	396	WP 2	183,477	Trans Labor	149,296	34,181	-	183,477
463	Communications Equipment	397	WP 2	1,527,973	Trans Labor	1,243,318	284,655	-	1,527,973
464	Miscellaneous Equipment	398	WP 2	10,808	Trans Labor	8,795	2,014	-	10,808
465	Other Tangible Property	399	WP 2	-	Trans Labor	-	-	-	-
466				$ 16,385,987		$ 13,333,345	$ 3,052,642	$ -	$ 16,385,987
467									
468	**Total Plant in Service - Net**			**$ 275,559,073**		**$ 272,506,430**	**$ 3,052,642**	**$ -**	**$ 275,559,073**
469									
470									
471									
472	**Depreciation Expense**								
511	Transmission Plant								
512	Land & Land Rights	350	WP 2	$ -	Trans Infrastructure DA	$ -	$ -	$ -	$ -
513	Clearing Land	351	WP 2	-	Trans Infrastructure DA	-	-	-	-
514	Structures & Improvements	352	WP 2	793,273	Trans Infrastructure DA	793,273	-	-	793,273
515	Station Equipment	353	WP 2	3,924,737	Trans Infrastructure DA	3,924,737	-	-	3,924,737
516	Towers and Fixtures	354	WP 2	1,354,543	Trans Infrastructure DA	1,354,543	-	-	1,354,543
517	Poles and Fixtures	355	WP 2	1,955,012	Trans Infrastructure DA	1,955,012	-	-	1,955,012
518	Overhead Conductors and Devices	356	WP 2	2,682,983	Trans Infrastructure DA	2,682,983	-	-	2,682,983
519	Underground Conduit	357	WP 2	161,069	Trans Infrastructure DA	161,069	-	-	161,069
520	Underground Conductors and Devices	358	WP 2	256,552	Trans Infrastructure DA	256,552	-	-	256,552
521	Roads and Trails	359	WP 2	22,607	Trans Infrastructure DA	22,607	-	-	22,607
522				$ 11,150,776		$ 11,150,776	$ -	$ -	$ 11,150,776
523									
540									
541	**Subtotal Plant in Service Before General Plant**			**$ 11,150,776**		**$ 11,150,776**	**$ -**	**$ -**	**$ 11,150,776**
542									
543	General Plant								
544	Land & Land Rights	389	WP 2	$ -	Trans Labor	$ -	$ -	$ -	$ -
545	Structures & Improvements	390	WP 2	191,275	Trans Labor	155,641	35,634	-	191,275
546	Office Furniture & Equipment	391	WP 2	629,856	Trans Labor	512,516	117,340	-	629,856
547	Transportation Equipment	392	WP 2	681,705	Trans Labor	554,706	126,999	-	681,705
548	Stores Equipment	393	WP 2	85	Trans Labor	69	16	-	85
549	Tools, Shop & Garage Equipment	394	WP 2	29,785	Trans Labor	24,236	5,549	-	29,785
550	Laboratory Equipment	395	WP 2	7,395	Trans Labor	6,018	1,378	-	7,395
551	Power Operated Equipment	396	WP 2	4,404	Trans Labor	3,584	820	-	4,404
552	Communications Equipment	397	WP 2	399,061	Trans Labor	324,718	74,343	-	399,061
553	Miscellaneous Equipment	398	WP 2	1,784	Trans Labor	1,452	332	-	1,784
554	Other Tangible Property	399	WP 2	-	Trans Labor	-	-	-	-
555				$ 1,945,350		$ 1,582,939	$ 362,411	$ -	$ 1,945,350
556									
557	**Total Plant Depreciation**			**$ 13,096,126**		**$ 12,733,716**	**$ 362,411**	**$ -**	**$ 13,096,126**
558									
559									
560									
561									
562									

Test Year Revenue Requirement - Transmission

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Transmission

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Transmission Infrastructure	Demand Related: Load Dispatch	Demand Related: Transmission By Others	Total
A		B	C	D	E	F	G	H	I
563	**Labor**								
564									
636									
637	**Total Power Production Expense**			$ -		$ -	$ -	$ -	$ -
638									
639	**Transmission Expense**								
640	**Operation**								
641	Operations Supervision and Engineering	560	WP 3.1	$ 5,111,339	Trans Infrastructure DA	$ 5,111,339	$ -	$ -	$ 5,111,339
642	Load Dispatching	561	WP 3.1	1,582,680	T Load Dispatch	-	1,582,680	-	1,582,680
643	Station Expenses	562	WP 3.1	83,598	Trans Infrastructure DA	83,598	-	-	83,598
644	Overhead Line Expenses	563	WP 3.1	548,764	Trans Infrastructure DA	548,764	-	-	548,764
645	Underground Line Expenses	564	WP 3.1	-	Trans Infrastructure DA	-	-	-	-
646	Transmission of Electricity by Others	565	WP 3.1	105	T Load Dispatch	-	105	-	105
647	Miscellaneous Transmission Expenses	566	WP 3.1	109,413	Trans Infrastructure DA	109,413	-	-	109,413
648	Rents	567	WP 3.1	-	Trans Infrastructure DA	-	-	-	-
649				$ 7,435,897		$ 5,853,113	$ 1,582,784	$ -	$ 7,435,897
650									
651	**Maintenance**								
652	Maintenance Supervision and Engineering	568	WP 3.1	$ 66	Trans Infrastructure DA	$ 66	$ -	$ -	$ 66
653	Maintenance of Structures	569	WP 3.1	1,982	Trans Infrastructure DA	1,982	-	-	1,982
654	Maintenance of Station Equipment	570	WP 3.1	875,347	Trans Infrastructure DA	875,347	-	-	875,347
655	Maintenance of Overhead Lines	571	WP 3.1	179,242	Trans Infrastructure DA	179,242	-	-	179,242
656	Maintenance of Underground Lines	572	WP 3.1	-	Trans Infrastructure DA	-	-	-	-
657	Maintenance of Miscellaneous Transmission Plant	573	WP 3.1	3,542	Trans Infrastructure DA	3,542	-	-	3,542
658				$ 1,060,179		$ 1,060,179	$ -	$ -	$ 1,060,179
659									
660	**Total Transmission Expenses**			**$ 8,496,076**		**$ 6,913,292**	**$ 1,582,784**	**$ -**	**$ 8,496,076**
661									
710									
711	**Total Customer and Information Expenses**			$ -		$ -	$ -	$ -	$ -
712									
713	**General and Administrative Expenses**								
714	Administrative and General Salaries	920	WP 3.1	$ 4,056,654	Trans Labor	$ 3,300,916	$ 755,738	$ -	$ 4,056,654
715	Office Supplies and Expenses	921	WP 3.1	1,131	Trans Labor	920	211	-	1,131
716	Administrative Expense Transferred	922	WP 3.1	-	Trans Labor	-	-	-	-
717	Outside Services Employed	923	WP 3.1	1,033	Trans O&M EXAG	891	142	-	1,033
718	Property Insurance	924	WP 3.1	-	Trans Plant - Net	-	-	-	-
719	Injuries and Damages	925	WP 3.1	-	Trans Labor	-	-	-	-
720	Employee Pension and Benefits	926	WP 3.1	-	Trans Labor	-	-	-	-
721	Regulatory Commission Expense	928	WP 3.1	-	Trans RR	-	-	-	-
722	General Expenses	930	WP 3.1	95,579	Trans Labor	77,773	17,806	-	95,579
723	Rents	931	WP 3.1	-	Trans Labor	-	-	-	-
724	Maintenance of General Plant	935	WP 3.1	-	Trans General Plnt - Net	-	-	-	-
725				$ 4,154,396		$ 3,380,500	$ 773,896	$ -	$ 4,154,396
726									
727	**Total Electric Labor**			**$ 12,650,472**		**$ 10,293,792**	**$ 2,356,680**	**$ -**	**$ 12,650,472**
728									
729									
730									
731	**Allocation Factors**								
732	1 Trans by Others					0.0%	0.0%	100.0%	100.0%
733	Direct Assignment to Transmission of Electricity by Others (FERC 565)							1	1
734									
735	2 T Load Dispatch					0.0%	100.0%	0.0%	100.0%
736	Direct Assignment to Load Dispatch within the Transmission Function						1		1
737									

Test Year Revenue Requirement - Transmission

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Transmission

Line No.			FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Transmission Infrastructure	Demand Related: Load Dispatch	Demand Related: Transmission By Others	Total
A			B	C	D	E	F	G	H	I
738	3	Trans Labor					81.4%	18.6%	0.0%	100.0%
739		Total Transmission Labor					6,913,292	1,582,784	-	8,496,076
740										
741	4	Trans RR					94.4%	5.6%	0.0%	100.0%
742		Revenue Requirement Associated with Transmission, Excluding Transmission by Others and Other Revenue					64,981,444	3,849,443	-	68,830,887
743		Revenue Requirement Associated with Transmission, Excluding Other Revenue					64,981,444	3,849,443	65,915,251	
744		Remove Transmission by Others					-	-	(65,915,251)	
745										
746	5	Trans Infrastructure DA					100.0%	0.0%	0.0%	100.0%
747		Direct Assignment to Transmission Infrastructure					1			1
748										
749	6	Trans O&M EXAG					86.3%	13.7%	0.0%	100.0%
750		Total Transmission O&M, Excluding A&G and Transmission by Others					10,271,447	1,632,624	-	11,904,071
751		Total Transmission O&M, Excluding A&G					10,271,447	1,632,624	65,915,251	
752		Remove Transmission by Others					-	-	(65,915,251)	
753										
754	7	Trans General Plnt - Net					81.4%	18.6%	0.0%	100.0%
755		Net General Plant within Transmission Function					13,333,345	3,052,642	-	16,385,987
756										
757	8	Trans Plant - Net					100.0%	0.0%	0.0%	100.0%
758							259,173,086	-	-	259,173,086
759										
760	9	T Trans Plant - Depr					97.2%	2.8%	0.0%	100.0%
761		Total Depreciation for Transmission Plant In Service, Including General Plant					12,733,716	362,411	-	13,096,126
762										

Test Year Revenue Requirement - Distribution

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Distributior

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related				
						Primary Subs, P&C	Secondary P&C	Transformers	Services	Load Dispatch
A		B	C	D	E	F	G	H	I	J
78										
79	**Total Power Production Expense**			$ -		$ -	$ -	$ -	$ -	$ -
80										
101										
102	**Total Transmission Expenses**			$ -		$ -	$ -	$ -	$ -	$ -
103										
104	**Distribution Expenses**									
105	**Operation**									
106	Operations Supervision and Engineering	580	Functional Unbundling	$ 7,846,426	580 Op Supervision	$ 3,472,551	$ 1,676,167	$ 131,684	$ 10,753	$ 668,053
107	Load Dispatching	581	Functional Unbundling	2,161,146	D Load Dispatch	-	-	-	-	2,161,146
108	Station Expenses	582	Functional Unbundling	1,215,039	Primary	1,215,039	-	-	-	-
109	Overhead Line Expenses	583	Functional Unbundling	8,147,529	Overhead P&C	6,149,784	1,997,744	-	-	-
110	Underground Line Expenses	584	Functional Unbundling	3,128,300	Underground	1,453,475	1,674,825	-	-	-
111	Street Lighting	585	Functional Unbundling	389,156	Dist Lighting	-	-	-	-	-
112	Meter Expenses	586	Functional Unbundling	3,263,817	Meters	-	-	-	-	-
113	Customer Installation Expenses	587	Functional Unbundling	135,513	Services	-	-	-	135,513	-
114	Miscellaneous Distribution Expenses	588	Functional Unbundling	4,041,605	Dist Plant - Net	2,002,186	838,658	613,109	50,063	-
115	Rents	589	Functional Unbundling	627	Primary	627	-	-	-	-
116				$ 30,329,157		$ 14,293,662	$ 6,187,394	$ 744,793	$ 196,328	$ 2,829,200
117										
118	**Maintenance**									
119	Maintenance Supervision and Engineering	590	Functional Unbundling	$ 147,276	590 Maint Supervision	$ 91,568	$ 16,064	$ 5,737	$ 445	$ -
120	Maintenance of Structures	591	Functional Unbundling	104,947	Primary	104,947	-	-	-	-
121	Maintenance of Station Equipment	592	Functional Unbundling	2,923,299	Primary	2,923,299	-	-	-	-
122	Maintenance of Overhead Lines	593	Functional Unbundling	12,491,933	Overhead P&C	9,428,957	3,062,976	-	-	-
123	Maintenance of Underground Lines	594	Functional Unbundling	199,921	Underground	92,887	107,033	-	-	-
124	Maintenance of Line Transformers	595	Functional Unbundling	8,487	Transformers	-	-	8,487	-	-
125	Maintenance of Street Lighting and Signal Systems	596	Functional Unbundling	1,501,335	Dist Lighting	-	-	-	-	-
126	Maintenance of Meters	597	Functional Unbundling	79,995	Meters	-	-	-	-	-
127	Maintenance of Miscellaneous Distribution Plant	598	Functional Unbundling	1,256,171	Dist Plant - Net	622,299	260,663	190,560	15,560	-
128				$ 18,713,363		$ 13,263,956	$ 3,446,736	$ 204,784	$ 16,005	$ -
129										
130	**Total Distribution Expenses**			**$ 49,042,519**		**$ 27,557,619**	**$ 9,634,131**	**$ 949,577**	**$ 212,333**	**$ 2,829,200**
131										
152										
153	**Total Customer and Information Expenses**			$ -		$ -	$ -	$ -	$ -	$ -
154										
155	**General and Administrative Expenses**									
156	Administrative and General Salaries	920	Functional Unbundling	$ 8,519,743	Dist Labor	$ 4,025,607	$ 1,671,174	$ 174,548	$ 14,024	$ 604,179
157	Office Supplies and Expenses	921	Functional Unbundling	5,883,784	Dist Labor	2,780,108	1,154,122	120,544	9,685	417,250
158	Administrative Expense Transferred	922	Functional Unbundling	368,475	Dist Labor	174,106	72,277	7,549	607	26,130
159	Outside Services Employed	923	Functional Unbundling	1,199,951	Dist O&M EXAG	674,268	235,724	23,234	5,195	69,224
160	Property Insurance	924	Functional Unbundling	532,369	Dist Plant - Net	263,732	110,470	80,760	6,594	-
161	Injuries and Damages	925	Functional Unbundling	721,372	Dist Labor	340,851	141,499	14,779	1,187	51,156
162	Employee Pension and Benefits	926	Functional Unbundling	173,797	Dist Labor	82,120	34,091	3,561	286	12,325
163	Regulatory Commission Expense	928	Functional Unbundling	464,281	Dist RR	238,709	100,804	42,188	(3,202)	13,243
164	General Expenses	930	Functional Unbundling	5,777,327	Dist Labor	2,729,806	1,133,240	118,363	9,510	409,700
165	Rents	931	Functional Unbundling	690,548	Dist Labor	326,286	135,453	14,148	1,137	48,970
166	Maintenance of General Plant	935	Functional Unbundling	22,537	Dist General Plnt - Net	10,649	4,421	462	37	1,598
167				$ 24,354,184		$ 11,646,241	$ 4,793,276	$ 600,135	$ 45,061	$ 1,653,777
168										
169	**Total Operations & Maintenance Expenses**			**$ 73,396,703**		**$ 39,203,860**	**$ 14,427,407**	**$ 1,549,712**	**$ 257,394**	**$ 4,482,976**
170										
171	**Depreciation & Amortization of CIAC**									
172	Depreciation Expense	403	Functional Unbundling	$ 42,487,851	T Dist Plant - Depr	$ 20,012,303	$ 9,506,081	$ 5,313,334	$ 1,064,187	$ 328,012
173	Amortization of CIAC		Functional Unbundling	(5,158,416)	T Dist Plant - Depr	(2,429,678)	(1,154,126)	(645,088)	(129,202)	(39,824)

Test Year Revenue Requirement - Distribution

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Distributior

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Primary Subs, P&C	Demand Related: Secondary P&C	Demand Related: Transformers	Demand Related: Services	Demand Related: Load Dispatch
A		B	C	D	E	F	G	H	I	J
174				$ 37,329,434		$ 17,582,625	$ 8,351,955	$ 4,668,247	$ 934,985	$ 288,188
175										
176	**Debt Service**		Functional Unbundling	$ 49,568,057	Dist Plant - Net	$ 24,555,706	$ 10,285,674	$ 7,519,440	$ 613,993	$ -
177										
178	**General Fund Transfer**	421.5	Functional Unbundling	$ 15,549,336	Dist RR	$ 7,994,664	$ 3,376,055	$ 1,412,916	$ (107,230)	$ 443,529
179										
180	**Margin**		Functional Unbundling	$ 4,835,490	T Dist Plant - Depr	$ 2,277,575	$ 1,081,875	$ 604,704	$ 121,114	$ 37,331
181										
182	**Sub-Total Revenue Requirement**			$ 180,679,020		$ 91,614,431	$ 37,522,966	$ 15,755,018	$ 1,820,255	$ 5,252,024
183										
184	**Other Expenses**									
185	Misc Service Revenue	451	Functional Unbundling	$ -	Dist RR	$ -	$ -	$ -	$ -	$ -
186	Donations	426	Functional Unbundling	-	Dist RR	-	-	-	-	-
187	Taxes Other Than Income	408	Functional Unbundling	4,004	Dist RR	2,059	869	364	(28)	114
188	Expenses - Non-utility operations	417	Functional Unbundling	-	Dist RR	-	-	-	-	-
189	Franchise Fees		Functional Unbundling	1,123,778	Dist RR	577,789	243,993	102,114	(7,750)	32,055
190				$ 1,127,782		$ 579,847	$ 244,863	$ 102,478	$ (7,777)	$ 32,169
191										
192	**Other (Non-Rate) Revenue**									
193	Miscellaneous Nonoperating Income	421	Functional Unbundling	$ 1,859	Dist RR	$ 956	$ 404	$ 169	$ (13)	$ 53
194	Other Revenue		Functional Unbundling	9,352,089	Dist Other Rev	3,526,981	324,653	187,119	3,001,747	365,094
195	Off-System Sales		Functional Unbundling	-	Dist RR	-	-	-	-	-
196				$ 9,353,948		$ 3,527,936	$ 325,056	$ 187,288	$ 3,001,734	$ 365,147
197										
198	**Total Revenue Requirement**			$ 172,452,854		$ 88,666,341	$ 37,442,772	$ 15,670,208	$ (1,189,256)	$ 4,919,046
199										
200	**System Retail Sales (MWH)**		Functional Unbundling	11,813,939						
201	Average Rate ($/MWh)			$ 14.60						
202										
203										
204										
205	**Gross Plant In Service**									
257	Distribution Plant									
258	Land & Land Rights	360	WP 2	$ 6,461,585	Primary	$ 6,461,585	$ -	$ -	$ -	$ -
259	Structures & Improvements	361	WP 2	28,303,272	Primary	28,303,272	-	-	-	-
260	Station Equipment	362	WP 2	175,080,889	Primary	175,080,889	-	-	-	-
261	Storage Equipment	363	WP 2	36,895	363 Storage	17,772	8,038	5,557	975	-
262	Poles, Towers & Fixtures	364	WP 2	157,134,675	Overhead P&C	118,605,826	38,528,849	-	-	-
263	OH Conductors & Devices	365	WP 2	180,468,419	Overhead P&C	136,218,221	44,250,198	-	-	-
264	UG Conduit	366	WP 2	150,110,871	Underground	69,744,700	80,366,171	-	-	-
265	UG Conductors & Devices	367	WP 2	241,618,710	Underground	112,261,186	129,357,523	-	-	-
266	Line Transformers	368	WP 2	202,194,513	Transformers	-	-	202,194,513	-	-
267	Services	369	WP 2	32,698,096	Services	-	-	-	32,698,096	-
268	Meters	370	WP 2	87,688,116	Meters	-	-	-	-	-
269	Installation on Customers' Prem	371	WP 2	27,630	Services	-	-	-	27,630	-
270	Leased Property on Customers' Premises	372	WP 2	2,738,404	Services	-	-	-	2,738,404	-
271	Streetlighting & Signal Systems	373	WP 2	77,997,340	Dist Lighting	-	-	-	-	-
272				$ 1,342,559,415		$ 646,693,453	$ 292,510,779	$ 202,200,069	$ 35,465,104	$ -
273										
274	**Subtotal Plant in Service Before General Plant**			$ 1,342,559,415		$ 646,693,453	$ 292,510,779	$ 202,200,069	$ 35,465,104	$ -
275										
276	General Plant									
277	Land & Land Rights	389	WP 2	$ 9,536,230	Dist Labor	$ 4,505,900	$ 1,870,561	$ 195,374	$ 15,697	$ 676,264
278	Structures & Improvements	390	WP 2	25,221,944	Dist Labor	11,917,452	4,947,362	516,735	41,517	1,788,620
279	Office Furniture & Equipment	391	WP 2	20,874,193	Dist Labor	9,863,125	4,094,537	427,660	34,360	1,480,298
280	Transportation Equipment	392	WP 2	15,918,737	Dist Labor	7,521,656	3,122,509	326,135	26,203	1,128,881

Test Year Revenue Requirement - Distribution

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Distributior

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related Primary Subs, P&C	Secondary P&C	Transformers	Services	Load Dispatch
A		B	C	D	E	F	G	H	I	J
281	Stores Equipment	393	WP 2	222,489	Dist Labor	105,127	43,642	4,558	366	15,778
282	Tools, Shop & Garage Equipment	394	WP 2	2,876,064	Dist Labor	1,358,950	564,149	58,923	4,734	203,957
283	Laboratory Equipment	395	WP 2	278,994	Dist Labor	131,825	54,725	5,716	459	19,785
284	Power Operated Equipment	396	WP 2	659,448	Dist Labor	311,591	129,353	13,510	1,085	46,765
285	Communications Equipment	397	WP 2	12,856,915	Dist Labor	6,074,935	2,521,923	263,406	21,163	911,751
286	Miscellaneous Equipment	398	WP 2	100,621	Dist Labor	47,544	19,737	2,061	166	7,136
287	Other Tangible Property	399	WP 2	-	Dist Labor	-	-	-	-	-
288				$ 88,545,635		$ 41,838,107	$ 17,368,498	$ 1,814,080	$ 145,752	$ 6,279,233
289										
290	**Total Plant in Service - Gross**			**$ 1,431,105,050**		**$ 688,531,559**	**$ 309,879,277**	**$ 204,014,150**	**$ 35,610,857**	**$ 6,279,233**
291										
292										
293										
294	**Accumulated Depreciation**									
346	Distribution Plant									
347	Land & Land Rights	360	WP 2	$ -	Primary	$ -	$ -	$ -	$ -	$ -
348	Structures & Improvements	361	WP 2	13,004,074	Primary	13,004,074	-	-	-	-
349	Station Equipment	362	WP 2	57,594,514	Primary	57,594,514	-	-	-	-
350	Storage Equipment	363	WP 2	18,488	363 Storage	8,905	4,028	2,784	488	-
351	Poles, Towers & Fixtures	364	WP 2	73,689,580	Overhead P&C	55,621,164	18,068,416	-	-	-
352	OH Conductors & Devices	365	WP 2	79,070,916	Overhead P&C	59,683,016	19,387,900	-	-	-
353	UG Conduit	366	WP 2	80,139,771	Underground	37,234,640	42,905,131	-	-	-
354	UG Conductors & Devices	367	WP 2	101,929,307	Underground	47,358,522	54,570,785	-	-	-
355	Line Transformers	368	WP 2	87,000,937	Transformers	-	-	87,000,937	-	-
356	Services	369	WP 2	23,989,499	Services	-	-	-	23,989,499	-
357	Meters	370	WP 2	30,934,227	Meters	-	-	-	-	-
358	Installation on Customers' Prem	371	WP 2	8,347	Services	-	-	-	8,347	-
359	Leased Property on Customers' Premises	372	WP 2	2,060,517	Services	-	-	-	2,060,517	-
360	Streetlighting & Signal Systems	373	WP 2	33,746,289	Dist Lighting	-	-	-	-	-
361				$ 583,186,465		$ 270,504,836	$ 134,936,260	$ 87,003,722	$ 26,058,851	$ -
362										
363	**Subtotal Plant in Service Before General Plant**			**$ 583,186,465**		**$ 270,504,836**	**$ 134,936,260**	**$ 87,003,722**	**$ 26,058,851**	**$ -**
364										
365	General Plant									
366	Land & Land Rights	389	WP 2	$ -	Dist Labor	$ -	$ -	$ -	$ -	$ -
367	Structures & Improvements	390	WP 2	13,081,053	Dist Labor	6,180,841	2,565,889	267,998	21,532	927,646
368	Office Furniture & Equipment	391	WP 2	8,251,731	Dist Labor	3,898,970	1,618,602	169,057	13,583	585,173
369	Transportation Equipment	392	WP 2	9,413,844	Dist Labor	4,448,072	1,846,554	192,866	15,496	667,585
370	Stores Equipment	393	WP 2	218,973	Dist Labor	103,466	42,952	4,486	360	15,529
371	Tools, Shop & Garage Equipment	394	WP 2	1,328,019	Dist Labor	627,493	260,495	27,208	2,186	94,177
372	Laboratory Equipment	395	WP 2	149,255	Dist Labor	70,523	29,277	3,058	246	10,584
373	Power Operated Equipment	396	WP 2	121,864	Dist Labor	57,581	23,904	2,497	201	8,642
374	Communications Equipment	397	WP 2	9,782,459	Dist Labor	4,622,244	1,918,859	200,418	16,103	693,725
375	Miscellaneous Equipment	398	WP 2	68,954	Dist Labor	32,581	13,526	1,413	114	4,890
376	Other Tangible Property	399	WP 2	-	Dist Labor	-	-	-	-	-
377				$ 42,416,152		$ 20,041,773	$ 8,320,058	$ 869,002	$ 69,820	$ 3,007,951
378										
379	**Total Plant in Service - Accumulated Depreciation**			**$ 625,602,617**		**$ 290,546,608**	**$ 143,256,318**	**$ 87,872,723**	**$ 26,128,671**	**$ 3,007,951**
380										
381										
382										
383	**Net Plant In Service**									
435	Distribution Plant									
436	Land & Land Rights	360	WP 2	$ 6,461,585	Primary	$ 6,461,585	$ -	$ -	$ -	$ -
437	Structures & Improvements	361	WP 2	15,299,198	Primary	15,299,198	-	-	-	-
438	Station Equipment	362	WP 2	117,486,376	Primary	117,486,376	-	-	-	-

Test Year Revenue Requirement - Distribution

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Distributior

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Primary Subs, P&C	Secondary P&C	Transformers	Services	Load Dispatch
A		B	C	D	E	F	G	H	I	J
439	Storage Equipment	363	WP 2	18,407	363 Storage	8,866	4,010	2,772	486	-
440	Poles, Towers & Fixtures	364	WP 2	83,445,095	Overhead P&C	62,984,662	20,460,433	-	-	-
441	OH Conductors & Devices	365	WP 2	101,397,503	Overhead P&C	76,535,206	24,862,298	-	-	-
442	UG Conduit	366	WP 2	69,971,100	Underground	32,510,060	37,461,040	-	-	-
443	UG Conductors & Devices	367	WP 2	139,689,403	Underground	64,902,665	74,786,738	-	-	-
444	Line Transformers	368	WP 2	115,193,576	Transformers	-	-	115,193,576	-	-
445	Services	369	WP 2	8,708,597	Services	-	-	-	8,708,597	-
446	Meters	370	WP 2	56,753,889	Meters	-	-	-	-	-
447	Installation on Customers' Prem	371	WP 2	19,283	Services	-	-	-	19,283	-
448	Leased Property on Customers' Premises	372	WP 2	677,887	Services	-	-	-	677,887	-
449	Streetlighting & Signal Systems	373	WP 2	44,251,052	Dist Lighting	-	-	-	-	-
450				$ 759,372,950		$ 376,188,617	$ 157,574,519	$ 115,196,348	$ 9,406,254	$ -
451										
452	**Subtotal Plant in Service Before General Plant**			**$ 759,372,950**		**$ 376,188,617**	**$ 157,574,519**	**$ 115,196,348**	**$ 9,406,254**	**$ -**
453										
454	General Plant									
455	Land & Land Rights	389	WP 2	$ 9,536,230	Dist Labor	$ 4,505,900	$ 1,870,561	$ 195,374	$ 15,697	$ 676,264
456	Structures & Improvements	390	WP 2	12,140,891	Dist Labor	5,736,611	2,381,473	248,737	19,985	860,974
457	Office Furniture & Equipment	391	WP 2	12,622,462	Dist Labor	5,964,155	2,475,935	258,603	20,777	895,125
458	Transportation Equipment	392	WP 2	6,504,893	Dist Labor	3,073,584	1,275,955	133,269	10,707	461,296
459	Stores Equipment	393	WP 2	3,515	Dist Labor	1,661	690	72	6	249
460	Tools, Shop & Garage Equipment	394	WP 2	1,548,045	Dist Labor	731,457	303,654	31,716	2,548	109,780
461	Laboratory Equipment	395	WP 2	129,739	Dist Labor	61,302	25,449	2,658	214	9,200
462	Power Operated Equipment	396	WP 2	537,584	Dist Labor	254,010	105,449	11,014	885	38,123
463	Communications Equipment	397	WP 2	3,074,456	Dist Labor	1,452,691	603,064	62,988	5,061	218,026
464	Miscellaneous Equipment	398	WP 2	31,668	Dist Labor	14,963	6,212	649	52	2,246
465	Other Tangible Property	399	WP 2	-	Dist Labor	-	-	-	-	-
466				$ 46,129,483		$ 21,796,334	$ 9,048,440	$ 945,079	$ 75,932	$ 3,271,282
467										
468	**Total Plant in Service - Net**			**$ 805,502,433**		**$ 397,984,951**	**$ 166,622,959**	**$ 116,141,426**	**$ 9,482,186**	**$ 3,271,282**
469										
470										
471										
472	**Depreciation Expense**									
524	Distribution Plant									
525	Land & Land Rights	360	WP 2	$ -	Primary	$ -	$ -	$ -	$ -	$ -
526	Structures & Improvements	361	WP 2	993,226	Primary	993,226	-	-	-	-
527	Station Equipment	362	WP 2	4,139,256	Primary	4,139,256	-	-	-	-
528	Storage Equipment	363	WP 2	3,244	363 Storage	1,563	707	489	86	-
529	Poles, Towers & Fixtures	364	WP 2	4,601,750	Overhead P&C	3,473,418	1,128,332	-	-	-
530	OH Conductors & Devices	365	WP 2	5,049,315	Overhead P&C	3,811,241	1,238,074	-	-	-
531	UG Conduit	366	WP 2	4,487,640	Underground	2,085,053	2,402,587	-	-	-
532	UG Conductors & Devices	367	WP 2	7,152,122	Underground	3,323,028	3,829,094	-	-	-
533	Line Transformers	368	WP 2	5,218,083	Transformers	-	-	5,218,083	-	-
534	Services	369	WP 2	976,365	Services	-	-	-	976,365	-
535	Meters	370	WP 2	3,080,223	Meters	-	-	-	-	-
536	Installation on Customers' Prem	371	WP 2	1,829	Services	-	-	-	1,829	-
537	Leased Property on Customers' Premises	372	WP 2	78,293	Services	-	-	-	78,293	-
538	Streetlighting & Signal Systems	373	WP 2	2,081,101	Dist Lighting	-	-	-	-	-
539				$ 37,862,447		$ 17,826,784	$ 8,598,794	$ 5,218,571	$ 1,056,573	$ -
540										
541	**Subtotal Plant in Service Before General Plant**			**$ 37,862,447**		**$ 17,826,784**	**$ 8,598,794**	**$ 5,218,571**	**$ 1,056,573**	**$ -**
542										
543	General Plant									
544	Land & Land Rights	389	WP 2	$ -	Dist Labor	$ -	$ -	$ -	$ -	$ -
545	Structures & Improvements	390	WP 2	691,045	Dist Labor	326,521	135,551	14,158	1,138	49,006

Test Year Revenue Requirement - Distribution

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Distributior

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Primary Subs, P&C	Secondary P&C	Transformers	Services	Load Dispatch
A		B	C	D	E	F	G	H	I	J
546	Office Furniture & Equipment	391	WP 2	1,714,948	Dist Labor	810,318	336,392	35,135	2,823	121,616
547	Transportation Equipment	392	WP 2	1,185,365	Dist Labor	560,089	232,513	24,285	1,951	84,060
548	Stores Equipment	393	WP 2	248	Dist Labor	117	49	5	0	18
549	Tools, Shop & Garage Equipment	394	WP 2	191,042	Dist Labor	90,268	37,474	3,914	314	13,548
550	Laboratory Equipment	395	WP 2	21,668	Dist Labor	10,238	4,250	444	36	1,537
551	Power Operated Equipment	396	WP 2	12,904	Dist Labor	6,097	2,531	264	21	915
552	Communications Equipment	397	WP 2	802,956	Dist Labor	379,399	157,502	16,451	1,322	56,942
553	Miscellaneous Equipment	398	WP 2	5,227	Dist Labor	2,470	1,025	107	9	371
554	Other Tangible Property	399	WP 2	-	Dist Labor	-	-	-	-	-
555				$ 4,625,404		$ 2,185,519	$ 907,287	$ 94,763	$ 7,614	$ 328,012
556										
557	**Total Plant Depreciation**			**$ 42,487,850**		**$ 20,012,303**	**$ 9,506,081**	**$ 5,313,334**	**$ 1,064,187**	**$ 328,012**
558										
559										
560										
561										
562										
563	**Labor**									
564										
636										
637	**Total Power Production Expense**			$ -		$ -	$ -	$ -	$ -	$ -
638										
659										
660	**Total Transmission Expenses**			$ -		$ -	$ -	$ -	$ -	$ -
661										
662	**Distribution Expenses**									
663	**Operation**									
664	Operations Supervision and Engineering	580	WP 3.1	$ 7,760,072	580 Op Supervision	$ 3,434,334	$ 1,657,720	$ 130,235	$ 10,634	$ 660,701
665	Load Dispatching	581	WP 3.1	1,198,111	D Load Dispatch	-	-	-	-	1,198,111
666	Station Expenses	582	WP 3.1	47,661	Primary	47,661	-	-	-	-
667	Overhead Line Expenses	583	WP 3.1	5,683,357	Overhead P&C	4,289,819	1,393,538	-	-	-
668	Underground Line Expenses	584	WP 3.1	2,408,599	Underground	1,119,086	1,289,513	-	-	-
669	Street Lighting	585	WP 3.1	300,672	Dist Lighting	-	-	-	-	-
670	Meter Expenses	586	WP 3.1	2,876,854	Meters	-	-	-	-	-
671	Customer Installation Expenses	587	WP 3.1	-	Services	-	-	-	-	-
672	Miscellaneous Distribution Expenses	588	WP 3.1	1,556,809	Dist Plant - Net	771,234	323,047	236,167	19,284	-
673	Rents	589	WP 3.1	-		-	-	-	-	-
674				$ 21,832,135		$ 9,662,134	$ 4,663,818	$ 366,402	$ 29,918	$ 1,858,812
675										
676	**Maintenance**									
677	Maintenance Supervision and Engineering	590	WP 3.1	$ 142,290	590 Maint Supervision	$ 88,468	$ 15,520	$ 5,543	$ 430	$ -
678	Maintenance of Structures	591	WP 3.1	-	Primary	-	-	-	-	-
679	Maintenance of Station Equipment	592	WP 3.1	1,360,500	Primary	1,360,500	-	-	-	-
680	Maintenance of Overhead Lines	593	WP 3.1	1,009,486	Overhead P&C	761,964	247,522	-	-	-
681	Maintenance of Underground Lines	594	WP 3.1	476	Underground	221	255	-	-	-
682	Maintenance of Line Transformers	595	WP 3.1	8,330	Transformers	-	-	8,330	-	-
683	Maintenance of Street Lighting and Signal Systems	596	WP 3.1	745,315	Dist Lighting	-	-	-	-	-
684	Maintenance of Meters	597	WP 3.1	79,995	Meters	-	-	-	-	-
685	Maintenance of Miscellaneous Distribution Plant	598	WP 3.1	1,033,220	Dist Plant - Net	511,851	214,399	156,739	12,798	-
686				$ 4,379,612		$ 2,723,004	$ 477,696	$ 170,612	$ 13,228	$ -
687										
688	**Total Distribution Expenses**			**$ 26,211,747**		**$ 12,385,138**	**$ 5,141,515**	**$ 537,014**	**$ 43,146**	**$ 1,858,812**
689										
710										
711	**Total Customer and Information Expenses**			$ -		$ -	$ -	$ -	$ -	$ -
712										

Test Year Revenue Requirement - Distribution

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Distributior

Line No.		Description	FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Primary Subs, P&C	Secondary P&C	Transformers	Services	Load Dispatch
A			B	C	D	E	F	G	H	I	J
713		**General and Administrative Expenses**									
714		Administrative and General Salaries	920	WP 3.1	$ 12,515,425	Dist Labor	$ 5,913,580	$ 2,454,939	$ 256,410	$ 20,601	$ 887,534
715		Office Supplies and Expenses	921	WP 3.1	3,488	Dist Labor	1,648	684	71	6	247
716		Administrative Expense Transferred	922	WP 3.1	-	Dist Labor	-	-	-	-	-
717		Outside Services Employed	923	WP 3.1	651	Dist O&M EXAG	366	128	13	3	38
718		Property Insurance	924	WP 3.1	-	Dist Plant - Net	-	-	-	-	-
719		Injuries and Damages	925	WP 3.1	-	Dist Labor	-	-	-	-	-
720		Employee Pension and Benefits	926	WP 3.1	-	Dist Labor	-	-	-	-	-
721		Regulatory Commission Expense	928	WP 3.1	-	Dist RR	-	-	-	-	-
722		General Expenses	930	WP 3.1	294,875	Dist Labor	139,329	57,841	6,041	485	20,911
723		Rents	931	WP 3.1	-	Dist Labor	-	-	-	-	-
724		Maintenance of General Plant	935	WP 3.1	-	Dist General Plnt - Net	-	-	-	-	-
725					$ 12,814,439		$ 6,054,923	$ 2,513,592	$ 262,535	$ 21,095	$ 908,730
726											
727		**Total Electric Labor**			**$ 39,026,186**		**$ 18,440,061**	**$ 7,655,107**	**$ 799,549**	**$ 64,242**	**$ 2,767,542**
728											
729											
730											
731		**Allocation Factors**									
732	1	D Load Dispatch					0.0%	0.0%	0.0%	0.0%	100.0%
733		Direct Assignment to Load Dispatch within the Distribution Function									1
734											
735	2	Primary					100.0%	0.0%	0.0%	0.0%	0.0%
736		Direct Assignment to Primary					1				
737											
738	3	Dist General Plnt - Net					47.3%	19.6%	2.0%	0.2%	7.1%
739		Net General Plant within Distribution Function					21,796,334	9,048,440	945,079	75,932	3,271,282
740											
741	4	Transformers					0.0%	0.0%	100.0%	0.0%	0.0%
742		Direct Assignment to Transformers							1		
743											
744	5	Meters					0.0%	0.0%	0.0%	0.0%	0.0%
745		Direct Assignment to Meters									
746											
747	6	Services					0.0%	0.0%	0.0%	100.0%	0.0%
748		Direct Assignment to Services								1	
749											
750	7	Dist Lighting					0.0%	0.0%	0.0%	0.0%	0.0%
751		Direct Assignment to City-Owned Lighting (Street and Signal Lighting)									
752											
753	8	Secondary					0.0%	100.0%	0.0%	0.0%	0.0%
754		Direct Assignment to Secondary						1			
755											
756	9	580 Op Supervision					44.3%	21.4%	1.7%	0.1%	8.5%
757							6,227,799	3,006,098	236,167	19,284	1,198,111
758											
759	10	590 Maint Supervision					62.2%	10.9%	3.9%	0.3%	0.0%
760							2,634,536	462,176	165,069	12,798	-
761											
762	11	363 Storage					48.2%	21.8%	15.1%	2.6%	0.0%
763		Gross Distribution Plant In Service, Excluding FERC 363					646,675,681	292,502,741	202,194,513	35,464,130	-
764											
765	12	Dist Plant - Net					49.5%	20.8%	15.2%	1.2%	0.0%
766		Net Distribution Plant in Service					376,188,617	157,574,519	115,196,348	9,406,254	-
767											
768	13	Dist Labor					47.3%	19.6%	2.0%	0.2%	7.1%
769		Total Distribution Labor, Including Direct Assignments					12,385,138	5,141,515	537,014	43,146	1,858,812

Test Year Revenue Requirement - Distribution

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Distributior

Line No.			FERC Account	Source Reference	Test Year	Allocation Basis	Demand Related: Primary Subs, P&C	Secondary P&C	Transformers	Services	Load Dispatch
A			B	C	D	E	F	G	H	I	J
770											
771	14	Dist RR					51.4%	21.7%	9.1%	-0.7%	2.9%
772		Revenue Requirement Associated with Distribution, Including Direct Assignments					88,666,341	37,442,772	15,670,208	(1,189,256)	4,919,046
773											
774	15	Overhead P&C	WP 34 - Dist Alloc				75.5%	24.5%	0.0%	0.0%	0.0%
775							1,892	615			
776											
777	16	Underground	WP 34 - Dist Alloc				46.5%	53.5%	0.0%	0.0%	0.0%
778							2,075	2,391			
779											
780	17	T Dist Plant - Depr					47.1%	22.4%	12.5%	2.5%	0.8%
781		Total Depreciation for Distribution Plant In Service, Including General Plant					20,012,303	9,506,081	5,313,334	1,064,187	328,012
782											
783	18	Dist O&M EXAG					56.2%	19.6%	1.9%	0.4%	5.8%
784		Total Distribution O&M, Excluding A&G					27,557,619	9,634,131	949,577	212,333	2,829,200
785											
786	19	Dist Other Rev	WP 15 - Other Rev				37.7%	3.5%	2.0%	32.1%	3.9%
787		Other Revenue Summary			$ 9,352,089		$ 3,526,981	$ 324,653	$ 187,119	$ 3,001,747	$ 365,094
788		Primary Related Direct Assignment			$ 2,915,919	Primary	$ 2,915,919	$ -	$ -	$ -	$ -
789		Secondary Related Direct Assignment			$ 68,697	Secondary	$ -	$ 68,697	$ -	$ -	$ -
790		Meter Related Direct Assignment			$ 1,752,839	Meters	$ -	$ -	$ -	$ -	$ -
791		Services Related Direct Assignment			$ 2,986,468	Services	$ -	$ -	$ -	$ 2,986,468	$ -
792		Load Dispatch Related Direct Assignment			$ 365,094	D Load Dispatch	$ -	$ -	$ -	$ -	$ 365,094
793		Lighting Related Direct Assignment			$ 29,585	Dist Lighting	$ -	$ -	$ -	$ -	$ -
794		Remainder Allocated on Net Distribution Plant in Service			$ 1,233,487	Dist Plant - Net	$ 611,062	$ 255,956	$ 187,119	$ 15,279	$ -
788											

Test Year Revenue Requirement - Distribution

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Distributior

Line No.		FERC Account	Customer Related Meters	Direct Assignments City-Owned Lighting	Total
A		B	K	L	M
78					
79	**Total Power Production Expense**		$ -	$ -	$ -
80					
101					
102	**Total Transmission Expenses**		$ -	$ -	$ -
103					
104	**Distribution Expenses**				
105	**Operation**				
106	Operations Supervision and Engineering	580	$ 1,668,980	$ 218,237	$ 7,846,426
107	Load Dispatching	581	-	-	2,161,146
108	Station Expenses	582	-	-	1,215,039
109	Overhead Line Expenses	583	-	-	8,147,529
110	Underground Line Expenses	584	-	-	3,128,300
111	Street Lighting	585	-	389,156	389,156
112	Meter Expenses	586	3,263,817	-	3,263,817
113	Customer Installation Expenses	587	-	-	135,513
114	Miscellaneous Distribution Expenses	588	302,067	235,523	4,041,605
115	Rents	589	-	-	627
116			$ 5,234,864	$ 842,916	$ 30,329,157
117					
118	**Maintenance**				
119	Maintenance Supervision and Engineering	590	$ 5,464	$ 27,997	$ 147,276
120	Maintenance of Structures	591	-	-	104,947
121	Maintenance of Station Equipment	592	-	-	2,923,299
122	Maintenance of Overhead Lines	593	-	-	12,491,933
123	Maintenance of Underground Lines	594	-	-	199,921
124	Maintenance of Line Transformers	595	-	-	8,487
125	Maintenance of Street Lighting and Signal Systems	596	-	1,501,335	1,501,335
126	Maintenance of Meters	597	79,995	-	79,995
127	Maintenance of Miscellaneous Distribution Plant	598	93,885	73,203	1,256,171
128			$ 179,345	$ 1,602,536	$ 18,713,363
129					
130	**Total Distribution Expenses**		**$ 5,414,209**	**$ 2,445,451**	**$ 49,042,519**
131					
152					
153	**Total Customer and Information Expenses**		$ -	$ -	$ -
154					
155	**General and Administrative Expenses**				
156	Administrative and General Salaries	920	$ 1,562,223	$ 467,988	$ 8,519,743
157	Office Supplies and Expenses	921	1,078,880	323,195	5,883,784
158	Administrative Expense Transferred	922	67,565	20,240	368,475
159	Outside Services Employed	923	132,472	59,834	1,199,951
160	Property Insurance	924	39,789	31,024	532,369
161	Injuries and Damages	925	132,274	39,625	721,372
162	Employee Pension and Benefits	926	31,868	9,547	173,797
163	Regulatory Commission Expense	928	46,059	26,480	464,281
164	General Expenses	930	1,059,360	317,347	5,777,327
165	Rents	931	126,622	37,932	690,548
166	Maintenance of General Plant	935	4,132	1,238	22,537
167			$ 4,281,246	$ 1,334,448	$ 24,354,184
168					
169	**Total Operations & Maintenance Expenses**		**$ 9,695,455**	**$ 3,779,900**	**$ 73,396,703**
170					
171	**Depreciation & Amortization of CIAC**				
172	Depreciation Expense	403	$ 3,928,572	$ 2,335,362	$ 42,487,851
173	Amortization of CIAC		(476,965)	(283,534)	(5,158,416)

Test Year Revenue Requirement - Distribution

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Distributior

Line No.		FERC Account	Customer Related Meters	Direct Assignments City-Owned Lighting	Total
A		B	K	L	M
174			**$ 3,451,607**	**$ 2,051,828**	**$ 37,329,434**
175					
176	**Debt Service**		**$ 3,704,688**	**$ 2,888,556**	**$ 49,568,057**
177					
178	**General Fund Transfer**	421.5	**$ 1,542,563**	**$ 886,839**	**$ 15,549,336**
179					
180	**Margin**		**$ 447,106**	**$ 265,785**	**$ 4,835,490**
181					
182	**Sub-Total Revenue Requirement**		**$ 18,841,419**	**$ 9,872,908**	**$ 180,679,020**
183					
184	**Other Expenses**				
185	Misc Service Revenue	451	$ -	$ -	$ -
186	Donations	426	-	-	-
187	Taxes Other Than Income	408	397	228	4,004
188	Expenses - Non-utility operations	417	-	-	-
189	Franchise Fees		111,484	64,093	1,123,778
190			**$ 111,881**	**$ 64,322**	**$ 1,127,782**
191					
192	**Other (Non-Rate) Revenue**				
193	Miscellaneous Nonoperating Income	421	$ 184	$ 106	$ 1,859
194	Other Revenue		1,845,030	101,466	9,352,089
195	Off-System Sales		-	-	-
196			**$ 1,845,214**	**$ 101,572**	**$ 9,353,948**
197					
198	**Total Revenue Requirement**		**$ 17,108,086**	**$ 9,835,657**	**$ 172,452,854**
199					
200	**System Retail Sales (MWH)**				
201	Average Rate ($/MWh)				
202					
203					
204					
205	**Gross Plant In Service**				
257	Distribution Plant				
258	Land & Land Rights	360	$ -	$ -	$ 6,461,585
259	Structures & Improvements	361	-	-	28,303,272
260	Station Equipment	362	-	-	175,080,889
261	Storage Equipment	363	2,410	2,143	36,895
262	Poles, Towers & Fixtures	364	-	-	157,134,675
263	OH Conductors & Devices	365	-	-	180,468,419
264	UG Conduit	366	-	-	150,110,871
265	UG Conductors & Devices	367	-	-	241,618,710
266	Line Transformers	368	-	-	202,194,513
267	Services	369	-	-	32,698,096
268	Meters	370	87,688,116	-	87,688,116
269	Installation on Customers' Prem	371	-	-	27,630
270	Leased Property on Customers' Premises	372	-	-	2,738,404
271	Streetlighting & Signal Systems	373	-	77,997,340	77,997,340
272			$ 87,690,526	$ 77,999,484	$ 1,342,559,415
273					
274	**Subtotal Plant in Service Before General Plant**		**$ 87,690,526**	**$ 77,999,484**	**$ 1,342,559,415**
275					
276	General Plant				
277	Land & Land Rights	389	$ 1,748,611	$ 523,823	$ 9,536,230
278	Structures & Improvements	390	4,624,823	1,385,436	25,221,944
279	Office Furniture & Equipment	391	3,827,597	1,146,615	20,874,193
280	Transportation Equipment	392	2,918,940	874,413	15,918,737

Test Year Revenue Requirement - Distribution

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Distributior

			Customer Related	Direct Assignments	
Line No.		FERC Account	Meters	City-Owned Lighting	Total
A		B	K	L	M
281	Stores Equipment	393	40,797	12,221	222,489
282	Tools, Shop & Garage Equipment	394	527,370	157,982	2,876,064
283	Laboratory Equipment	395	51,158	15,325	278,994
284	Power Operated Equipment	396	120,920	36,223	659,448
285	Communications Equipment	397	2,357,509	706,227	12,856,915
286	Miscellaneous Equipment	398	18,450	5,527	100,621
287	Other Tangible Property	399	-	-	-
288			$ 16,236,173	$ 4,863,791	$ 88,545,635
289					
290	**Total Plant in Service - Gross**		**$ 103,926,699**	**$ 82,863,275**	**$ 1,431,105,050**
291					
292					
293					
294	**Accumulated Depreciation**				
346	Distribution Plant				
347	Land & Land Rights	360	$ -	$ -	$ -
348	Structures & Improvements	361	-	-	13,004,074
349	Station Equipment	362	-	-	57,594,514
350	Storage Equipment	363	1,208	1,074	18,488
351	Poles, Towers & Fixtures	364	-	-	73,689,580
352	OH Conductors & Devices	365	-	-	79,070,916
353	UG Conduit	366	-	-	80,139,771
354	UG Conductors & Devices	367	-	-	101,929,307
355	Line Transformers	368	-	-	87,000,937
356	Services	369	-	-	23,989,499
357	Meters	370	30,934,227	-	30,934,227
358	Installation on Customers' Prem	371	-	-	8,347
359	Leased Property on Customers' Premises	372	-	-	2,060,517
360	Streetlighting & Signal Systems	373	-	33,746,289	33,746,289
361			$ 30,935,435	$ 33,747,363	$ 583,186,465
362					
363	**Subtotal Plant in Service Before General Plant**		**$ 30,935,435**	**$ 33,747,363**	**$ 583,186,465**
364					
365	General Plant				
366	Land & Land Rights	389	$ -	$ -	$ -
367	Structures & Improvements	390	2,398,608	718,539	13,081,053
368	Office Furniture & Equipment	391	1,513,079	453,266	8,251,731
369	Transportation Equipment	392	1,726,170	517,100	9,413,844
370	Stores Equipment	393	40,152	12,028	218,973
371	Tools, Shop & Garage Equipment	394	243,512	72,948	1,328,019
372	Laboratory Equipment	395	27,368	8,199	149,255
373	Power Operated Equipment	396	22,346	6,694	121,864
374	Communications Equipment	397	1,793,761	537,348	9,782,459
375	Miscellaneous Equipment	398	12,644	3,788	68,954
376	Other Tangible Property	399	-	-	-
377			$ 7,777,639	$ 2,329,909	$ 42,416,152
378					
379	**Total Plant in Service - Accumulated Depreciation**		**$ 38,713,074**	**$ 36,077,272**	**$ 625,602,617**
380					
381					
382					
383	**Net Plant In Service**				
435	Distribution Plant				
436	Land & Land Rights	360	$ -	$ -	$ 6,461,585
437	Structures & Improvements	361	-	-	15,299,198
438	Station Equipment	362	-	-	117,486,376

Test Year Revenue Requirement - Distribution
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Distributior

Line No.		FERC Account	Customer Related Meters	Direct Assignments City-Owned Lighting	Total
A		B	K	L	M
439	Storage Equipment	363	1,202	1,069	18,407
440	Poles, Towers & Fixtures	364	-	-	83,445,095
441	OH Conductors & Devices	365	-	-	101,397,503
442	UG Conduit	366	-	-	69,971,100
443	UG Conductors & Devices	367	-	-	139,689,403
444	Line Transformers	368	-	-	115,193,576
445	Services	369	-	-	8,708,597
446	Meters	370	56,753,889	-	56,753,889
447	Installation on Customers' Prem	371	-	-	19,283
448	Leased Property on Customers' Premises	372	-	-	677,887
449	Streetlighting & Signal Systems	373	-	44,251,052	44,251,052
450			$ 56,755,092	$ 44,252,121	$ 759,372,950
451					
452	**Subtotal Plant in Service Before General Plant**		**$ 56,755,092**	**$ 44,252,121**	**$ 759,372,950**
453					
454	General Plant				
455	Land & Land Rights	389	$ 1,748,611	$ 523,823	$ 9,536,230
456	Structures & Improvements	390	2,226,215	666,896	12,140,891
457	Office Furniture & Equipment	391	2,314,518	693,349	12,622,462
458	Transportation Equipment	392	1,192,770	357,312	6,504,893
459	Stores Equipment	393	645	193	3,515
460	Tools, Shop & Garage Equipment	394	283,857	85,034	1,548,045
461	Laboratory Equipment	395	23,790	7,127	129,739
462	Power Operated Equipment	396	98,574	29,529	537,584
463	Communications Equipment	397	563,748	168,879	3,074,456
464	Miscellaneous Equipment	398	5,807	1,739	31,668
465	Other Tangible Property	399	-	-	-
466			$ 8,458,534	$ 2,533,882	$ 46,129,483
467					
468	**Total Plant in Service - Net**		**$ 65,213,626**	**$ 46,786,003**	**$ 805,502,433**
469					
470					
471					
472	**Depreciation Expense**				
524	Distribution Plant				
525	Land & Land Rights	360	$ -	$ -	$ -
526	Structures & Improvements	361	-	-	993,226
527	Station Equipment	362	-	-	4,139,256
528	Storage Equipment	363	212	188	3,244
529	Poles, Towers & Fixtures	364	-	-	4,601,750
530	OH Conductors & Devices	365	-	-	5,049,315
531	UG Conduit	366	-	-	4,487,640
532	UG Conductors & Devices	367	-	-	7,152,122
533	Line Transformers	368	-	-	5,218,083
534	Services	369	-	-	976,365
535	Meters	370	3,080,223	-	3,080,223
536	Installation on Customers' Prem	371	-	-	1,829
537	Leased Property on Customers' Premises	372	-	-	78,293
538	Streetlighting & Signal Systems	373	-	2,081,101	2,081,101
539			$ 3,080,435	$ 2,081,290	$ 37,862,447
540					
541	**Subtotal Plant in Service Before General Plant**		**$ 3,080,435**	**$ 2,081,290**	**$ 37,862,447**
542					
543	General Plant				
544	Land & Land Rights	389	$ -	$ -	$ -
545	Structures & Improvements	390	126,713	37,959	691,045

Test Year Revenue Requirement - Distribution

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Distributior

Line No.		FERC Account	Customer Related Meters	Direct Assignments City-Owned Lighting	Total
A		B	K	L	M
546	Office Furniture & Equipment	391	314,461	94,202	1,714,948
547	Transportation Equipment	392	217,354	65,112	1,185,365
548	Stores Equipment	393	46	14	248
549	Tools, Shop & Garage Equipment	394	35,030	10,494	191,042
550	Laboratory Equipment	395	3,973	1,190	21,668
551	Power Operated Equipment	396	2,366	709	12,904
552	Communications Equipment	397	147,234	44,106	802,956
553	Miscellaneous Equipment	398	959	287	5,227
554	Other Tangible Property	399	-	-	-
555			$ 848,137	$ 254,072	$ 4,625,404
556					
557	**Total Plant Depreciation**		**$ 3,928,572**	**$ 2,335,362**	**$ 42,487,850**
558					
559					
560					
561					
562					
563	**Labor**				
564					
636					
637	**Total Power Production Expense**		**$ -**	**$ -**	**$ -**
638					
659					
660	**Total Transmission Expenses**		**$ -**	**$ -**	**$ -**
661					
662	**Distribution Expenses**				
663	**Operation**				
664	Operations Supervision and Engineering	580	$ 1,650,612	$ 215,835	$ 7,760,072
665	Load Dispatching	581	-	-	1,198,111
666	Station Expenses	582	-	-	47,661
667	Overhead Line Expenses	583	-	-	5,683,357
668	Underground Line Expenses	584	-	-	2,408,599
669	Street Lighting	585	-	300,672	300,672
670	Meter Expenses	586	2,876,854	-	2,876,854
671	Customer Installation Expenses	587	-	-	-
672	Miscellaneous Distribution Expenses	588	116,355	90,722	1,556,809
673	Rents	589	-	-	-
674			$ 4,643,821	$ 607,230	$ 21,832,135
675					
676	**Maintenance**				
677	Maintenance Supervision and Engineering	590	$ 5,279	$ 27,050	$ 142,290
678	Maintenance of Structures	591	-	-	-
679	Maintenance of Station Equipment	592	-	-	1,360,500
680	Maintenance of Overhead Lines	593	-	-	1,009,486
681	Maintenance of Underground Lines	594	-	-	476
682	Maintenance of Line Transformers	595	-	-	8,330
683	Maintenance of Street Lighting and Signal Systems	596	-	745,315	745,315
684	Maintenance of Meters	597	79,995	-	79,995
685	Maintenance of Miscellaneous Distribution Plant	598	77,222	60,210	1,033,220
686			$ 162,497	$ 832,575	$ 4,379,612
687					
688	**Total Distribution Expenses**		**$ 4,806,318**	**$ 1,439,805**	**$ 26,211,747**
689					
710					
711	**Total Customer and Information Expenses**		**$ -**	**$ -**	**$ -**
712					

Test Year Revenue Requirement - Distribution

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Distribution

Line No.			FERC Account	Customer Related Meters	Direct Assignments City-Owned Lighting	Total
A			B	K	L	M
713	**General and Administrative Expenses**					
714		Administrative and General Salaries	920	$ 2,294,891	$ 687,469	$ 12,515,425
715		Office Supplies and Expenses	921	640	192	3,488
716		Administrative Expense Transferred	922	-	-	-
717		Outside Services Employed	923	72	32	651
718		Property Insurance	924	-	-	-
719		Injuries and Damages	925	-	-	-
720		Employee Pension and Benefits	926	-	-	-
721		Regulatory Commission Expense	928	-	-	-
722		General Expenses	930	54,070	16,197	294,875
723		Rents	931	-	-	-
724		Maintenance of General Plant	935	-	-	-
725				$ 2,349,673	$ 703,891	$ 12,814,439
726						
727	**Total Electric Labor**			**$ 7,155,990**	**$ 2,143,696**	**$ 39,026,186**
728						
729						
730						
731	**Allocation Factors**					
732	1	D Load Dispatch		0.0%	0.0%	100.0%
733		Direct Assignment to Load Dispatch within the Distribution Function				1
734						
735	2	Primary		0.0%	0.0%	100.0%
736		Direct Assignment to Primary				1
737						
738	3	Dist General Plnt - Net		18.3%	5.5%	100.0%
739		Net General Plant within Distribution Function		8,458,534	2,533,882	46,129,483
740						
741	4	Transformers		0.0%	0.0%	100.0%
742		Direct Assignment to Transformers				1
743						
744	5	Meters		100.0%	0.0%	100.0%
745		Direct Assignment to Meters		1		1
746						
747	6	Services		0.0%	0.0%	100.0%
748		Direct Assignment to Services				1
749						
750	7	Dist Lighting		0.0%	100.0%	100.0%
751		Direct Assignment to City-Owned Lighting (Street and Signal Lighting)			1	1
752						
753	8	Secondary		0.0%	0.0%	100.0%
754		Direct Assignment to Secondary				1
755						
756	9	580 Op Supervision		21.3%	2.8%	100.0%
757				2,993,209	391,395	14,072,063
758						
759	10	590 Maint Supervision		3.7%	19.0%	100.0%
760				157,217	805,525	4,237,322
761						
762	11	363 Storage		6.5%	5.8%	100.0%
763		Gross Distribution Plant In Service, Excluding FERC 363		87,688,116	77,997,340	1,342,522,521
764						
765	12	Dist Plant - Net		7.5%	5.8%	100.0%
766		Net Distribution Plant in Service		56,755,092	44,252,121	759,372,950
767						
768	13	Dist Labor		18.3%	5.5%	100.0%
769		Total Distribution Labor, Including Direct Assignments		4,806,318	1,439,805	26,211,747

Test Year Revenue Requirement - Distribution

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Distributior

Line No.			FERC Account	Customer Related Meters	Direct Assignments City-Owned Lighting	Total
A			B	K	L	M
770						
771	14	Dist RR		9.9%	5.7%	100.0%
772		Revenue Requirement Associated with Distribution, Including Direct Assigr		17,108,086	9,835,657	172,452,854
773						
774	15	Overhead P&C	WP 34 - Dis	0.0%	0.0%	100.0%
775						2,506
776						
777	16	Underground	WP 34 - Dis	0.0%	0.0%	100.0%
778						4,466
779						
780	17	T Dist Plant - Depr		9.2%	5.5%	100.0%
781		Total Depreciation for Distribution Plant In Service, Including General Plan		3,928,572	2,335,362	42,487,850
782						
783	18	Dist O&M EXAG		11.0%	5.0%	100.0%
784		Total Distribution O&M, Excluding A&G		5,414,209	2,445,451	49,042,519
785						
786	19	Dist Other Rev	WP 15 - Oth	19.7%	1.1%	100.0%
787		Other Revenue Summary		$ 1,845,030	$ 101,466	$ 9,352,089
788		Primary Related Direct Assignment		$ -	$ -	$ 2,915,919
789		Secondary Related Direct Assignment		$ -	$ -	$ 68,697
790		Meter Related Direct Assignment		$ 1,752,839	$ -	$ 1,752,839
791		Services Related Direct Assignment		$ -	$ -	$ 2,986,468
792		Load Dispatch Related Direct Assignment		$ -	$ -	$ 365,094
793		Lighting Related Direct Assignment		$ -	$ 29,585	$ 29,585
794		Remainder Allocated on Net Distribution Plant in Service		$ 92,190	$ 71,881	$ 1,233,487
788						

Test Year Revenue Requirement - Customer

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Customer

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Customer Related: Customer Accounting	Customer Service	Meter Reading	Uncollectibles	Key Accounts	Total
A		B	C	D	E	F	G	H	I	J	K
78											
79	**Total Power Production Expense**			$ -		$ -	$ -	$ -	$ -	$ -	$ -
80											
101											
102	**Total Transmission Expenses**			$ -		$ -	$ -	$ -	$ -	$ -	$ -
103											
129											
130	**Total Distribution Expenses**			$ -		$ -	$ -	$ -	$ -	$ -	$ -
131											
132	**Customer and Information Expenses**										
133											
134	Customer Accounts Expenses										
135	Supervision	901	Functional Unbundling	$ 109,431	Cust Acct Supervision	$ 86,395	$ -	$ 23,035	$ -	$ 1	$ 109,431
136	Meter Reading Expenses	902	Functional Unbundling	14,291,107	FERC 902	-	-	14,290,490	-	617	14,291,107
137	Customer Records and Collection Expenses	903	Functional Unbundling	27,747,774	Cust Accounting	27,747,774	-	-	-	-	27,747,774
138	Uncollectible Accounts	904	Functional Unbundling	4,669,787	Uncollectible DA	-	-	-	4,669,787	-	4,669,787
139	Miscellaneous Customer Accounts Expenses	905	Functional Unbundling	(16,327,537)	Cust Accounting	(16,327,537)	-	-	-	-	(16,327,537)
140				$ 30,490,562		$ 11,506,632	$ -	$ 14,313,525	$ 4,669,787	$ 617	$ 30,490,562
141											
142	Cust. Service & Information Expense										
143	Supervision	907	Functional Unbundling	$ 174,286	Cust Serv Supervision	$ -	$ 158,884	$ -	$ -	$ 15,402	$ 174,286
144	Customer Assistance Expenses	908	Functional Unbundling	240,646	Cust Service	-	240,646	-	-	-	240,646
145	Informational & Instructional Advertising Expenses	909	Functional Unbundling	88,576	Cust Service	-	88,576	-	-	-	88,576
146	Misc Customer Service & Informational Expenses	910	Functional Unbundling	341,418	Cust Service	-	341,418	-	-	-	341,418
147	Supervision	911	Functional Unbundling	10,140,552	FERC 911	-	10,122,790	-	-	17,762	10,140,552
148	Demonstrating & Selling Expense	912	Functional Unbundling	3,363,747	FERC 912	-	2,006,140	-	-	1,357,607	3,363,747
149	Advertising Expense	913	Functional Unbundling	489,534	Cust Service	-	489,534	-	-	-	489,534
150	Miscellaneous Sales Expense	916	Functional Unbundling	326,690	FERC 916	-	325,020	-	-	1,669	326,690
151				$ 15,165,448		$ -	$ 13,773,008	$ -	$ -	$ 1,392,440	$ 15,165,448
152											
153	**Total Customer and Information Expenses**			**$ 45,656,010**		**$ 11,506,632**	**$ 13,773,008**	**$ 14,313,525**	**$ 4,669,787**	**$ 1,393,058**	**$ 45,656,010**
154											
155	**General and Administrative Expenses**										
156	Administrative and General Salaries	920	Functional Unbundling	$ 10,760,137	Cust Labor	$ 4,860,755	$ 4,196,543	$ 1,295,967	$ -	$ 406,873	$ 10,760,137
157	Office Supplies and Expenses	921	Functional Unbundling	7,431,014	Cust Labor	3,356,866	2,898,157	895,002	-	280,989	7,431,014
158	Administrative Expense Transferred	922	Functional Unbundling	465,371	Cust Labor	210,225	181,498	56,050	-	17,597	465,371
159	Outside Services Employed	923	Functional Unbundling	1,117,091	Cust O&M EXAG	281,539	336,992	350,217	114,258	34,085	1,117,091
160	Property Insurance	924	Functional Unbundling	7,004	Cust General Plnt - Net	5,973	733	226	-	71	7,004
161	Injuries and Damages	925	Functional Unbundling	911,067	Cust Labor	411,563	355,324	109,730	-	34,450	911,067
162	Employee Pension and Benefits	926	Functional Unbundling	219,500	Cust Labor	99,156	85,607	26,437	-	8,300	219,500
163	Regulatory Commission Expense	928	Functional Unbundling	-	Cust RR	-	-	-	-	-	-
164	General Expenses	930	Functional Unbundling	7,296,562	Cust Labor	3,296,129	2,845,719	878,808	-	275,905	7,296,562
165	Rents	931	Functional Unbundling	872,138	Cust Labor	393,977	340,141	105,042	-	32,978	872,138
166	Maintenance of General Plant	935	Functional Unbundling	21,316	Cust General Plnt - Net	18,179	2,231	689	-	216	21,316
167				$ 29,101,199		$ 12,934,363	$ 11,242,945	$ 3,718,168	$ 114,258	$ 1,091,464	$ 29,101,199
168											
169	**Total Operations & Maintenance Expenses**			**$ 74,757,209**		**$ 24,440,995**	**$ 25,015,953**	**$ 18,031,693**	**$ 4,784,046**	**$ 2,484,522**	**$ 74,757,209**
170											
171	**Depreciation & Amortization of CIAC**										
172	Depreciation Expense	403	Functional Unbundling	$ 5,820,131	Cust General Plnt - Depr	$ 4,220,163	$ 1,138,141	$ 351,478	$ -	$ 110,348	$ 5,820,131
173	Amortization of CIAC		Functional Unbundling	-	Cust General Plnt - Depr	-	-	-	-	-	-
174				**$ 5,820,131**		**$ 4,220,163**	**$ 1,138,141**	**$ 351,478**	**$ -**	**$ 110,348**	**$ 5,820,131**
175											
176	**Debt Service**		Functional Unbundling	**$ 65,051**	Cust General Plnt - Net	**$ 55,479**	**$ 6,809**	**$ 2,103**	**$ -**	**$ 660**	**$ 65,051**
177											
178	**General Fund Transfer**	421.5	Functional Unbundling	**$ 8,705,594**	Cust RR	**$ 3,028,824**	**$ 3,022,380**	**$ 1,898,039**	**$ 477,537**	**$ 278,813**	**$ 8,705,594**

Test Year Revenue Requirement - Customer
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Customer

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Customer Related: Customer Accounting	Customer Service	Meter Reading	Uncollectibles	Key Accounts	Total
A		B	C	D	E	F	G	H	I	J	K
179											
180	**Margin**		Functional Unbundling	$ 10,425,331	Cust General Plnt - Depr	$ 7,559,384	$ 2,038,700	$ 629,587	$ -	$ 197,661	$ 10,425,331
181											
182	**Sub-Total Revenue Requirement**			**$ 99,773,315**		**$ 39,304,845**	**$ 31,221,983**	**$ 20,912,900**	**$ 5,261,583**	**$ 3,072,004**	**$ 99,773,315**
183											
184	**Other Expenses**										
185	Misc Service Revenue	451	Functional Unbundling	$ -	Cust RR	$ -	$ -	$ -	$ -	$ -	$ -
186	Donations	426	Functional Unbundling	-	Cust RR	-	-	-	-	-	-
187	Taxes Other Than Income	408	Functional Unbundling	2,242	Cust RR	780	778	489	123	72	2,242
188	Expenses - Non-utility operations	417	Functional Unbundling	2,079,086	Cust Service	-	2,079,086	-	-	-	2,079,086
189	Franchise Fees		Functional Unbundling	-	Cust RR	-	-	-	-	-	-
190				**$ 2,081,328**		**$ 780**	**$ 2,079,864**	**$ 489**	**$ 123**	**$ 72**	**$ 2,081,328**
191											
192	**Other (Non-Rate) Revenue**										
193	Miscellaneous Nonoperating Income	421	Functional Unbundling	$ -	Cust RR	$ -	$ -	$ -	$ -	$ -	$ -
194	Other Revenue		Functional Unbundling	5,932,775	Cust Accounting	5,932,775	-	-	-	-	5,932,775
195	Off-System Sales		Functional Unbundling	-	Cust RR	-	-	-	-	-	-
196				**$ 5,932,775**		**$ 5,932,775**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5,932,775**
197											
198	**Total Revenue Requirement**			**$ 95,921,868**		**$ 33,372,851**	**$ 33,301,847**	**$ 20,913,388**	**$ 5,261,706**	**$ 3,072,075**	**$ 95,921,868**
199											
200	**System Retail Sales (MWH)**		Functional Unbundling	11,813,939							
201	Average Rate ($/MWh)			$ 8.12							
202											
203											
204											
205	**Gross Plant In Service**										
273											
274	**Subtotal Plant in Service Before General Plant**			**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
275											
276	General Plant										
277	Land & Land Rights	389	WP 2	$ 1,802,385	Cust Labor	$ 814,205	$ 702,945	$ 217,082	$ -	$ 68,154	$ 1,802,385
278	Structures & Improvements	390	WP 2	4,767,047	Cust Labor	2,153,453	1,859,188	574,150	-	180,256	4,767,047
279	Office Furniture & Equipment	391	WP 2	61,176,303	391 Furniture - G	46,727,536	10,278,172	3,174,081	-	996,513	61,176,303
280	Transportation Equipment	392	WP 2	-	Cust Labor	-	-	-	-	-	-
281	Stores Equipment	393	WP 2	-	Cust Labor	-	-	-	-	-	-
282	Tools, Shop & Garage Equipment	394	WP 2	-	Cust Labor	-	-	-	-	-	-
283	Laboratory Equipment	395	WP 2	-	Cust Labor	-	-	-	-	-	-
284	Power Operated Equipment	396	WP 2	-	Cust Labor	-	-	-	-	-	-
285	Communications Equipment	397	WP 2	10,623,915	Cust Labor	4,799,219	4,143,415	1,279,560	-	401,722	10,623,915
286	Miscellaneous Equipment	398	WP 2	-	Cust Labor	-	-	-	-	-	-
287	Other Tangible Property	399	WP 2	-	Cust Labor	-	-	-	-	-	-
288				$ 78,369,650		$ 54,494,412	$ 16,983,720	$ 5,244,873	$ -	$ 1,646,645	$ 78,369,650
289											
290	**Total Plant in Service - Gross**			**$ 78,369,650**		**$ 54,494,412**	**$ 16,983,720**	**$ 5,244,873**	**$ -**	**$ 1,646,645**	**$ 78,369,650**
291											
292											
293											
294	**Accumulated Depreciation**										
362											
363	**Subtotal Plant in Service Before General Plant**			**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
364											
365	General Plant										
366	Land & Land Rights	389	WP 2	$ -	Cust Labor	$ -	$ -	$ -	$ -	$ -	$ -
367	Structures & Improvements	390	WP 2	2,472,371	Cust Labor	1,116,862	964,245	297,776	-	93,488	2,472,371
368	Office Furniture & Equipment	391	WP 2	24,183,470	391 Furniture - AD	12,515,568	8,299,995	2,563,185	-	804,721	24,183,470

Test Year Revenue Requirement - Customer
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Customer

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Customer Related: Customer Accounting	Customer Service	Meter Reading	Uncollectibles	Key Accounts	Total
A		B	C	D	E	F	G	H	I	J	K
369	Transportation Equipment	392	WP 2	-	Cust Labor	-	-	-	-	-	-
370	Stores Equipment	393	WP 2	-	Cust Labor	-	-	-	-	-	-
371	Tools, Shop & Garage Equipment	394	WP 2	-	Cust Labor	-	-	-	-	-	-
372	Laboratory Equipment	395	WP 2	-	Cust Labor	-	-	-	-	-	-
373	Power Operated Equipment	396	WP 2	-	Cust Labor	-	-	-	-	-	-
374	Communications Equipment	397	WP 2	8,083,433	Cust Labor	3,651,588	3,152,606	973,580	-	305,659	8,083,433
375	Miscellaneous Equipment	398	WP 2	-	Cust Labor	-	-	-	-	-	-
376	Other Tangible Property	399	WP 2	-	Cust Labor	-	-	-	-	-	-
377				$ 34,739,274		$ 17,284,018	$ 12,416,846	$ 3,834,542	$ -	$ 1,203,867	$ 34,739,274
378											
379	**Total Plant in Service - Accumulated Depreciation**			**$ 34,739,274**		**$ 17,284,018**	**$ 12,416,846**	**$ 3,834,542**	**$ -**	**$ 1,203,867**	**$ 34,739,274**
380											
381											
382											
383	**Net Plant In Service**										
451											
452	**Subtotal Plant in Service Before General Plant**			**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
453											
454	General Plant										
455	Land & Land Rights	389	WP 2	$ 1,802,385	Cust Labor	$ 814,205	$ 702,945	$ 217,082	$ -	$ 68,154	$ 1,802,385
456	Structures & Improvements	390	WP 2	2,294,676	Cust Labor	1,036,591	894,943	276,374	-	86,769	2,294,676
457	Office Furniture & Equipment	391	WP 2	36,992,834	391 Furniture - N	34,211,968	1,978,177	610,896	-	191,793	36,992,834
458	Transportation Equipment	392	WP 2	-	Cust Labor	-	-	-	-	-	-
459	Stores Equipment	393	WP 2	-	Cust Labor	-	-	-	-	-	-
460	Tools, Shop & Garage Equipment	394	WP 2	-	Cust Labor	-	-	-	-	-	-
461	Laboratory Equipment	395	WP 2	-	Cust Labor	-	-	-	-	-	-
462	Power Operated Equipment	396	WP 2	-	Cust Labor	-	-	-	-	-	-
463	Communications Equipment	397	WP 2	2,540,482	Cust Labor	1,147,630	990,809	305,979	-	96,063	2,540,482
464	Miscellaneous Equipment	398	WP 2	-	Cust Labor	-	-	-	-	-	-
465	Other Tangible Property	399	WP 2	-	Cust Labor	-	-	-	-	-	-
466				$ 43,630,377		$ 37,210,394	$ 4,566,873	$ 1,410,331	$ -	$ 442,778	$ 43,630,377
467											
468	**Total Plant in Service - Net**			**$ 43,630,377**		**$ 37,210,394**	**$ 4,566,873**	**$ 1,410,331**	**$ -**	**$ 442,778**	**$ 43,630,377**
469											
470											
471											
472	**Depreciation Expense**										
540											
541	**Subtotal Plant in Service Before General Plant**			**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
542											
543	General Plant										
544	Land & Land Rights	389	WP 2	$ -	Cust Labor	$ -	$ -	$ -	$ -	$ -	$ -
545	Structures & Improvements	390	WP 2	130,610	Cust Labor	59,001	50,939	15,731	-	4,939	130,610
546	Office Furniture & Equipment	391	WP 2	5,026,022	391 Furniture - Depr	3,861,435	828,433	255,835	-	80,320	5,026,022
547	Transportation Equipment	392	WP 2	-	Cust Labor	-	-	-	-	-	-
548	Stores Equipment	393	WP 2	-	Cust Labor	-	-	-	-	-	-
549	Tools, Shop & Garage Equipment	394	WP 2	-	Cust Labor	-	-	-	-	-	-
550	Laboratory Equipment	395	WP 2	-	Cust Labor	-	-	-	-	-	-
551	Power Operated Equipment	396	WP 2	-	Cust Labor	-	-	-	-	-	-
552	Communications Equipment	397	WP 2	663,498	Cust Labor	299,727	258,770	79,913	-	25,089	663,498
553	Miscellaneous Equipment	398	WP 2	-	Cust Labor	-	-	-	-	-	-
554	Other Tangible Property	399	WP 2	-	Cust Labor	-	-	-	-	-	-
555				$ 5,820,130		$ 4,220,163	$ 1,138,141	$ 351,478	$ -	$ 110,348	$ 5,820,130
556											
557	**Total Plant Depreciation**			**$ 5,820,130**		**$ 4,220,163**	**$ 1,138,141**	**$ 351,478**	**$ -**	**$ 110,348**	**$ 5,820,130**
558											

Test Year Revenue Requirement - Customer
Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Customer

Line No.		FERC Account	Source Reference	Test Year	Allocation Basis	Customer Related: Customer Accounting	Customer Service	Meter Reading	Uncollectibles	Key Accounts	Total
A		B	C	D	E	F	G	H	I	J	K
559											
560											
561											
562											
563	**Labor**										
564											
636											
637	**Total Power Production Expense**			$ -		$ -	$ -	$ -	$ -	$ -	$ -
638											
659											
660	**Total Transmission Expenses**			$ -		$ -	$ -	$ -	$ -	$ -	$ -
661											
687											
688	**Total Distribution Expenses**			$ -		$ -	$ -	$ -	$ -	$ -	$ -
689											
690	**Customer and Information Expenses**										
691											
692	Customer Accounts Expenses										
693	Supervision	901	WP 3.1	$ 230,365	Cust Acct Supervision	$ 181,872	$ -	$ 48,490	$ -	$ 2	$ 230,365
694	Meter Reading Expenses	902	WP 3.1	3,938,836	FERC 902	-	-	3,938,666	-	170	3,938,836
695	Customer Records and Collection Expenses	903	WP 3.1	14,772,673	Cust Accounting	14,772,673	-	-	-	-	14,772,673
696	Uncollectible Accounts	904	WP 3.1	-	Uncollectible DA	-	-	-	-	-	-
697	Miscellaneous Customer Accounts Expenses	905	WP 3.1	-	Cust Accounting	-	-	-	-	-	-
698				$ 18,941,874		$ 14,954,546	$ -	$ 3,987,156	$ -	$ 172	$ 18,941,874
699											
700	Cust. Service & Information Expense										
701	Supervision	907	WP 3.1	$ 1,896,089	Cust Serv Supervision	$ -	$ 1,728,524	$ -	$ -	$ 167,565	$ 1,896,089
702	Customer Assistance Expenses	908	WP 3.1	3,988,870	Cust Service	-	3,988,870	-	-	-	3,988,870
703	Informational & Instructional Advertising Expenses	909	WP 3.1	7,638	Cust Service	-	7,638	-	-	-	7,638
704	Misc Customer Service & Informational Expenses	910	WP 3.1	569,986	Cust Service	-	569,986	-	-	-	569,986
705	Supervision	911	WP 3.1	4,704,773	FERC 911	-	4,696,533	-	-	8,241	4,704,773
706	Demonstrating & Selling Expense	912	WP 3.1	2,665,522	FERC 912	-	1,589,718	-	-	1,075,803	2,665,522
707	Advertising Expense	913	WP 3.1	329,768	Cust Service	-	329,768	-	-	-	329,768
708	Miscellaneous Sales Expense	916	WP 3.1	-	FERC 916	-	-	-	-	-	-
709				$ 14,162,645		$ -	$ 12,911,036	$ -	$ -	$ 1,251,609	$ 14,162,645
710											
711	**Total Customer and Information Expenses**			**$ 33,104,519**		**$ 14,954,546**	**$ 12,911,036**	**$ 3,987,156**	**$ -**	**$ 1,251,781**	**$ 33,104,519**
712											
713	**General and Administrative Expenses**										
714	Administrative and General Salaries	920	WP 3.1	$ 15,806,544	Cust Labor	$ 7,140,405	$ 6,164,683	$ 1,903,763	$ -	$ 597,693	$ 15,806,544
715	Office Supplies and Expenses	921	WP 3.1	4,405	Cust Labor	1,990	1,718	531	-	167	4,405
716	Administrative Expense Transferred	922	WP 3.1	-	Cust Labor	-	-	-	-	-	-
717	Outside Services Employed	923	WP 3.1	606	Cust O&M EXAG	153	183	190	62	18	606
718	Property Insurance	924	WP 3.1	-	Cust General Plnt - Net	-	-	-	-	-	-
719	Injuries and Damages	925	WP 3.1	-	Cust Labor	-	-	-	-	-	-
720	Employee Pension and Benefits	926	WP 3.1	-	Cust Labor	-	-	-	-	-	-
721	Regulatory Commission Expense	928	WP 3.1	-	Cust RR	-	-	-	-	-	-
722	General Expenses	930	WP 3.1	372,417	Cust Labor	168,235	145,246	44,854	-	14,082	372,417
723	Rents	931	WP 3.1	-	Cust Labor	-	-	-	-	-	-
724	Maintenance of General Plant	935	WP 3.1	-	Cust General Plnt - Net	-	-	-	-	-	-
725				$ 16,183,972		$ 7,310,783	$ 6,311,829	$ 1,949,338	$ 62	$ 611,960	$ 16,183,972
726											
727	**Total Electric Labor**			**$ 49,288,491**		**$ 22,265,328**	**$ 19,222,866**	**$ 5,936,494**	**$ 62**	**$ 1,863,741**	**$ 49,288,491**
728											
729											
730											

Test Year Revenue Requirement - Customer

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Customer

Line No.			FERC Account	Source Reference	Test Year	Allocation Basis	Customer Related: Customer Accounting	Customer Service	Meter Reading	Uncollectibles	Key Accounts	Total
A			B	C	D	E	F	G	H	I	J	K
731	**Allocation Factors**											
732	1	Cust Accounting					100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
733		Direct Assignment to Customer Accounting					1					1
734												
735	2	Cust Service					0.0%	100.0%	0.0%	0.0%	0.0%	100.0%
736		Direct Assignment to Customer Service						1				1
737												
738	3	Cust Labor					45.2%	39.0%	12.0%	0.0%	3.8%	100.0%
739		Total Customer Labor					14,954,546	12,911,036	3,987,156	-	1,251,781	33,104,519
740												
741	4	391 Furniture - N		WP 2 - Plant & WP 2.3 - Plant			92.5%	5.3%	1.7%	0.0%	0.5%	100.0%
742		Net FERC 391 Based on New CC&B to Cust Accounting and Remainder to Cust Labor			$ 36,992,834		$ 34,211,968	$ 1,978,177	$ 610,896	$ -	$ 191,793	36,992,834
743					$ 31,920,693	Cust Accounting	$ 31,920,693	$ -	$ -	$ -	$ -	$ 31,920,693
744					$ 5,072,140	Cust Labor	$ 2,291,275	$ 1,978,177	$ 610,896	$ -	$ 191,793	$ 5,072,140
745												
746	5	391 Furniture - G		WP 2 - Plant & WP 2.3 - Plant			76.4%	16.8%	5.2%	0.0%	1.6%	100.0%
747		Gross FERC 391 Based on New CC&B to Cust Accounting and Remainder to Cust Labor			$ 61,176,303		$ 46,727,536	$ 10,278,172	$ 3,174,081	$ -	$ 996,513	61,176,303
748					$ 34,822,575	Cust Accounting	$ 34,822,575	$ -	$ -	$ -	$ -	$ 34,822,575
749					$ 26,353,729	Cust Labor	$ 11,904,962	$ 10,278,172	$ 3,174,081	$ -	$ 996,513	$ 26,353,729
750												
751	6	391 Furniture - AD		WP 2 - Plant & WP 2.3 - Plant			51.8%	34.3%	10.6%	0.0%	3.3%	100.0%
752		Accumulated Depreciation FERC 391 Based on New CC&B to Cust Accounting and Remainder to Cus			$ 24,183,470		$ 12,515,568	$ 8,299,995	$ 2,563,185	$ -	$ 804,721	24,183,470
753					$ 2,901,881	Cust Accounting	$ 2,901,881	$ -	$ -	$ -	$ -	$ 2,901,881
754					$ 21,281,588	Cust Labor	$ 9,613,687	$ 8,299,995	$ 2,563,185	$ -	$ 804,721	$ 21,281,588
755												
756	7	Cust O&M EXAG					25.2%	30.2%	31.4%	10.2%	3.1%	100.0%
757		Total Customer O&M, Excluding A&G and Regulatory and Community Benefit Adjustment Clauses					11,506,632	13,773,008	14,313,525	4,669,787	1,393,058	45,656,010
758												
759	8	Cust General Plnt - Net					85.3%	10.5%	3.2%	0.0%	1.0%	100.0%
760		Net General Plant within Customer Function					37,210,394	4,566,873	1,410,331	-	442,778	43,630,377
761												
762	9	Cust RR					34.8%	34.7%	21.8%	5.5%	3.2%	100.0%
763		Revenue Requirement Associated with Customer Function, Excluding Regulatory and Community Benefit Adjustment Clauses					33,372,851	33,301,847	20,913,388	5,261,706	3,072,075	95,921,868
764												
765	10	Cust General Plnt - Depr					72.5%	19.6%	6.0%	0.0%	1.9%	100.0%
766		Depreciation of General Plant within Customer Function					4,220,163	1,138,141	351,478	-	110,348	5,820,130
767												
768	11	Cust Acct Supervision					78.9%	0.0%	21.0%	0.0%	0.0%	100.0%
769		Sub-functionalization of FERC 901 Based on Allocation of Labor Costs in FERC 902 - FERC 905					14,772,673	-	3,938,666	-	170	18,711,509
770												
771	12	Meter Reading					0.0%	0.0%	100.0%	0.0%	0.0%	100.0%
772		Direct Assignment to Meter Reading							1			1
773												
774	13	391 Furniture - Depr		WP 2 - Plant & WP 2.3 - Plant			76.8%	16.5%	5.1%	0.0%	1.6%	100.0%
775		Depreciation FERC 391 Based on New CC&B to Cust Accounting and Remainder to Cust Labor			$ 5,026,022		$ 3,861,435	$ 828,433	$ 255,835	$ -	$ 80,320	5,026,022
776					$ 2,901,881	Cust Accounting	$ 2,901,881	$ -	$ -	$ -	$ -	$ 2,901,881
777					$ 2,124,141	Cust Labor	$ 959,554	$ 828,433	$ 255,835	$ -	$ 80,320	$ 2,124,141
778												
779	14	Uncollectible DA					0.0%	0.0%	0.0%	100.0%	0.0%	100.0%
780		Direct Assignment to Uncollectible								1		1
781												
782	15	Key Accounts DA					0.0%	0.0%	0.0%	0.0%	100.0%	100.0%
783		Direct Assignment to Key Accounts									1	1
784												
785	16	Cust Serv Supervision					0.0%	91.2%	0.0%	0.0%	8.8%	100.0%
786		Sub-functionalization of FERC 907 Based on Allocation of Labor Costs in FERC 908 - FERC 910					-	11,182,512	-	-	1,084,044	12,266,556
787												

Test Year Revenue Requirement - Customer

Purpose: Sub-Functionalize the Test Year Revenue Requirement Related to Customer

Line No.			FERC Account	Source Reference	Test Year	Allocation Basis	Customer Related: Customer Accounting	Customer Service	Meter Reading	Uncollectibles	Key Accounts	Total
A			B	C	D	E	F	G	H	I	J	K
788	17	FERC 902	WP 36 - Cust Bus				0.0%	0.0%	100.0%	0.0%	0.0%	100.0%
789		FERC 902 Based on Direct Allocation in WP 36 and Remainder to Customer Service			$ 14,291,107		$ -	$ -	$ 14,290,490	$ -	$ 617	14,291,107
790					$ 617	Key Accounts DA	$ -	$ -	$ -	$ -	$ 617	$ 617
791					$ 14,290,490	Meter Reading	$ -	$ -	$ 14,290,490	$ -	$ -	$ 14,290,490
792												
793	18	FERC 916	WP 36 - Cust Bus				0.0%	99.5%	0.0%	0.0%	0.5%	100.0%
794		FERC 916 Based on Direct Allocation in WP 36 and Remainder to Customer Service			$ 326,690		$ -	$ 325,020	$ -	$ -	$ 1,669	326,690
795		WP 36 - Cust Bus Direct to Key Accounts			$ 1,669	Key Accounts DA	$ -	$ -	$ -	$ -	$ 1,669	$ 1,669
796		Remaining FERC 916 Allocated to Customer Service			$ 325,020	Cust Service	$ -	$ 325,020	$ -	$ -	$ -	$ 325,020
797												
798	19	FERC 911	WP 36 - Cust Bus				0.0%	99.8%	0.0%	0.0%	0.2%	100.0%
799		FERC 911 Based on Direct Allocation in WP 36 and Remainder to Customer Service			$ 10,140,552		$ -	$ 10,122,790	$ -	$ -	$ 17,762	10,140,552
800		WP 36 - Cust Bus Direct to Key Accounts			$ 17,762	Key Accounts DA	$ -	$ -	$ -	$ -	$ 17,762	$ 17,762
801		Remaining FERC 911 Allocated to Customer Service			$ 10,122,790	Cust Service	$ -	$ 10,122,790	$ -	$ -	$ -	$ 10,122,790
802												
803	20	FERC 912	WP 36 - Cust Bus				0.0%	59.6%	0.0%	0.0%	40.4%	100.0%
804		FERC 912 Based on Direct Allocation in WP 36 and Remainder to Customer Service			$ 3,363,747		$ -	$ 2,006,140	$ -	$ -	$ 1,357,607	3,363,747
805		WP 36 - Cust Bus Direct to Key Accounts			$ 1,357,607	Key Accounts DA	$ -	$ -	$ -	$ -	$ 1,357,607	$ 1,357,607
806		Remaining FERC 912 Allocated to Customer Service			$ 2,006,140	Cust Service	$ -	$ 2,006,140	$ -	$ -	$ -	$ 2,006,140

Test Year Cost of Service

Purpose: Identify the Cost of Service by Customer Class

Line No.		Rate Design	TOU Period (On-Peak = June - Sept)	Test Year	Allocation Basis	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW
A		B	C	D	E	F	G	H	I	J	K
1	**Production**										
2	**Demand Related**										
3	Base Load - Nuclear	Demand	Annual	$ 174,998,382	Ave & Excess	$ 72,062,682	$ 6,093,284	$ 15,816,725	$ 57,202,697	$ 4,592,592	$ 7,410,131
4	Base Load - Coal	Demand	Annual	77,153,403	Ave & Excess	31,771,043	2,686,411	6,973,288	25,219,563	2,024,785	3,266,983
5	Intermediate - Gas	Demand	Annual	58,658,794	Ave & Excess	24,155,138	2,042,446	5,301,706	19,174,127	1,539,419	2,483,848
6	Peak - Gas	Demand	On-Peak	12,952,332	Ave & Excess	5,333,648	450,988	1,170,659	4,233,801	339,916	548,453
7	Renewable - Solar	Demand	Annual	7,799,190	Ave & Excess	3,211,633	271,561	704,907	2,549,365	204,679	330,249
8				$ 331,562,101		$ 136,534,144	$ 11,544,690	$ 29,967,286	$ 108,379,553	$ 8,701,391	$ 14,039,664
9											
10	**Energy Related**										
11	Base Load - Nuclear - Fuel	Energy	Annual	22,085,109	NEFL Net GC	7,313,534	709,568	1,841,820	7,660,838	744,897	1,444,395
12	Base Load - Coal - Fuel	Energy	Annual	125,056,934	NEFL Net GC	41,412,887	4,017,927	10,429,303	43,379,498	4,217,982	8,178,885
13	Intermediate - Gas - Fuel	Energy	Annual	153,295,739	NEFL Net GC	50,764,231	4,925,205	12,784,319	53,174,918	5,170,434	10,025,739
14	Peak - Gas - Fuel	Energy	On-Peak	11,546,911	NEFL Net GC - S	4,425,673	343,905	917,181	3,765,398	368,665	665,897
15	Economy - Purch Pwr	Energy	Annual	26,351,013	NEFL Net GC	8,726,198	846,626	2,197,581	9,140,586	888,780	1,723,390
16	Renewable - Wind	Energy	Annual	67,321,905	NEFL Net GC	22,293,802	2,162,971	5,614,407	23,352,487	2,270,666	4,402,939
17	Renewable - Solar	Energy	Annual	13,101,348	NEFL Net GC	4,338,541	420,930	1,092,606	4,544,569	441,889	856,845
18	Renewable - LF Methane	Energy	Annual	3,792,761	NEFL Net GC	1,255,981	121,857	316,303	1,315,625	127,924	248,051
19				$ 422,551,719		$ 140,530,848	$ 13,548,989	$ 35,193,520	$ 146,333,920	$ 14,231,238	$ 27,546,142
20											
21	**Direct Assignments**										
22	Regulatory - Adj Clause	Demand	Annual	$ 9,839,798	NEFL Net GC	$ 3,258,472	$ 316,141	$ 820,604	$ 3,413,209	$ 331,882	$ 643,536
23	Community Benefit - Adj Clause	Demand	Annual	27,720,129	Rev Req	11,613,049	1,122,747	2,282,952	8,515,580	705,723	1,250,052
24	Green Choice	Energy	Annual	10,057,082	GC $ Sold	2,384,764	375,868	1,092,030	5,908,653	294,821	-
25				$ 47,617,009		$ 17,256,285	$ 1,814,756	$ 4,195,587	$ 17,837,442	$ 1,332,426	$ 1,893,587
26											
27	**Total Production**			**$ 801,730,829**		**$ 294,321,277**	**$ 26,908,435**	**$ 69,356,393**	**$ 272,550,915**	**$ 24,265,055**	**$ 43,479,393**
28											
29											
30	**Transmission**										
31	**Demand Related**										
32	Transmission - By Others	Demand	On-Peak	65,915,251	4CP-ERCOT Peak	24,909,876	2,376,967	6,488,552	23,271,767	1,804,147	2,864,866
33				$ 65,915,251		$ 24,909,876	$ 2,376,967	$ 6,488,552	$ 23,271,767	$ 1,804,147	$ 2,864,866
34											
35	**Total Transmission**			**$ 65,915,251**		**$ 24,909,876**	**$ 2,376,967**	**$ 6,488,552**	**$ 23,271,767**	**$ 1,804,147**	**$ 2,864,866**
36											
37											

Test Year Cost of Service

Purpose: Identify the Cost of Service by Customer Class

Line No.		Rate Design	TOU Period (On-Peak = June - Sept)	Test Year	Allocation Basis	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW
A		B	C	D	E	F	G	H	I	J	K
38	**Distribution**										
39	**Demand Related**										
40	Primary - Subs, P&C	Demand	Annual	$ 88,666,341	12NCP Primary	$ 34,420,007	$ 3,644,840	$ 8,283,350	$ 30,177,170	$ 2,402,182	$ 4,168,452
41	Secondary - P&C	Demand	Annual	37,442,772	12NCP Secondary	16,698,666	1,768,273	4,018,619	14,640,278	-	-
42	Transformers	Demand	Annual	15,670,208	SMD Excl Primary & Trans	9,501,052	484,229	1,257,504	4,346,478	-	-
43	Services	Demand	Annual	(1,189,256)	SMD Excl Primary & Trans	(721,062)	(36,750)	(95,436)	(329,866)	-	-
44	Load Dispatch	Demand	Annual	4,919,046	12NCP Primary	1,909,559	202,209	459,545	1,674,174	133,269	231,258
45				$ 145,509,111		$ 61,808,222	$ 6,062,801	$ 13,923,583	$ 50,508,233	$ 2,535,450	$ 4,399,710
46											
47	**Customer Related**										
48	Meters	Customer	Annual	$ 17,108,086	Weighted Cust - Meters	$ 12,294,881	$ 3,122,725	$ 1,010,968	$ 526,713	$ 87,361	$ 17,130
49				$ 17,108,086		$ 12,294,881	$ 3,122,725	$ 1,010,968	$ 526,713	$ 87,361	$ 17,130
50											
51	**Direct Assignments**										
52	City-Owned - Lighting	Lighting	Annual	$ 9,835,657	City-Owned Lighting	$ -	$ -	$ -	$ -	$ -	$ -
53				$ 9,835,657		$ -	$ -	$ -	$ -	$ -	$ -
54											
55	**Total Distribution**			**$ 172,452,854**		**$ 74,103,103**	**$ 9,185,526**	**$ 14,934,551**	**$ 51,034,946**	**$ 2,622,811**	**$ 4,416,839**
56											
57											
58	**Customer**										
59	**Customer Related**										
60	Customer - Accounting	Customer	Annual	$ 33,372,851	No. Cust Mo.	$ 29,651,461	$ 2,603,051	$ 842,726	$ 261,427	$ 8,297	$ 1,627
61	Customer - Service	Customer	Annual	33,301,847	No. Cust Mo.	29,588,375	2,597,513	840,933	260,871	8,279	1,623
62	Meter - Reading	Customer	Annual	20,913,388	No. Cust Mo. - Metered	18,581,574	1,631,244	528,108	163,828	5,199	1,020
63	Uncollectibles	Customer	Annual	5,261,706	Uncollectible	4,752,009	405,470	104,227	-	-	-
64	Key - Accounts	Customer	Annual	3,072,075	Key Acct	16,000	304,007	464,011	1,440,035	208,005	464,011
65				$ 95,921,868		$ 82,589,419	$ 7,541,285	$ 2,780,004	$ 2,126,162	$ 229,781	$ 468,281
66											
67	**Total Customer**			**$ 95,921,868**		**$ 82,589,419**	**$ 7,541,285**	**$ 2,780,004**	**$ 2,126,162**	**$ 229,781**	**$ 468,281**
68											
69											
70	**Total Cost of Service**			**$ 1,136,020,803**		**$ 475,923,675**	**$ 46,012,213**	**$ 93,559,500**	**$ 348,983,791**	**$ 28,921,794**	**$ 51,229,379**
71											
72	**Adjustment to Redistribute Service Area Street Lighting**										
73	Street Lighting - Service Area Cost	Adder	Annual	$ (10,434,438)	COA Street Lights	$ -	$ -	$ -	$ -	$ -	$ -
74	Street Lighting - Redistributed	Adder	Annual	10,434,438	Rev Req Excl COA Lights	4,411,919	426,544	867,318	3,235,158	268,112	474,908
75				$ -		$ 4,411,919	$ 426,544	$ 867,318	$ 3,235,158	$ 268,112	$ 474,908
76											
77	**Adjusted Total Cost of Service**			**$ 1,136,020,803**		**$ 480,335,595**	**$ 46,438,756**	**$ 94,426,817**	**$ 352,218,949**	**$ 29,189,906**	**$ 51,704,287**
78											
79											

Test Year Cost of Service

Purpose: Identify the Cost of Service by Customer Class

Line No.		Rate Design (On-Peak = June - Sept)	TOU Period	Test Year	Allocation Basis	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW
A		B	C	D	E	F	G	H	I	J	K
80											
81	**Revenue Adequacy Check - FY 2009 Rate Structure with Test Year FAC**										
82	**Base Rate Revenue**			**$ 604,256,828**		**$ 241,473,520**	**$ 23,486,270**	**$ 57,450,061**	**$ 208,467,594**	**$ 16,898,756**	**$ 21,518,692**
83											
84	**Revenue from Adjustment Clauses**										
85	Recoverable Fuel			$ 390,897,575	NEFL Net GC	$ 129,446,618	$ 12,559,063	$ 32,599,467	$ 135,593,765	$ 13,184,386	$ 25,565,206
86	Green Choice			10,057,082	GC $ Sold	2,384,764	375,868	1,092,030	5,908,653	294,821	-
87	Remove Service Area Street Lighting Fuel Cost			(1,077,588)	COA Street Lights	-	-	-	-	-	-
88				**$ 399,877,069**		**$ 131,831,383**	**$ 12,934,931**	**$ 33,691,497**	**$ 141,502,418**	**$ 13,479,208**	**$ 25,565,206**
89											
90	**Total Rate Revenue**			**$ 1,004,133,897**		**$ 373,304,903**	**$ 36,421,201**	**$ 91,141,558**	**$ 349,970,012**	**$ 30,377,964**	**$ 47,083,898**
91											
92											
93	**Over/(Short)**			**$ (131,886,905)**		**$ (107,030,692)**	**$ (10,017,555)**	**$ (3,285,259)**	**$ (2,248,936)**	**$ 1,188,058**	**$ (4,620,389)**
94											
95	*Required Increase / (Decrease) in Rate Revenue*			*13.1%*		*28.7%*	*27.5%*	*3.6%*	*0.6%*	*-3.9%*	*9.8%*
96											
97											
98	**Allocation Factors**										
99	1 4CP-ERCOT Peak	WP 21 - Demand Alloc				37.8%	3.6%	9.8%	35.3%	2.7%	4.3%
100						3,546,463	338,413	923,786	3,313,242	256,860	407,876
101											
102	2 12NCP Primary	WP 21 - Demand Alloc				38.8%	4.1%	9.3%	34.0%	2.7%	4.7%
103	12NCP, Excluding Transmission			26,268,927		10,197,519	1,079,846	2,454,085	8,940,505	711,688	1,234,975
104	12NCP			26,690,177		10,197,519	1,079,846	2,454,085	8,940,505	711,688	1,234,975
105	Remove Transmission Related 12NCP			(421,250)		-	-	-	-	-	-
106											
107	3 Sum Max Demands	WP 21 - Demand Alloc				54.8%	2.8%	7.3%	25.1%	2.3%	2.9%
108	Sum of Maximum Demands					22,668,750	1,155,332	3,000,305	10,370,350	935,115	1,195,446
109											
110	4 Rev Req					41.9%	4.1%	8.2%	30.7%	2.5%	4.5%
111	Proportion of Revenue Requirement					475,923,675	46,012,213	93,559,500	348,983,791	28,921,794	51,229,379
112											
113	5 Rev Req Excl COA Lights					42.3%	4.1%	8.3%	31.0%	2.6%	4.6%
114	Proportion of Revenue Requirement with City of Austin Street Lighting Redistributed					480,335,595	46,438,756	94,426,817	352,218,949	29,189,906	51,704,287
115											
116	6 kWh Sold	WP 21 - Demand Alloc				32.7%	3.2%	8.4%	35.1%	3.4%	6.5%
117						3,864,401,370	378,885,207	987,036,795	4,142,609,008	405,947,626	769,829,965
118											
119	7 No. Cust Mo.	WP 22 - Cust Alloc				88.8%	7.8%	2.5%	0.8%	0.0%	0.0%
120	Total Number of Customer Months					4,374,252	384,008	124,321	38,566	1,224	240
121											
122	8 City-Owned Lighting	WP 22 - Cust Alloc				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
123	Allocation of Distribution Costs Associated with City-Owned Lighting Based on Bulb Count					-	-	-	-	-	-
124											
125	9 12NCP Secondary	WP 21 - Demand Alloc				44.6%	4.7%	10.7%	39.1%	0.0%	0.0%
126	12NCP for Secondary Service Level Only			22,865,502		10,197,519	1,079,846	2,454,085	8,940,505	-	-
127	12NCP			26,690,177		10,197,519	1,079,846	2,454,085	8,940,505	711,688	1,234,975
128	Remove Non-Secondary Service Related 12NCP			(3,824,675)		-	-	-	-	(711,688)	(1,234,975)
129											

Test Year Cost of Service

Purpose: Identify the Cost of Service by Customer Class

Line No.			Rate Design (On-Peak = June - Sept)	TOU Period	Test Year	Allocation Basis	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW
A			B	C	D	E	F	G	H	I	J	K
130	10	SMD Excl Primary & Trans	WP 21 - Demand Alloc				60.6%	3.1%	8.0%	27.7%	0.0%	0.0%
131		Sum of Maximum Demands, Excluding Primary and Transmission					22,668,750	1,155,332	3,000,305	10,370,350	-	-
132		Sum of Maximum Demands			41,358,581		22,668,750	1,155,332	3,000,305	10,370,350	935,115	1,195,446
133		Remove Primary and Transmission Related			(3,970,717)		-	-	-	-	(935,115)	(1,195,446)
134												
135	11	Sum Max Demands - S	WP 21 - Demand Alloc				55.1%	2.6%	7.5%	25.1%	2.3%	2.8%
136		Sum of Maximum Demands for Summer (June - Sept)					8,152,718	385,302	1,110,031	3,710,473	344,768	411,092
137												
138	12	kWh Sold - S	WP 21 - Demand Alloc				37.9%	3.0%	8.0%	33.0%	3.2%	5.7%
139		kWh Sold During Summer Months (June - Sept)					1,832,044,412	144,102,118	385,685,698	1,598,520,610	157,106,615	277,985,057
140												
141	13	No. Cust Mo. - S	WP 22 - Cust Alloc				88.8%	7.8%	2.5%	0.8%	0.0%	0.0%
142		Customer-Months in Summer (June - Sept) - Based on 4/12 of Annual Customer-Months					1,458,084	128,003	41,440	12,855	408	80
143												
144	14	GC $ Sold	WP 44.1 - PCR				23.7%	3.7%	10.9%	58.8%	2.9%	0.0%
145							2,384,764	375,868	1,092,030	5,908,653	294,821	-
146												
147	15	COA Street Lights					0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
148		Direct Assignment to City-Owned Street Lighting										
149												
150	16	Key Acct	WP 38 - Key Acct				0.5%	9.9%	15.1%	46.9%	6.8%	15.1%
151							0	0	0	0	0	0
152												
153	17	Ave & Excess	WP 21 - Demand Alloc				41.2%	3.5%	9.0%	32.7%	2.6%	4.2%
154							1,026,759	86,818	225,359	815,032	65,436	105,581
155												
156	18	Uncollectible	WP 17 - Uncollectible				90.3%	7.7%	2.0%	0.0%	0.0%	0.0%
157							4,217,429	359,856	92,502	-	-	-
158												
159	19	Weighted Cust - Meters	WP 30 - Meters				71.9%	18.3%	5.9%	3.1%	0.5%	0.1%
160							85,297,914	21,664,455	7,013,766	3,654,165	606,084	118,840
161												
162	20	NEFL Net GC	WP 21 - Demand Alloc				33.1%	3.2%	8.3%	34.7%	3.4%	6.5%
163		NEFL, Excluding Green Choice			12,116,190,284		4,012,303,885	389,278,432	1,010,447,170	4,202,839,722	408,660,848	792,414,476
164		Net Energy for Load			12,382,099,708		4,069,979,479	399,041,111	1,039,545,098	4,362,987,184	417,856,916	792,414,476
165		Remove NEFL Associated with Green Choice			(265,909,424)		(57,675,594)	(9,762,679)	(29,097,928)	(160,147,462)	(9,196,068)	-
166												
167	21	NEFL Net GC - S	WP 21 - Demand Alloc & WP 23 - Line Loss				38.3%	3.0%	7.9%	32.6%	3.2%	5.8%
168		NEFL for the Summer Season - Based on kWh Sold Net GC and Losses by Service Level					1,901,741,252	147,778,422	394,118,762	1,618,016,571	158,417,738	286,140,308
169		kWh Sold, Excluding GC, During Summer Months (June - Sept)					1,805,682,692	140,314,009	374,211,490	1,536,289,184	153,902,693	277,985,057
170		Percent Average Losses by Service Level					5.05%	5.05%	5.05%	5.05%	2.85%	2.85%
171		kWh Losses					96,058,560	7,464,413	19,907,272	81,727,387	4,515,045	8,155,251
172												
173	22	NEFL Net GC Excl COA	WP 21 - Demand Alloc				33.2%	3.2%	8.4%	34.8%	3.4%	6.6%
174		NEFL, Excluding Green Choice and COA Street Lighting					4,012,303,885	389,278,432	1,010,447,170	4,202,839,722	408,660,848	792,414,476
175		Net Energy for Load			12,382,099,708		4,069,979,479	399,041,111	1,039,545,098	4,362,987,184	417,856,916	792,414,476
176		Remove NEFL Associated with Green Choice			(265,909,424)		(57,675,594)	(9,762,679)	(29,097,928)	(160,147,462)	(9,196,068)	-
177		Remove NEFL Associated with COA Lighting			(33,400,720)		-	-	-	-	-	-
178												

Test Year Cost of Service

Purpose: Identify the Cost of Service by Customer Class

Line No.			Rate Design (On-Peak = June - Sept)	TOU Period	Test Year	Allocation Basis	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW
A			B	C	D	E	F	G	H	I	J	K
179	23	kWh Sold Net GC	WP 21 - Demand Alloc				33.0%	3.2%	8.3%	34.5%	3.4%	6.7%
180		kWh Sold, Excluding Green Choice			11,561,258,164		3,809,639,019	369,615,649	959,408,628	3,990,550,730	397,013,654	769,829,965
181		kWh Sold			11,813,938,683		3,864,401,370	378,885,207	987,036,795	4,142,609,008	405,947,626	769,829,965
182		Remove kWh Sold Associated with GC			(252,680,519)		(54,762,351)	(9,269,558)	(27,628,167)	(152,058,278)	(8,933,972)	-
183												
184	24	kWh Sold Net GC - S	WP 21 - Demand Alloc				38.2%	3.0%	7.9%	32.5%	3.3%	5.9%
185		kWh Sold, Excluding GC, During Summer Months (June - Sept)					1,805,682,692	140,314,009	374,211,490	1,536,289,184	153,902,693	277,985,057
186		kWh Sold During Summer Months (June - Sept)			4,838,733,296		1,832,044,412	144,102,118	385,685,698	1,598,520,610	157,106,615	277,985,057
187		Remove GC kWh Sold in the Summer Months			(107,059,386)		(26,361,720)	(3,788,110)	(11,474,208)	(62,231,426)	(3,203,922)	-
188												
189	25	City-Owned Bulb-Mo.	WP 22 - Cust Alloc				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
190		City-Owned Lighting Bulb Count Times 12 Months					-	-	-	-	-	-
191												
192	26	City-Owned Bulb-Mo. - S	WP 22 - Cust Alloc				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
193		City-Owned Lighting Bulb Count Times 4 Months					-	-	-	-	-	-
194												
195	27	No. Cust Mo. - Metered	WP 22 - Cust Alloc				88.9%	7.8%	2.5%	0.8%	0.0%	0.0%
196		Customer-Months for Metered Customer Classes					4,374,252	384,008	124,321	38,566	1,224	240
197		Total Customer-Months					4,374,252	384,008	124,321	38,566	1,224	240
198		Remove Customer-Months Associated with Non-Metered Customer Classes					-	-	-	-	-	-

Test Year Cost of Service

Purpose: Identify the Cost of Service by Custom

Line No.		Primary Voltage ≥ 20 MW	Transmission Voltage	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A		L	M	N	O	P	Q	R
1	**Production**							
2	**Demand Related**							
3	Base Load - Nuclear	$ 8,661,752	$ 2,041,092	$ 573,552	$ 270,919	$ 38,076	$ 234,879	$ 174,998,382
4	Base Load - Coal	3,818,799	899,878	252,868	119,443	16,787	103,554	77,153,403
5	Intermediate - Gas	2,903,387	684,166	192,252	90,811	12,763	78,731	58,658,794
6	Peak - Gas	641,091	151,069	42,451	20,052	2,818	17,384	12,952,332
7	Renewable - Solar	386,030	90,966	25,562	12,074	1,697	10,468	7,799,190
8		$ 16,411,059	$ 3,867,171	$ 1,086,685	$ 513,300	$ 72,141	$ 445,016	$ 331,562,101
9								
10	**Energy Related**							
11	Base Load - Nuclear - Fuel	1,816,709	458,675	60,882	22,201	3,275	8,316	22,085,109
12	Base Load - Coal - Fuel	10,287,113	2,597,248	344,745	125,714	18,545	47,087	125,056,934
13	Intermediate - Gas - Fuel	12,610,021	3,183,727	422,591	154,101	22,733	57,720	153,295,739
14	Peak - Gas - Fuel	809,983	206,639	29,291	9,344	1,394	3,541	11,546,911
15	Economy - Purch Pwr	2,167,619	547,272	72,642	26,489	3,908	9,922	26,351,013
16	Renewable - Wind	5,537,862	1,398,177	185,586	67,676	9,983	25,348	67,321,905
17	Renewable - Solar	1,077,709	272,096	36,117	13,170	1,943	4,933	13,101,348
18	Renewable - LF Methane	311,990	78,770	10,456	3,813	562	1,428	3,792,761
19		$ 34,619,006	$ 8,742,603	$ 1,162,309	$ 422,508	$ 62,343	$ 158,295	$ 422,551,719
20								
21	**Direct Assignments**							
22	Regulatory - Adj Clause	$ 809,416	$ 204,358	$ 27,125	$ 9,891	$ 1,459	$ 3,705	$ 9,839,798
23	Community Benefit - Adj Clause	1,514,017	343,189	254,612	93,335	4,262	20,611	27,720,129
24	Green Choice	-	-	-	-	-	946	10,057,082
25		$ 2,323,433	$ 547,547	$ 281,737	$ 103,226	$ 5,721	$ 25,262	$ 47,617,009
26								
27	**Total Production**	**$ 53,353,498**	**$ 13,157,321**	**$ 2,530,730**	**$ 1,039,034**	**$ 140,206**	**$ 628,573**	**$ 801,730,829**
28								
29								
30	**Transmission**							
31	**Demand Related**							
32	Transmission - By Others	3,371,416	814,868	2,478	-	169	10,147	65,915,251
33		$ 3,371,416	$ 814,868	$ 2,478	$ -	$ 169	$ 10,147	$ 65,915,251
34								
35	**Total Transmission**	**$ 3,371,416**	**$ 814,868**	**$ 2,478**	**$ -**	**$ 169**	**$ 10,147**	**$ 65,915,251**
36								
37								

Test Year Cost of Service

Purpose: Identify the Cost of Service by Custom

Line No.		Primary Voltage ≥ 20 MW	Transmission Voltage	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A		L	M	N	O	P	Q	R
38	**Distribution**							
39	**Demand Related**							
40	Primary - Subs, P&C	$ 4,917,056	$ -	$ 367,049	$ 142,681	$ 20,470	$ 123,085	$ 88,666,341
41	Secondary - P&C	-	-	178,072	69,221	9,931	59,714	37,442,772
42	Transformers	-	-	52,023	18,971	2,799	7,152	15,670,208
43	Services	-	-	(3,948)	(1,440)	(212)	(543)	(1,189,256)
44	Load Dispatch	272,789	-	20,363	7,916	1,136	6,829	4,919,046
45		$ 5,189,845	$ -	$ 613,560	$ 237,348	$ 34,123	$ 196,236	$ 145,509,111
46								
47	**Customer Related**							
48	Meters	$ 3,530	$ 43,450	$ -	$ -	$ -	$ 1,329	$ 17,108,086
49		$ 3,530	$ 43,450	$ -	$ -	$ -	$ 1,329	$ 17,108,086
50								
51	**Direct Assignments**							
52	City-Owned - Lighting	$ -	$ -	$ 7,287,020	$ 2,548,637	$ -	$ -	$ 9,835,657
53		$ -	$ -	$ 7,287,020	$ 2,548,637	$ -	$ -	$ 9,835,657
54								
55	**Total Distribution**	**$ 5,193,375**	**$ 43,450**	**$ 7,900,580**	**$ 2,785,985**	**$ 34,123**	**$ 197,565**	**$ 172,452,854**
56								
57								
58	**Customer**							
59	**Customer Related**							
60	Customer - Accounting	$ 325	$ 325	$ 325	$ -	$ 81	$ 3,204	$ 33,372,851
61	Customer - Service	325	325	325	-	81	3,198	33,301,847
62	Meter - Reading	204	204	-	-	-	2,008	20,913,388
63	Uncollectibles	-	-	-	-	-	-	5,261,706
64	Key - Accounts	128,003	48,001	-	-	-	-	3,072,075
65		$ 128,857	$ 48,855	$ 650	$ -	$ 163	$ 8,410	$ 95,921,868
66								
67	**Total Customer**	**$ 128,857**	**$ 48,855**	**$ 650**	**$ -**	**$ 163**	**$ 8,410**	**$ 95,921,868**
68								
69								
70	**Total Cost of Service**	**$ 62,047,146**	**$ 14,064,494**	**$ 10,434,438**	**$ 3,825,018**	**$ 174,660**	**$ 844,695**	**$ 1,136,020,803**
71								
72	**Adjustment to Redistribute Service Area Stre**							
73	Street Lighting - Service Area Cost	$ -	$ -	$ (10,434,438)	$ -	$ -	$ -	$ (10,434,438)
74	Street Lighting - Redistributed	575,191	130,381	-	35,459	1,619	7,831	10,434,438
75		$ 575,191	$ 130,381	$ (10,434,438)	$ 35,459	$ 1,619	$ 7,831	$ (0)
76								
77	**Adjusted Total Cost of Service**	**$ 62,622,337**	**$ 14,194,875**	**$ -**	**$ 3,860,477**	**$ 176,279**	**$ 852,526**	**$ 1,136,020,803**
78								
79								

Test Year Cost of Service

Purpose: Identify the Cost of Service by Custom

Line No.		Primary Voltage ≥ 20 MW	Transmission Voltage	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A		L	M	N	O	P	Q	R
80								
81	**Revenue Adequacy Check - FY 2009 Rate Stru**							
82	**Base Rate Revenue**	**$ 25,400,023**	**$ 7,698,549**	**$ -**	**$ 1,562,396**	**$ 73,171**	**$ 227,796**	**$ 604,256,828**
83								
84	**Revenue from Adjustment Clauses**							
85	Recoverable Fuel	$ 32,155,013	$ 8,118,366	$ 1,077,588	$ 392,951	$ 57,968	$ 147,183	$ 390,897,575
86	Green Choice	-	-	-	-	-	946	10,057,082
87	Remove Service Area Street Lighting F	-	-	(1,077,588)	-	-	-	(1,077,588)
88		**$ 32,155,013**	**$ 8,118,366**	**$ -**	**$ 392,951**	**$ 57,968**	**$ 148,129**	**$ 399,877,069**
89								
90	**Total Rate Revenue**	**$ 57,555,036**	**$ 15,816,915**	**$ -**	**$ 1,955,348**	**$ 131,138**	**$ 375,924**	**$ 1,004,133,897**
91								
92								
93	**Over/(Short)**	**$ (5,067,301)**	**$ 1,622,040**	**$ -**	**$ (1,905,130)**	**$ (45,141)**	**$ (476,601)**	**$ (131,886,905)**
94								
95	*Required Increase / (Decrease) in Rate*	*8.8%*	*-10.3%*		*97.4%*	*34.4%*	*126.8%*	
96								
97								
98	**Allocation Factors**							
99	1 4CP-ERCOT Peak	5.1%	1.2%	0.0%	0.0%	0.0%	0.0%	100.0%
100		479,994	116,014	353	-	24	1,445	9,384,470
101								
102	2 12NCP Primary	5.5%	0.0%	0.4%	0.2%	0.0%	0.1%	100.0%
103	12NCP, Excluding Transmis	1,456,762	-	108,745	42,272	6,065	36,466	26,268,927
104	12NCP	1,456,762	421,250	108,745	42,272	6,065	36,466	
105	Remove Transmission Rela	-	(421,250)	-	-	-	-	
106								
107	3 Sum Max Demands	3.5%	1.0%	0.3%	0.1%	0.0%	0.0%	100.0%
108	Sum of Maximum Demanc	1,431,533	408,622	124,124	45,263	6,677	17,064	41,358,581
109								
110	4 Rev Req	5.5%	1.2%	0.9%	0.3%	0.0%	0.1%	100.0%
111	Proportion of Revenue Re	62,047,146	14,064,494	10,434,438	3,825,018	174,660	844,695	1,136,020,803
112								
113	5 Rev Req Excl COA Lights	5.5%	1.2%	0.0%	0.3%	0.0%	0.1%	100.0%
114	Proportion of Revenue Re	62,622,337	14,194,875	-	3,860,477	176,279	852,526	1,136,020,803
115								
116	6 kWh Sold	8.2%	2.1%	0.3%	0.1%	0.0%	0.0%	100.0%
117		968,264,949	247,619,682	31,713,621	11,564,634	1,706,004	4,359,820	11,813,938,683
118								
119	7 No. Cust Mo.	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
120	Total Number of Custome	48	48	48	-	12	473	4,923,240
121								
122	8 City-Owned Lighting	0.0%	0.0%	74.1%	25.9%	0.0%	0.0%	100.0%
123	Allocation of Distribution (	-	-	43,431	15,190	-	-	58,621
124								
125	9 12NCP Secondary	0.0%	0.0%	0.5%	0.2%	0.0%	0.2%	100.0%
126	12NCP for Secondary Serv	-	-	108,745	42,272	6,065	36,466	22,865,502
127	12NCP	1,456,762	421,250	108,745	42,272	6,065	36,466	
128	Remove Non-Secondary S	(1,456,762)	(421,250)	-	-	-	-	
129								

Test Year Cost of Service

Purpose: Identify the Cost of Service by Custom

Line No.			Primary Voltage ≥ 20 MW	Transmission Voltage	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A			L	M	N	O	P	Q	R
130	10	SMD Excl Primary & Trans	0.0%	0.0%	0.3%	0.1%	0.0%	0.0%	100.0%
131		Sum of Maximum Demanc	-	-	124,124	45,263	6,677	17,064	37,387,865
132		Sum of Maximum Demanc	1,431,533	408,622	124,124	45,263	6,677	17,064	
133		Remove Primary and Tran:	(1,431,533)	(408,622)	-	-	-	-	
134									
135	11	Sum Max Demands - S	3.3%	0.9%	0.3%	0.1%	0.0%	0.0%	100.0%
136		Sum of Maximum Demanc	483,896	139,911	46,775	14,921	2,226	5,654	14,807,767
137									
138	12	kWh Sold - S	7.0%	1.8%	0.2%	0.1%	0.0%	0.0%	100.0%
139		kWh Sold During Summer	338,135,114	87,377,150	11,950,939	3,812,307	568,668	1,444,608	4,838,733,296
140									
141	13	No. Cust Mo. - S	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
142		Customer-Months in Sumr	16	16	16	-	4	158	1,641,080
143									
144	14	GC $ Sold	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
145			-	-	-	-	-	946	10,057,082
146									
147	15	COA Street Lights	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	100.0%
148		Direct Assignment to City-			1				1
149									
150	16	Key Acct	4.2%	1.6%	0.0%	0.0%	0.0%	0.0%	100.0%
151			0	0	-	-	-	-	1
152									
153	17	Ave & Excess	4.9%	1.2%	0.3%	0.2%	0.0%	0.1%	100.0%
154			123,414	29,082	8,172	3,860	543	3,347	2,493,400
155									
156	18	Uncollectible	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
157			-	-	-	-	-	-	4,669,787
158									
159	19	Weighted Cust - Meters	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	100.0%
160			24,488	301,440	-	-	-	9,218	118,690,371
161									
162	20	NEFL Net GC	8.2%	2.1%	0.3%	0.1%	0.0%	0.0%	100.0%
163		NEFL, Excluding Green Chc	996,670,950	251,635,412	33,400,720	12,179,848	1,796,760	4,562,062	12,116,190,284
164		Net Energy for Load	996,670,950	251,635,412	33,400,720	12,179,848	1,796,760	4,591,753	
165		Remove NEFL Associated \	-	-	-	-	-	(29,692)	
166									
167	21	NEFL Net GC - S	7.0%	1.8%	0.3%	0.1%	0.0%	0.0%	100.0%
168		NEFL for the Summer Seas	348,054,987	88,794,174	12,586,704	4,015,114	598,920	1,521,458	4,961,784,410
169		kWh Sold, Excluding GC, D	338,135,114	87,377,150	11,950,939	3,812,307	568,668	1,444,608	
170		Percent Average Losses by	2.85%	1.60%	5.05%	5.05%	5.05%	5.05%	
171		kWh Losses	9,919,874	1,417,024	635,765	202,807	30,252	76,850	
172									
173	22	NEFL Net GC Excl COA	8.2%	2.1%	0.0%	0.1%	0.0%	0.0%	100.0%
174		NEFL, Excluding Green Chc	996,670,950	251,635,412	-	12,179,848	1,796,760	4,562,062	12,082,789,564
175		Net Energy for Load	996,670,950	251,635,412	33,400,720	12,179,848	1,796,760	4,591,753	
176		Remove NEFL Associated \	-	-	-	-	-	(29,692)	
177		Remove NEFL Associated \	-	-	(33,400,720)	-	-	-	
178									

Test Year Cost of Service
Purpose: Identify the Cost of Service by Custom

Line No.			Primary Voltage ≥ 20 MW	Transmission Voltage	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A			L	M	N	O	P	Q	R
179	23	kWh Sold Net GC	8.4%	2.1%	0.3%	0.1%	0.0%	0.0%	100.0%
180		kWh Sold, Excluding Greer	968,264,949	247,619,682	31,713,621	11,564,634	1,706,004	4,331,628	11,561,258,164
181		kWh Sold	968,264,949	247,619,682	31,713,621	11,564,634	1,706,004	4,359,820	
182		Remove kWh Sold Associa	-	-	-	-	-	(28,192)	
183									
184	24	kWh Sold Net GC - S	7.1%	1.8%	0.3%	0.1%	0.0%	0.0%	100.0%
185		kWh Sold, Excluding GC, D	338,135,114	87,377,150	11,950,939	3,812,307	568,668	1,444,608	4,731,673,910
186		kWh Sold During Summer	338,135,114	87,377,150	11,950,939	3,812,307	568,668	1,444,608	
187		Remove GC kWh Sold in th	-	-	-	-	-	-	
188									
189	25	City-Owned Bulb-Mo.	0.0%	0.0%	74.1%	25.9%	0.0%	0.0%	100.0%
190		City-Owned Lighting Bulb (	-	-	521,172	182,280	-	-	703,452
191									
192	26	City-Owned Bulb-Mo. - S	0.0%	0.0%	74.1%	25.9%	0.0%	0.0%	100.0%
193		City-Owned Lighting Bulb (	-	-	173,724	60,760	-	-	234,484
194									
195	27	No. Cust Mo. - Metered	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
196		Customer-Months for Met	48	48	-	-	-	473	4,923,180
197		Total Customer-Months	48	48	48	-	12	473	
198		Remove Customer-Month:	-	-	(48)	-	(12)	-	

Test Year Adjustment Clauses

Purpose: Calculate the Appropriate Pass-Throughs Based on Cost of Service and Level of Recovery within Base Rates

Line No.		Source Reference	Test Year	Allocation Basis	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW
A		B	C	D	E	F	G	H	I	J
1	**Energy Adjustment**									
2	**Fuel and Purchase Power Costs**									
3	Recoverable Fuel Costs	Functional Unbundling	$ 390,897,575	NEFL Net GC	$ 129,446,618	$ 12,559,063	$ 32,599,467	$ 135,593,765	$ 13,184,386	$ 25,565,206
4	Green Choice Billed	Functional Unbundling	10,057,082	GC $ Sold	2,384,764	375,868	1,092,030	5,908,653	294,821	-
5			$ 400,954,657		$ 131,831,383	$ 12,934,931	$ 33,691,497	$ 141,502,418	$ 13,479,208	$ 25,565,206
6										
7	**Service Area Street Lighting Recoverable Fuel and Purchase Power**									
8	Street Lighting - Service Area Cost		$ (1,077,588)	COA Street Lights	$ -	$ -	$ -	$ -	$ -	$ -
9										
10	**Adjusted Fuel and Purchase Power Costs**									
11	Recoverable Fuel Costs		$ 389,819,987		$ 129,446,618	$ 12,559,063	$ 32,599,467	$ 135,593,765	$ 13,184,386	$ 25,565,206
12	Green Choice Billed		10,057,082		2,384,764	375,868	1,092,030	5,908,653	294,821	-
13			$ 399,877,069		$ 131,831,383	$ 12,934,931	$ 33,691,497	$ 141,502,418	$ 13,479,208	$ 25,565,206
14										
15	**Recoverable Fuel Costs**		**$ 389,819,987**		**$ 129,446,618**	**$ 12,559,063**	**$ 32,599,467**	**$ 135,593,765**	**$ 13,184,386**	**$ 25,565,206**
16										
17	**Portion Recovered in Base Rate**	Manual Input	$ 389,819,987	NEFL Net GC Excl COA	$ 129,446,618	$ 12,559,063	$ 32,599,467	$ 135,593,765	$ 13,184,386	$ 25,565,206
18										
19	**Net to be Recovered in the Energy Adjustment**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
20										
21	**Regulatory**									
22	**Cost of Service Expenses Eligible to be Recovered in Regulatory**									
23	Transmission of Electricity by Others (FERC 565)	COS	$ 65,915,251	4CP-ERCOT Peak	$ 24,909,876	$ 2,376,967	$ 6,488,552	$ 23,271,767	$ 1,804,147	$ 2,864,866
24	Production Direct Assignments to Regulatory	COS	9,839,798	NEFL Net GC	3,258,472	316,141	820,604	3,413,209	331,882	643,536
25			$ 75,755,050		$ 28,168,347	$ 2,693,107	$ 7,309,156	$ 26,684,976	$ 2,136,029	$ 3,508,401
26										
27	**Portion Recovered in Base Rate**									
28	Transmission of Electricity by Others (FERC 565)	Manual Input	$ -	4CP-ERCOT Peak	$ -	$ -	$ -	$ -	$ -	$ -
29	Production Direct Assignments to Regulatory	Manual Input	-	NEFL Net GC	-	-	-	-	-	-
30			$ -		$ -	$ -	$ -	$ -	$ -	$ -
31										
32	**Net to be Recovered in Regulatory**									
33	Transmission of Electricity by Others (FERC 565)		$ 65,915,251		$ 24,909,876	$ 2,376,967	$ 6,488,552	$ 23,271,767	$ 1,804,147	$ 2,864,866
34	Production Direct Assignments to Regulatory		9,839,798		3,258,472	316,141	820,604	3,413,209	331,882	643,536
35			**$ 75,755,050**		**$ 28,168,347**	**$ 2,693,107**	**$ 7,309,156**	**$ 26,684,976**	**$ 2,136,029**	**$ 3,508,401**
36										
37	**Community Benefit**									
38	**Cost of Service Expenses Eligible to be Recovered in Community Benefit**									
39	City-Owned (Service Area) Street Lighting	COS	$ 10,434,438	Rev Req Excl COA Lights	$ 4,411,919	$ 426,544	$ 867,318	$ 3,235,158	$ 268,112	$ 474,908
40	Production Direct Assignments to Community Benefit	COS	27,720,129	Rev Req	11,613,049	1,122,747	2,282,952	8,515,580	705,723	1,250,052
41			$ 38,154,567		$ 16,024,969	$ 1,549,291	$ 3,150,270	$ 11,750,738	$ 973,834	$ 1,724,960
42										
43	**Portion Recovered in Base Rate**									
44	City-Owned (Service Area) Street Lighting	Manual Input	$ -	Rev Req Excl COA Lights	$ -	$ -	$ -	$ -	$ -	$ -
45	Production Direct Assignments to Community Benefit	Manual Input	-	Rev Req	-	-	-	-	-	-
46			$ -		$ -	$ -	$ -	$ -	$ -	$ -
47										
48	**Net to be Recovered in Community Benefit**									
49	City-Owned (Service Area) Street Lighting		$ 10,434,438		$ 4,411,919	$ 426,544	$ 867,318	$ 3,235,158	$ 268,112	$ 474,908
50	Production Direct Assignments to Community Benefit		27,720,129		11,613,049	1,122,747	2,282,952	8,515,580	705,723	1,250,052
51			**$ 38,154,567**		**$ 16,024,969**	**$ 1,549,291**	**$ 3,150,270**	**$ 11,750,738**	**$ 973,834**	**$ 1,724,960**

Test Year Adjustment Clauses

Purpose: Calculate the Appropriate Pass-Throughs Based on Cost of Service and Level of Recovery within Base Rates

Line No.		Source Reference	Test Year	Primary Voltage ≥ 20 MW	Transmission Voltage	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A		B	C	K	L	M	N	O	P	Q
1	**Energy Adjustment**									
2	**Fuel and Purchase Power Costs**									
3	Recoverable Fuel Costs	Functional Unbundling	$ 390,897,575	$ 32,155,013	$ 8,118,366	$ 1,077,588	$ 392,951	$ 57,968	$ 147,183	$ 390,897,575
4	Green Choice Billed	Functional Unbundling	10,057,082	-	-	-	-	-	946	10,057,082
5			$ 400,954,657	$ 32,155,013	$ 8,118,366	$ 1,077,588	$ 392,951	$ 57,968	$ 148,129	$ 400,954,657
6										
7	**Service Area Street Lighting Recoverable Fuel and Purchase Power**									
8	Street Lighting - Service Area Cost		$ (1,077,588)	$ -	$ -	$ (1,077,588)	$ -	$ -	$ -	$ (1,077,588)
9										
10	**Adjusted Fuel and Purchase Power Costs**									
11	Recoverable Fuel Costs		$ 389,819,987	$ 32,155,013	$ 8,118,366	$ -	$ 392,951	$ 57,968	$ 147,183	$ 389,819,987
12	Green Choice Billed		10,057,082	-	-	-	-	-	946	10,057,082
13			$ 399,877,069	$ 32,155,013	$ 8,118,366	$ -	$ 392,951	$ 57,968	$ 148,129	$ 399,877,069
14										
15	**Recoverable Fuel Costs**		**$ 389,819,987**	**$ 32,155,013**	**$ 8,118,366**	**$ -**	**$ 392,951**	**$ 57,968**	**$ 147,183**	**$ 389,819,987**
16										
17	**Portion Recovered in Base Rate**	Manual Input	$ 389,819,987	$ 32,155,013	$ 8,118,366	$ -	$ 392,951	$ 57,968	$ 147,183	$ 389,819,987
18										
19	**Net to be Recovered in the Energy Adjustment**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
20										
21	**Regulatory**									
22	**Cost of Service Expenses Eligible to be Recovered in Regulatory**									
23	Transmission of Electricity by Others (FERC 565)	COS	$ 65,915,251	$ 3,371,416	$ 814,868	$ 2,478	$ -	$ 169	$ 10,147	$ 65,915,251
24	Production Direct Assignments to Regulatory	COS	9,839,798	809,416	204,358	27,125	9,891	1,459	3,705	9,839,798
25			$ 75,755,050	$ 4,180,832	$ 1,019,226	$ 29,603	$ 9,891	$ 1,628	$ 13,852	$ 75,755,050
26										
27	**Portion Recovered in Base Rate**									
28	Transmission of Electricity by Others (FERC 565)	Manual Input	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Production Direct Assignments to Regulatory	Manual Input	-	-	-	-	-	-	-	-
30			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31										
32	**Net to be Recovered in Regulatory**									
33	Transmission of Electricity by Others (FERC 565)		$ 65,915,251	$ 3,371,416	$ 814,868	$ 2,478	$ -	$ 169	$ 10,147	$ 65,915,251
34	Production Direct Assignments to Regulatory		9,839,798	809,416	204,358	27,125	9,891	1,459	3,705	9,839,798
35			**$ 75,755,050**	**$ 4,180,832**	**$ 1,019,226**	**$ 29,603**	**$ 9,891**	**$ 1,628**	**$ 13,852**	$ 75,755,050
36										
37	**Community Benefit**									
38	**Cost of Service Expenses Eligible to be Recovered in Community Benefit**									
39	City-Owned (Service Area) Street Lighting	COS	$ 10,434,438	$ 575,191	$ 130,381	$ -	$ 35,459	$ 1,619	$ 7,831	$ 10,434,438
40	Production Direct Assignments to Community Benefit	COS	27,720,129	1,514,017	343,189	254,612	93,335	4,262	20,611	27,720,129
41			$ 38,154,567	$ 2,089,208	$ 473,570	$ 254,612	$ 128,793	$ 5,881	$ 28,442	$ 38,154,567
42										
43	**Portion Recovered in Base Rate**									
44	City-Owned (Service Area) Street Lighting	Manual Input	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	Production Direct Assignments to Community Benefit	Manual Input	-	-	-	-	-	-	-	-
46			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47										
48	**Net to be Recovered in Community Benefit**									
49	City-Owned (Service Area) Street Lighting		$ 10,434,438	$ 575,191	$ 130,381	$ -	$ 35,459	$ 1,619	$ 7,831	$ 10,434,438
50	Production Direct Assignments to Community Benefit		27,720,129	1,514,017	343,189	254,612	93,335	4,262	20,611	27,720,129
51			**$ 38,154,567**	**$ 2,089,208**	**$ 473,570**	**$ 254,612**	**$ 128,793**	**$ 5,881**	**$ 28,442**	$ 38,154,567

Test Year Cost of Service for Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW	Primary Voltage ≥ 20 MW	Transmission Voltage
A		B	C	D	E	F	G	H	I	J	K
1	**Unbundled Cost Summary - Base Rates**										
2	**COST OF SERVICE SUMMARY**										
3	**Production**										
4	**Demand**										
5	On-Peak	$ 12,952,332		$ 5,333,648	$ 450,988	$ 1,170,659	$ 4,233,801	$ 339,916	$ 548,453	$ 641,091	$ 151,069
6	Annual	356,169,696		146,072,017	12,532,589	31,900,184	116,074,542	9,399,079	15,384,798	18,093,401	4,263,649
7	Total Demand	$ 369,122,028		$ 151,405,665	$ 12,983,578	$ 33,070,843	$ 120,308,343	$ 9,738,995	$ 15,933,252	$ 18,734,492	$ 4,414,718
8											
9	**Pass-Throughs**										
10	Regulatory On-Peak	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Regulatory Annual	9,839,798		3,258,472	316,141	820,604	3,413,209	331,882	643,536	809,416	204,358
12	Community Benefit On-Peak	-		-	-	-	-	-	-	-	-
13	Community Benefit Annual	27,720,129		11,613,049	1,122,747	2,282,952	8,515,580	705,723	1,250,052	1,514,017	343,189
14	Total Pass-Throughs	$ 37,559,927		$ 14,871,521	$ 1,438,888	$ 3,103,557	$ 11,928,789	$ 1,037,604	$ 1,893,587	$ 2,323,433	$ 547,547
15											
16	**Net Recovered from Base Rates**										
17	On-Peak	$ 12,952,332		$ 5,333,648	$ 450,988	$ 1,170,659	$ 4,233,801	$ 339,916	$ 548,453	$ 641,091	$ 151,069
18	Annual	318,609,769		131,200,496	11,093,701	28,796,627	104,145,753	8,361,475	13,491,211	15,769,968	3,716,102
19	Total Net Recovered from Base Rates	$ 331,562,101		$ 136,534,144	$ 11,544,690	$ 29,967,286	$ 108,379,553	$ 8,701,391	$ 14,039,664	$ 16,411,059	$ 3,867,171
20											
21	*On-Peak (June - September)*	$ 12,952,332		$ 5,333,648	$ 450,988	$ 1,170,659	$ 4,233,801	$ 339,916	$ 548,453	$ 641,091	$ 151,069
22	Summer Billed Demand	14,807,767	Sum Max Demands - S	8,152,718	385,302	1,110,031	3,710,473	344,768	411,092	483,896	139,911
23	Summer Demand Charge Adder ($/kW)	$ 0.87		$ 0.65	$ 1.17	$ 1.05	$ 1.14	$ 0.99	$ 1.33	$ 1.32	$ 1.08
24	Summer Billed Energy	4,838,733,296	kWh Sold - S	1,832,044,412	144,102,118	385,685,698	1,598,520,610	157,106,615	277,985,057	338,135,114	87,377,150
25	Summer Energy Charge Adder ($/kWh)	$ 0.002677		$ 0.002911	$ 0.003130	$ 0.003035	$ 0.002649	$ 0.002164	$ 0.001973	$ 0.001896	$ 0.001729
26											
27	*All Months*	$ 318,609,769		$ 131,200,496	$ 11,093,701	$ 28,796,627	$ 104,145,753	$ 8,361,475	$ 13,491,211	$ 15,769,968	$ 3,716,102
28	Annual Billed Demand	41,358,581	Sum Max Demands	22,668,750	1,155,332	3,000,305	10,370,350	935,115	1,195,446	1,431,533	408,622
29	Annual Demand Charge ($/kW)	$ 7.70		$ 5.79	$ 9.60	$ 9.60	$ 10.04	$ 8.94	$ 11.29	$ 11.02	$ 9.09
30	Annual Billed Energy	11,813,938,683	kWh Sold	3,864,401,370	378,885,207	987,036,795	4,142,609,008	405,947,626	769,829,965	968,264,949	247,619,682
31	Annual Energy Charge ($/kWh)	$ 0.026969		$ 0.033951	$ 0.029280	$ 0.029175	$ 0.025140	$ 0.020597	$ 0.017525	$ 0.016287	$ 0.015007
32											
33	*Production Demand Related Summary*										
34	On-Peak Demand Charge ($/kW)	**$ 8.58**		**$ 6.44**	**$ 10.77**	**$ 10.65**	**$ 11.18**	**$ 9.93**	**$ 12.62**	**$ 12.34**	**$ 10.17**
35	Off-Peak Demand Charge ($/kW)	**$ 7.70**		**$ 5.79**	**$ 9.60**	**$ 9.60**	**$ 10.04**	**$ 8.94**	**$ 11.29**	**$ 11.02**	**$ 9.09**
36	On-Peak Demand Charge ($/kWh)	**$ 0.029646**		**$ 0.036862**	**$ 0.032409**	**$ 0.032210**	**$ 0.027789**	**$ 0.022761**	**$ 0.019498**	**$ 0.018183**	**$ 0.016736**
37	Off-Peak Demand Charge ($/kWh)	**$ 0.026969**		**$ 0.033951**	**$ 0.029280**	**$ 0.029175**	**$ 0.025140**	**$ 0.020597**	**$ 0.017525**	**$ 0.016287**	**$ 0.015007**
38											
39	**Energy**										
40	On-Peak	$ 11,546,911		$ 4,425,673	$ 343,905	$ 917,181	$ 3,765,398	$ 368,665	$ 665,897	$ 809,983	$ 206,639
41	Annual	421,061,891		138,489,938	13,580,952	35,368,369	148,477,175	14,157,394	26,880,245	33,809,023	8,535,964
42	Total Energy	$ 432,608,801		$ 142,915,612	$ 13,924,857	$ 36,285,550	$ 152,242,573	$ 14,526,059	$ 27,546,142	$ 34,619,006	$ 8,742,603
43											
44	**Pass-Throughs**										
45	Energy Adjustment On-Peak	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Energy Adjustment Annual	-		-	-	-	-	-	-	-	-
47	Green Choice On-Peak	-		-	-	-	-	-	-	-	-
48	Green Choice Annual	10,057,082		2,384,764	375,868	1,092,030	5,908,653	294,821	-	-	-
49	Total Pass-Throughs	$ 10,057,082		$ 2,384,764	$ 375,868	$ 1,092,030	$ 5,908,653	$ 294,821	$ -	$ -	$ -
50											
51	**Net Recovered from Base Rates**										
52	On-Peak	$ 11,546,911		$ 4,425,673	$ 343,905	$ 917,181	$ 3,765,398	$ 368,665	$ 665,897	$ 809,983	$ 206,639
53	Annual	411,004,809		136,105,174	13,205,084	34,276,339	142,568,522	13,862,573	26,880,245	33,809,023	8,535,964
54	Total Net Recovered from Base Rates	$ 422,551,719		$ 140,530,848	$ 13,548,989	$ 35,193,520	$ 146,333,920	$ 14,231,238	$ 27,546,142	$ 34,619,006	$ 8,742,603
55											
56	*On-Peak (June - September)*	$ 11,546,911		$ 4,425,673	$ 343,905	$ 917,181	$ 3,765,398	$ 368,665	$ 665,897	$ 809,983	$ 206,639
57											

Test Year Cost of Service for Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW	Primary Voltage ≥ 20 MW	Transmission Voltage
A		B	C	D	E	F	G	H	I	J	K
58											
59	Summer Billed Energy	4,731,673,910	kWh Sold Net GC - S	1,805,682,692	140,314,009	374,211,490	1,536,289,184	153,902,693	277,985,057	338,135,114	87,377,150
60	Summer Energy Charge Adder ($/kWh)	$ 0.002440		$ 0.002451	$ 0.002451	$ 0.002451	$ 0.002451	$ 0.002395	$ 0.002395	$ 0.002395	$ 0.002365
61											
62	*All Months*	$ 411,004,809		$ 136,105,174	$ 13,205,084	$ 34,276,339	$ 142,568,522	$ 13,862,573	$ 26,880,245	$ 33,809,023	$ 8,535,964
63											
64											
65	Annual Billed Energy	11,561,258,164	kWh Sold Net GC	3,809,639,019	369,615,649	959,408,628	3,990,550,730	397,013,654	769,829,965	968,264,949	247,619,682
66	Annual Energy Charge ($/kWh)	$ 0.035550		$ 0.035727	$ 0.035727	$ 0.035727	$ 0.035727	$ 0.034917	$ 0.034917	$ 0.034917	$ 0.034472
67											
68	*Production Energy Related Summary*										
69											
70											
71	On-Peak Energy Charge ($/kWh)	**$ 0.037991**		**$ 0.038177**	**$ 0.038177**	**$ 0.038177**	**$ 0.038177**	**$ 0.037313**	**$ 0.037313**	**$ 0.037313**	**$ 0.036837**
72	Off-Peak Energy Charge ($/kWh)	**$ 0.035550**		**$ 0.035727**	**$ 0.035727**	**$ 0.035727**	**$ 0.035727**	**$ 0.034917**	**$ 0.034917**	**$ 0.034917**	**$ 0.034472**
73											
74	**Total Production**	$ 801,730,829		$ 294,321,277	$ 26,908,435	$ 69,356,393	$ 272,550,915	$ 24,265,055	$ 43,479,393	$ 53,353,498	$ 13,157,321
75											
76											
77	**Transmission**										
78	**Demand**										
79	On-Peak	$ 65,915,251		$ 24,909,876	$ 2,376,967	$ 6,488,552	$ 23,271,767	$ 1,804,147	$ 2,864,866	$ 3,371,416	$ 814,868
80	Annual	-		-	-	-	-	-	-	-	-
81	Total Demand	$ 65,915,251		$ 24,909,876	$ 2,376,967	$ 6,488,552	$ 23,271,767	$ 1,804,147	$ 2,864,866	$ 3,371,416	$ 814,868
82											
83	**Pass-Throughs**										
84	Regulatory On-Peak	$ 65,915,251		$ 24,909,876	$ 2,376,967	$ 6,488,552	$ 23,271,767	$ 1,804,147	$ 2,864,866	$ 3,371,416	$ 814,868
85	Regulatory Annual	-		-	-	-	-	-	-	-	-
86	Total Pass-Throughs	$ 65,915,251		$ 24,909,876	$ 2,376,967	$ 6,488,552	$ 23,271,767	$ 1,804,147	$ 2,864,866	$ 3,371,416	$ 814,868
87											
88	**Net Recovered from Base Rates**										
89	On-Peak	$ 0		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	Annual	-		-	-	-	-	-	-	-	-
91	Total Net Recovered from Base Rates	$ 0		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92											
93	*On-Peak (June - September)*	$ 0		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
94	Summer Billed Demand	14,807,767	Sum Max Demands - S	8,152,718	385,302	1,110,031	3,710,473	344,768	411,092	483,896	139,911
95	Summer Demand Charge Adder ($/kW)	$ 0.00		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96	Summer Billed Energy	4,838,733,296	kWh Sold - S	1,832,044,412	144,102,118	385,685,698	1,598,520,610	157,106,615	277,985,057	338,135,114	87,377,150
97	Summer Energy Charge Adder ($/kWh)	$ 0.000000		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
98											
99	*All Months*	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
100	Annual Billed Demand	41,358,581	Sum Max Demands	22,668,750	1,155,332	3,000,305	10,370,350	935,115	1,195,446	1,431,533	408,622
101	Annual Demand Charge ($/kW)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
102	Annual Billed Energy	11,813,938,683	kWh Sold	3,864,401,370	378,885,207	987,036,795	4,142,609,008	405,947,626	769,829,965	968,264,949	247,619,682
103	Annual Energy Charge ($/kWh)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
104											
105	*Transmission Demand Related Summary*										
106	On-Peak Demand Charge ($/kW)	**$ 0.00**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
107	Off-Peak Demand Charge ($/kW)	**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
108	On-Peak Demand Charge ($/kWh)	**$ 0.000000**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
109	Off-Peak Demand Charge ($/kWh)	**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
110											
111	**Total Transmission**	$ 65,915,251		$ 24,909,876	$ 2,376,967	$ 6,488,552	$ 23,271,767	$ 1,804,147	$ 2,864,866	$ 3,371,416	$ 814,868
112											
113											

Test Year Cost of Service for Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW	Primary Voltage ≥ 20 MW	Transmission Voltage
A		B	C	D	E	F	G	H	I	J	K
114	**Distribution**										
115	**Demand**										
116	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
117	Annual	145,509,111		61,808,222	6,062,801	13,923,583	50,508,233	2,535,450	4,399,710	5,189,845	-
118	Total Demand	$ 145,509,111		$ 61,808,222	$ 6,062,801	$ 13,923,583	$ 50,508,233	$ 2,535,450	$ 4,399,710	$ 5,189,845	$ -
119											
120	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
121	Summer Billed Demand	14,807,767	Sum Max Demands - S	8,152,718	385,302	1,110,031	3,710,473	344,768	411,092	483,896	139,911
122	Summer Demand Charge Adder ($/kW)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
123	Summer Billed Energy	4,838,733,296	kWh Sold - S	1,832,044,412	144,102,118	385,685,698	1,598,520,610	157,106,615	277,985,057	338,135,114	87,377,150
124	Summer Energy Charge Adder ($/kWh)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
125	Summer Customer Months	1,641,080	No. Cust Mo. - S	1,458,084	128,003	41,440	12,855	408	80	16	16
126	Summer Customer Charge ($/Cust-Month)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
127											
128	*All Months*	$ 145,509,111		$ 61,808,222	$ 6,062,801	$ 13,923,583	$ 50,508,233	$ 2,535,450	$ 4,399,710	$ 5,189,845	$ -
129	Annual Billed Demand	41,358,581	Sum Max Demands	22,668,750	1,155,332	3,000,305	10,370,350	935,115	1,195,446	1,431,533	408,622
130	Annual Demand Charge ($/kW)	$ 3.52		$ 2.73	$ 5.25	$ 4.64	$ 4.87	$ 2.71	$ 3.68	$ 3.63	$ -
131	Annual Billed Energy	11,813,938,683	kWh Sold	3,864,401,370	378,885,207	987,036,795	4,142,609,008	405,947,626	769,829,965	968,264,949	247,619,682
132	Annual Energy Charge ($/kWh)	$ 0.012317		$ 0.015994	$ 0.016002	$ 0.014106	$ 0.012192	$ 0.006246	$ 0.005715	$ 0.005360	$ -
133	Annual Customer Months	4,923,240	No. Cust Mo.	4,374,252	384,008	124,321	38,566	1,224	240	48	48
134	Annual Customer Charge ($/Cust-Month)	$ 29.56		$ 14.13	$ 15.79	$ 112.00	$ 1,309.64	$ 2,071.45	$ 18,332.12	$ 108,121.78	$ -
135											
136	*Distribution Demand Related Summary*										
137	On-Peak Demand Charge ($/kW)	**$ 3.52**		**$ 2.73**	**$ 5.25**	**$ 4.64**	**$ 4.87**	**$ 2.71**	**$ 3.68**	**$ 3.63**	**$ -**
138	Off-Peak Demand Charge ($/kW)	**$ 3.52**		**$ 2.73**	**$ 5.25**	**$ 4.64**	**$ 4.87**	**$ 2.71**	**$ 3.68**	**$ 3.63**	**$ -**
139	On-Peak Demand Charge ($/kWh)	**$ 0.012317**		**$ 0.015994**	**$ 0.016002**	**$ 0.014106**	**$ 0.012192**	**$ 0.006246**	**$ 0.005715**	**$ 0.005360**	**$ -**
140	Off-Peak Demand Charge ($/kWh)	**$ 0.012317**		**$ 0.015994**	**$ 0.016002**	**$ 0.014106**	**$ 0.012192**	**$ 0.006246**	**$ 0.005715**	**$ 0.005360**	**$ -**
141	On-Peak Customer Charge ($/Cust-Month)	**$ 29.56**		**$ 14.13**	**$ 15.79**	**$ 112.00**	**$ 1,309.64**	**$ 2,071.45**	**$ 18,332.12**	**$ 108,121.78**	**$ -**
142	Off-Peak Customer Charge ($/Cust-Month)	**$ 29.56**		**$ 14.13**	**$ 15.79**	**$ 112.00**	**$ 1,309.64**	**$ 2,071.45**	**$ 18,332.12**	**$ 108,121.78**	**$ -**
143											
144	**Customer**										
145	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
146	Annual	17,108,086		12,294,881	3,122,725	1,010,968	526,713	87,361	17,130	3,530	43,450
147	Total Customer	$ 17,108,086		$ 12,294,881	$ 3,122,725	$ 1,010,968	$ 526,713	$ 87,361	$ 17,130	$ 3,530	$ 43,450
148											
149	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
150											
151											
152	Summer Customer Months	1,641,080	No. Cust Mo. - S	1,458,084	128,003	41,440	12,855	408	80	16	16
153	Summer Customer Charge Adder ($/Cust-Mo	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
154											
155	*All Months*	$ 17,108,086		$ 12,294,881	$ 3,122,725	$ 1,010,968	$ 526,713	$ 87,361	$ 17,130	$ 3,530	$ 43,450
156											
157											
158	Annual Customer Months	4,923,240	No. Cust Mo.	4,374,252	384,008	124,321	38,566	1,224	240	48	48
159	Annual Customer Charge ($/Cust-Month)	$ 3.47		$ 2.81	$ 8.13	$ 8.13	$ 13.66	$ 71.37	$ 71.37	$ 73.54	$ 905.20
160											
161	*Distribution Customer Related Summary*										
162											
163											
164	On-Peak Customer Charge ($/Cust-Month)	**$ 3.47**		**$ 2.81**	**$ 8.13**	**$ 8.13**	**$ 13.66**	**$ 71.37**	**$ 71.37**	**$ 73.54**	**$ 905.20**
165	Off-Peak Customer Charge ($/Cust-Month)	**$ 3.47**		**$ 2.81**	**$ 8.13**	**$ 8.13**	**$ 13.66**	**$ 71.37**	**$ 71.37**	**$ 73.54**	**$ 905.20**
166											
167	**Lighting**										
168	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
169	Annual	9,835,657		-	-	-	-	-	-	-	-
170	Total Lighting	$ 9,835,657		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Test Year Cost of Service for Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW	Primary Voltage ≥ 20 MW	Transmission Voltage
A		B	C	D	E	F	G	H	I	J	K
171											
172	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
173											
174											
175	Summer City-Owned Bulb Count	234,484	City-Owned Bulb-Mo. - S	-	-	-	-	-	-	-	-
176	Summer Bulb Charge Adder ($/Bulb-Month)	$ -									
177											
178	*All Months*	$ 9,835,657		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
179											
180											
181	Annual City-Owned Bulb Count	703,452	City-Owned Bulb-Mo.	-	-	-	-	-	-	-	-
182	Annual Bulb Charge ($/Bulb-Month)	$ 13.98									
183											
184	*Distribution Lighting Direct Summary*										
185											
186											
187	On-Peak Lighting Charge ($/Bulb-Month)	**$ 13.98**									
188	Off-Peak Lighting Charge ($/Bulb-Month)	**$ 13.98**									
189											
190	**Total Distribution**	$ 172,452,854		$ 74,103,103	$ 9,185,526	$ 14,934,551	$ 51,034,946	$ 2,622,811	$ 4,416,839	$ 5,193,375	$ 43,450
191											
192											
193	**Customer**										
194	**Customer**										
195	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
196	Annual	95,921,868		82,589,419	7,541,285	2,780,004	2,126,162	229,781	468,281	128,857	48,855
197	Total Customer	$ 95,921,868		$ 82,589,419	$ 7,541,285	$ 2,780,004	$ 2,126,162	$ 229,781	$ 468,281	$ 128,857	$ 48,855
198											
199	**Pass-Throughs**										
200	Regulatory On-Peak	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
201	Regulatory Annual	-		-	-	-	-	-	-	-	-
202	Community Benefit On-Peak	-		-	-	-	-	-	-	-	-
203	Community Benefit Annual	-		-	-	-	-	-	-	-	-
204	Total Pass-Throughs	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
205											
206	**Net Recovered from Base Rates**										
207	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
208	Annual	95,921,868		82,589,419	7,541,285	2,780,004	2,126,162	229,781	468,281	128,857	48,855
209	Total Net Recovered from Base Rates	$ 95,921,868		$ 82,589,419	$ 7,541,285	$ 2,780,004	$ 2,126,162	$ 229,781	$ 468,281	$ 128,857	$ 48,855
210											
211	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
212											
213											
214	Summer Customer Months	1,641,080	No. Cust Mo. - S	1,458,084	128,003	41,440	12,855	408	80	16	16
215	Summer Customer Charge Adder ($/Cust-Mo	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
216											
217	*All Months*	$ 95,921,868		$ 82,589,419	$ 7,541,285	$ 2,780,004	$ 2,126,162	$ 229,781	$ 468,281	$ 128,857	$ 48,855
218											
219											
220	Annual Customer Months	4,923,240	No. Cust Mo.	4,374,252	384,008	124,321	38,566	1,224	240	48	48
221	Annual Customer Charge ($/Cust-Month)	$ 19.48		$ 18.88	$ 19.64	$ 22.36	$ 55.13	$ 187.73	$ 1,951.17	$ 2,684.52	$ 1,017.82
222											
223	*Customer Customer Related Summary*										
224											
225											
226	On-Peak Customer Charge ($/Cust-Month)	**$ 19.48**		**$ 18.88**	**$ 19.64**	**$ 22.36**	**$ 55.13**	**$ 187.73**	**$ 1,951.17**	**$ 2,684.52**	**$ 1,017.82**
227	Off-Peak Customer Charge ($/Cust-Month)	**$ 19.48**		**$ 18.88**	**$ 19.64**	**$ 22.36**	**$ 55.13**	**$ 187.73**	**$ 1,951.17**	**$ 2,684.52**	**$ 1,017.82**

Test Year Cost of Service for Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW	Primary Voltage ≥ 20 MW	Transmission Voltage
A		B	C	D	E	F	G	H	I	J	K
228											
229	**Total Customer**	$ 95,921,868		$ 82,589,419	$ 7,541,285	$ 2,780,004	$ 2,126,162	$ 229,781	$ 468,281	$ 128,857	$ 48,855
230											
231											
232	**Adders**										
233	**City-Owned (Service Area) Street Lighting**										
234	**Adder**										
235	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
236	Annual	-		4,411,919	426,544	867,318	3,235,158	268,112	474,908	575,191	130,381
237	Total Adder	$ -		$ 4,411,919	$ 426,544	$ 867,318	$ 3,235,158	$ 268,112	$ 474,908	$ 575,191	$ 130,381
238											
239	**Recovered from Pass-Through**										
240	Community Benefit On-Peak	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
241	Community Benefit Annual	10,434,438		4,411,919	426,544	867,318	3,235,158	268,112	474,908	575,191	130,381
242	Total Recovered from Pass-Through	$ 10,434,438		$ 4,411,919	$ 426,544	$ 867,318	$ 3,235,158	$ 268,112	$ 474,908	$ 575,191	$ 130,381
243											
244	**Net Recovered from Base Rates**										
245	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
246	Annual	(10,434,438)		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
247	Total Net Recovered from Base Rates	$ (10,434,438)		$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
248											
249	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
250	Summer Billed Demand	14,807,767	Sum Max Demands - S	8,152,718	385,302	1,110,031	3,710,473	344,768	411,092	483,896	139,911
251	Summer Demand Charge Adder ($/kW)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
252	Summer Billed Energy	4,838,733,296	kWh Sold - S	1,832,044,412	144,102,118	385,685,698	1,598,520,610	157,106,615	277,985,057	338,135,114	87,377,150
253	Summer Energy Charge Adder ($/kWh)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
254											
255	*All Months*	$ (10,434,438)		$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
256	Annual Billed Demand	41,358,581	Sum Max Demands	22,668,750	1,155,332	3,000,305	10,370,350	935,115	1,195,446	1,431,533	408,622
257	Annual Demand Charge ($/kW)	$ (0.25)		$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)
258	Annual Billed Energy	11,813,938,683	kWh Sold	3,864,401,370	378,885,207	987,036,795	4,142,609,008	405,947,626	769,829,965	968,264,949	247,619,682
259	Annual Energy Charge ($/kWh)	$ (0.000883)		$ (0.000000)	$ (0.000000)	$ (0.000000)	$ (0.000000)	$ (0.000000)	$ (0.000000)	$ (0.000000)	$ (0.000000)
260											
261	*City-Owned (Service Area) Street Lighting Summary*										
262	On-Peak Adder ($/kW)	**$ (0.25)**		**$ (0.00)**	**$ (0.00)**	**$ (0.00)**	**$ (0.00)**	**$ (0.00)**	**$ (0.00)**	**$ (0.00)**	**$ (0.00)**
263	Off-Peak Adder ($/kW)	**$ (0.25)**		**$ (0.00)**	**$ (0.00)**	**$ (0.00)**	**$ (0.00)**	**$ (0.00)**	**$ (0.00)**	**$ (0.00)**	**$ (0.00)**
264	On-Peak Adder ($/kWh)	**$ (0.000883)**		**$ (0.000000)**	**$ (0.000000)**	**$ (0.000000)**	**$ (0.000000)**	**$ (0.000000)**	**$ (0.000000)**	**$ (0.000000)**	**$ (0.000000)**
265	Off-Peak Adder ($/kWh)	**$ (0.000883)**		**$ (0.000000)**	**$ (0.000000)**	**$ (0.000000)**	**$ (0.000000)**	**$ (0.000000)**	**$ (0.000000)**	**$ (0.000000)**	**$ (0.000000)**
266											
267	**Total City-Owned (Service Area) Street Lighting**	$ -		$ 4,411,919	$ 426,544	$ 867,318	$ 3,235,158	$ 268,112	$ 474,908	$ 575,191	$ 130,381
268											
269											
270	**Pass-Throughs**										
271	**Energy Adjustment**										
272	**Pass-Through**										
273	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
274	Annual	-		-	-	-	-	-	-	-	-
275	Total Pass-Through	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
276											
277	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
278											
279											
280	Summer Billed Energy	4,731,673,910	kWh Sold Net GC - S	1,805,682,692	140,314,009	374,211,490	1,536,289,184	153,902,693	277,985,057	338,135,114	87,377,150
281	Summer Energy Adjustment Adder ($/kWh)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
282											
283	*All Months*	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Test Year Cost of Service for Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW	Primary Voltage ≥ 20 MW	Transmission Voltage
A		B	C	D	E	F	G	H	I	J	K
284											
285											
286	Annual Billed Energy	11,561,258,164	kWh Sold Net GC	3,809,639,019	369,615,649	959,408,628	3,990,550,730	397,013,654	769,829,965	968,264,949	247,619,682
287	Annual Energy Adjustment ($/kWh)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
288											
289	*Energy Adjustment Summary*										
290											
291											
292	On-Peak Energy Adjustment ($/kWh)	**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
293	Off-Peak Energy Adjustment ($/kWh)	**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
294											
295	**Total Energy Adjustment**	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
296											
297											
298	**Regulatory**										
299	**Pass-Through**										
300	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
301	Annual	75,755,050		28,168,347	2,693,107	7,309,156	26,684,976	2,136,029	3,508,401	4,180,832	1,019,226
302	Total Pass-Through	$ 75,755,050		$ 28,168,347	$ 2,693,107	$ 7,309,156	$ 26,684,976	$ 2,136,029	$ 3,508,401	$ 4,180,832	$ 1,019,226
303											
304	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
305	Summer Billed Demand	14,807,767	Sum Max Demands - S	8,152,718	385,302	1,110,031	3,710,473	344,768	411,092	483,896	139,911
306	Summer Demand Charge Adder ($/kW)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
307	Summer Billed Energy	4,838,733,296	kWh Sold - S	1,832,044,412	144,102,118	385,685,698	1,598,520,610	157,106,615	277,985,057	338,135,114	87,377,150
308	Summer Energy Charge Adder ($/kWh)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
309											
310	*All Months*	$ 75,755,050		$ 28,168,347	$ 2,693,107	$ 7,309,156	$ 26,684,976	$ 2,136,029	$ 3,508,401	$ 4,180,832	$ 1,019,226
311	Annual Billed Demand	41,358,581	Sum Max Demands	22,668,750	1,155,332	3,000,305	10,370,350	935,115	1,195,446	1,431,533	408,622
312	Annual Demand Charge ($/kW)	$ 1.83		$ 1.24	$ 2.33	$ 2.44	$ 2.57	$ 2.28	$ 2.93	$ 2.92	$ 2.49
313	Annual Billed Energy	11,813,938,683	kWh Sold	3,864,401,370	378,885,207	987,036,795	4,142,609,008	405,947,626	769,829,965	968,264,949	247,619,682
314	Annual Energy Charge ($/kWh)	$ 0.006412		$ 0.007289	$ 0.007108	$ 0.007405	$ 0.006442	$ 0.005262	$ 0.004557	$ 0.004318	$ 0.004116
315											
316	*Regulatory Summary*										
317	On-Peak Regulatory Charge ($/kW)	**$ 1.83**		**$ 1.24**	**$ 2.33**	**$ 2.44**	**$ 2.57**	**$ 2.28**	**$ 2.93**	**$ 2.92**	**$ 2.49**
318	Off-Peak Regulatory Charge ($/kW)	**$ 1.83**		**$ 1.24**	**$ 2.33**	**$ 2.44**	**$ 2.57**	**$ 2.28**	**$ 2.93**	**$ 2.92**	**$ 2.49**
319	On-Peak Regulatory Charge ($/kWh)	**$ 0.006412**		**$ 0.007289**	**$ 0.007108**	**$ 0.007405**	**$ 0.006442**	**$ 0.005262**	**$ 0.004557**	**$ 0.004318**	**$ 0.004116**
320	Off-Peak Regulatory Charge ($/kWh)	**$ 0.006412**		**$ 0.007289**	**$ 0.007108**	**$ 0.007405**	**$ 0.006442**	**$ 0.005262**	**$ 0.004557**	**$ 0.004318**	**$ 0.004116**
321											
322	**Total Regulatory**	$ 75,755,050		$ 28,168,347	$ 2,693,107	$ 7,309,156	$ 26,684,976	$ 2,136,029	$ 3,508,401	$ 4,180,832	$ 1,019,226
323											
324											
325	**Community Benefit --- City-Owned (Service Area) Street Lighting**										
326	**Pass-Through**										
327	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
328	Annual	10,434,438		4,411,919	426,544	867,318	3,235,158	268,112	474,908	575,191	130,381
329	Total Pass-Through	$ 10,434,438		$ 4,411,919	$ 426,544	$ 867,318	$ 3,235,158	$ 268,112	$ 474,908	$ 575,191	$ 130,381
330											
331	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
332	Summer Billed Demand	14,807,767	Sum Max Demands - S	8,152,718	385,302	1,110,031	3,710,473	344,768	411,092	483,896	139,911
333	Summer Demand Charge Adder ($/kW)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
334	Summer Billed Energy	4,838,733,296	kWh Sold - S	1,832,044,412	144,102,118	385,685,698	1,598,520,610	157,106,615	277,985,057	338,135,114	87,377,150
335	Summer Energy Charge Adder ($/kWh)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
336											
337	*All Months*	$ 10,434,438		$ 4,411,919	$ 426,544	$ 867,318	$ 3,235,158	$ 268,112	$ 474,908	$ 575,191	$ 130,381
338	Annual Billed Demand	41,358,581	Sum Max Demands	22,668,750	1,155,332	3,000,305	10,370,350	935,115	1,195,446	1,431,533	408,622
339	Annual Demand Charge ($/kW)	$ 0.25		$ 0.19	$ 0.37	$ 0.29	$ 0.31	$ 0.29	$ 0.40	$ 0.40	$ 0.32
340	Annual Billed Energy	11,813,938,683	kWh Sold	3,864,401,370	378,885,207	987,036,795	4,142,609,008	405,947,626	769,829,965	968,264,949	247,619,682

Test Year Cost of Service for Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW	Primary Voltage ≥ 20 MW	Transmission Voltage
A		B	C	D	E	F	G	H	I	J	K
341	Annual Energy Charge ($/kWh)	$ 0.000883		$ 0.001142	$ 0.001126	$ 0.000879	$ 0.000781	$ 0.000660	$ 0.000617	$ 0.000594	$ 0.000527
342											
343	*Community Benefit --- City-Owned (Service Area) Street Lighting Summary*										
344	On-Peak Community Benefit ($/kW)	**$ 0.25**		**$ 0.19**	**$ 0.37**	**$ 0.29**	**$ 0.31**	**$ 0.29**	**$ 0.40**	**$ 0.40**	**$ 0.32**
345	Off-Peak Community Benefit ($/kW)	**$ 0.25**		**$ 0.19**	**$ 0.37**	**$ 0.29**	**$ 0.31**	**$ 0.29**	**$ 0.40**	**$ 0.40**	**$ 0.32**
346	On-Peak Community Benefit ($/kWh)	**$ 0.000883**		**$ 0.001142**	**$ 0.001126**	**$ 0.000879**	**$ 0.000781**	**$ 0.000660**	**$ 0.000617**	**$ 0.000594**	**$ 0.000527**
347	Off-Peak Community Benefit ($/kWh)	**$ 0.000883**		**$ 0.001142**	**$ 0.001126**	**$ 0.000879**	**$ 0.000781**	**$ 0.000660**	**$ 0.000617**	**$ 0.000594**	**$ 0.000527**
348											
349	**Community Benefit --- Energy Efficiency**										
350	**Pass-Through**										
351	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
352	Annual	27,720,129		11,613,049	1,122,747	2,282,952	8,515,580	705,723	1,250,052	1,514,017	343,189
353	Total Pass-Through	$ 27,720,129		$ 11,613,049	$ 1,122,747	$ 2,282,952	$ 8,515,580	$ 705,723	$ 1,250,052	$ 1,514,017	$ 343,189
354											
355	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
356	Summer Billed Demand	14,807,767	Sum Max Demands - S	8,152,718	385,302	1,110,031	3,710,473	344,768	411,092	483,896	139,911
357	Summer Demand Charge Adder ($/kW)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
358	Summer Billed Energy	4,838,733,296	kWh Sold - S	1,832,044,412	144,102,118	385,685,698	1,598,520,610	157,106,615	277,985,057	338,135,114	87,377,150
359	Summer Energy Charge Adder ($/kWh)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
360											
361	*All Months*	$ 27,720,129		$ 11,613,049	$ 1,122,747	$ 2,282,952	$ 8,515,580	$ 705,723	$ 1,250,052	$ 1,514,017	$ 343,189
362	Annual Billed Demand	41,358,581	Sum Max Demands	22,668,750	1,155,332	3,000,305	10,370,350	935,115	1,195,446	1,431,533	408,622
363	Annual Demand Charge ($/kW)	$ 0.67		$ 0.51	$ 0.97	$ 0.76	$ 0.82	$ 0.75	$ 1.05	$ 1.06	$ 0.84
364	Annual Billed Energy	11,813,938,683	kWh Sold	3,864,401,370	378,885,207	987,036,795	4,142,609,008	405,947,626	769,829,965	968,264,949	247,619,682
365	Annual Energy Charge ($/kWh)	$ 0.002346		$ 0.003005	$ 0.002963	$ 0.002313	$ 0.002056	$ 0.001738	$ 0.001624	$ 0.001564	$ 0.001386
366											
367	*Community Benefit --- Energy Efficiency Summary*										
368	On-Peak Community Benefit ($/kW)	**$ 0.67**		**$ 0.51**	**$ 0.97**	**$ 0.76**	**$ 0.82**	**$ 0.75**	**$ 1.05**	**$ 1.06**	**$ 0.84**
369	Off-Peak Community Benefit ($/kW)	**$ 0.67**		**$ 0.51**	**$ 0.97**	**$ 0.76**	**$ 0.82**	**$ 0.75**	**$ 1.05**	**$ 1.06**	**$ 0.84**
370	On-Peak Community Benefit ($/kWh)	**$ 0.002346**		**$ 0.003005**	**$ 0.002963**	**$ 0.002313**	**$ 0.002056**	**$ 0.001738**	**$ 0.001624**	**$ 0.001564**	**$ 0.001386**
371	Off-Peak Community Benefit ($/kWh)	**$ 0.002346**		**$ 0.003005**	**$ 0.002963**	**$ 0.002313**	**$ 0.002056**	**$ 0.001738**	**$ 0.001624**	**$ 0.001564**	**$ 0.001386**
372											
373	**Total Community Benefit**	$ 38,154,567		$ 16,024,969	$ 1,549,291	$ 3,150,270	$ 11,750,738	$ 973,834	$ 1,724,960	$ 2,089,208	$ 473,570
374											
375											
376											
377	**Total Base Rate Unit Costs**										
378	**On-Peak (June - Sept)**										
379	Customer-Related										
380	$/Cust-Month			$ 21.69	$ 27.77	$ 30.49	$ 68.79	$ 259.10	$ 2,022.55	$ 2,758.06	$ 1,923.02
381	Demand-Related										
382	Production & Transmission										
383	$/kW			$ 6.44	$ 10.77	$ 10.65	$ 11.18	$ 9.93	$ 12.62	$ 12.34	$ 10.17
384	$/kWh										
385	Distribution (wires)										
386	$/kW				$ 5.25	$ 4.64	$ 4.87	$ 2.71	$ 3.68	$ 3.63	$ -
387	$/kWh										
388	$/Cust-Month			$ 14.13							
389	$/Bulb-Month										
390	Adder										
391	$/kW					$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)
392	$/kWh			$ (0.000000)	$ (0.000000)						
393	Energy-Related										
394	$/kWh			$ 0.038177	$ 0.038177	$ 0.038177	$ 0.038177	$ 0.037313	$ 0.037313	$ 0.037313	$ 0.036837
395											

Test Year Cost of Service for Rate Design
Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW	Primary Voltage ≥ 20 MW	Transmission Voltage
A		B	C	D	E	F	G	H	I	J	K
396	**Off-Peak**										
397	Customer-Related										
398	$/Cust-Month			$ 21.69	$ 27.77	$ 30.49	$ 68.79	$ 259.10	$ 2,022.55	$ 2,758.06	$ 1,923.02
399	Demand-Related										
400	Production & Transmission										
401	$/kW			$ 5.79	$ 9.60	$ 9.60	$ 10.04	$ 8.94	$ 11.29	$ 11.02	$ 9.09
402	$/kWh										
403	Distribution (wires)										
404	$/kW				$ 5.25	$ 4.64	$ 4.87	$ 2.71	$ 3.68	$ 3.63	$ -
405	$/kWh										
406	$/Cust-Month			$ 14.13							
407	$/Bulb-Month										
408	Adder										
409	$/kW					$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)
410	$/kWh			$ (0.000000)	$ (0.000000)						
411	Energy-Related										
412	$/kWh			$ 0.035727	$ 0.035727	$ 0.035727	$ 0.035727	$ 0.034917	$ 0.034917	$ 0.034917	$ 0.034472
413											
414	**Total Pass-Through Unit Costs**										
415	**On-Peak (June - Sept)**										
416	Demand-Related										
417	**Regulatory**										
418	$/kW				$ 2.33	$ 2.44	$ 2.57	$ 2.28	$ 2.93	$ 2.92	$ 2.49
419	$/kWh			$ 0.007289							
420											
421	**Community Benefit --- City-Owned (Service Area) Street Lighting**										
422	$/kW										
423	$/kWh			$ 0.001142	$ 0.001126	$ 0.000879	$ 0.000781	$ 0.000660	$ 0.000617	$ 0.000594	$ 0.000527
424											
425	**Community Benefit --- Energy Efficiency**										
426	$/kW										
427	$/kWh			$ 0.003005	$ 0.002963	$ 0.002313	$ 0.002056	$ 0.001738	$ 0.001624	$ 0.001564	$ 0.001386
428											
429	Energy-Related										
430	**Energy Adjustment**										
431	$/kWh			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
432											
433	**Off-Peak**										
434	Demand-Related										
435	**Regulatory**										
436	$/kW				$ 2.33	$ 2.44	$ 2.57	$ 2.28	$ 2.93	$ 2.92	$ 2.49
437	$/kWh			$ 0.007289							
438											
439	**Community Benefit --- City-Owned (Service Area) Street Lighting**										
440	$/kW										
441	$/kWh			$ 0.001142	$ 0.001126	$ 0.000879	$ 0.000781	$ 0.000660	$ 0.000617	$ 0.000594	$ 0.000527
442											
443	**Community Benefit --- Energy Efficiency**										
444	$/kW										
445	$/kWh			$ 0.003005	$ 0.002963	$ 0.002313	$ 0.002056	$ 0.001738	$ 0.001624	$ 0.001564	$ 0.001386
446											
447	Energy-Related										
448	**Energy Adjustment**										
449	$/kWh			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
450											

Test Year Cost of Service for Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A		B	C	L	M	N	O	P
1	**Unbundled Cost Summary - Base Rates**							
2	**COST OF SERVICE SUMMARY**							
3	Production							
4	**Demand**							
5	On-Peak	$ 12,952,332		$ 42,451	$ 20,052	$ 2,818	$ 17,384	$ 12,952,332
6	Annual	356,169,696		1,325,971	596,474	75,044	451,948	356,169,696
7	Total Demand	$ 369,122,028		$ 1,368,421	$ 616,526	$ 77,862	$ 469,332	$ 369,122,028
8								
9	**Pass-Throughs**							
10	Regulatory On-Peak	$ -		$ -	$ -	$ -	$ -	$ -
11	Regulatory Annual	9,839,798		27,125	9,891	1,459	3,705	9,839,798
12	Community Benefit On-Peak	-		-	-	-	-	-
13	Community Benefit Annual	27,720,129		254,612	93,335	4,262	20,611	27,720,129
14	Total Pass-Throughs	$ 37,559,927		$ 281,737	$ 103,226	$ 5,721	$ 24,316	$ 37,559,927
15								
16	**Net Recovered from Base Rates**							
17	On-Peak	$ 12,952,332		$ 42,451	$ 20,052	$ 2,818	$ 17,384	$ 12,952,332
18	Annual	318,609,769		1,044,234	493,248	69,323	427,632	318,609,769
19	Total Net Recovered from Base Rates	$ 331,562,101		$ 1,086,685	$ 513,300	$ 72,141	$ 445,016	$ 331,562,101
20								
21	*On-Peak (June - September)*	$ 12,952,332		$ 42,451	$ 20,052	$ 2,818	$ 17,384	
22	Summer Billed Demand	14,807,767	Sum Max Demands - S	46,775	14,921	2,226	5,654	14,807,767
23	Summer Demand Charge Adder ($/kW)	$ 0.87		$ 0.91	$ 1.34	$ 1.27	$ 3.07	
24	Summer Billed Energy	4,838,733,296	kWh Sold - S	11,950,939	3,812,307	568,668	1,444,608	4,838,733,296
25	Summer Energy Charge Adder ($/kWh)	$ 0.002677		$ 0.003552	$ 0.005260	$ 0.004956	$ 0.012034	
26								
27	*All Months*	$ 318,609,769		$ 1,044,234	$ 493,248	$ 69,323	$ 427,632	
28	Annual Billed Demand	41,358,581	Sum Max Demands	124,124	45,263	6,677	17,064	41,358,581
29	Annual Demand Charge ($/kW)	$ 7.70		$ 8.41	$ 10.90	$ 10.38	$ 25.06	
30	Annual Billed Energy	11,813,938,683	kWh Sold	31,713,621	11,564,634	1,706,004	4,359,820	11,813,938,683
31	Annual Energy Charge ($/kWh)	$ 0.026969		$ 0.032927	$ 0.042651	$ 0.040635	$ 0.098085	
32								
33	*Production Demand Related Summary*							
34	On-Peak Demand Charge ($/kW)	**$ 8.58**		**$ 9.32**	**$ 12.24**	**$ 11.65**	**$ 28.14**	
35	Off-Peak Demand Charge ($/kW)	**$ 7.70**		**$ 8.41**	**$ 10.90**	**$ 10.38**	**$ 25.06**	
36	On-Peak Demand Charge ($/kWh)	**$ 0.029646**		**$ 0.036479**	**$ 0.047911**	**$ 0.045591**	**$ 0.110119**	
37	Off-Peak Demand Charge ($/kWh)	**$ 0.026969**		**$ 0.032927**	**$ 0.042651**	**$ 0.040635**	**$ 0.098085**	
38								
39	**Energy**							
40	On-Peak	$ 11,546,911		$ 29,291	$ 9,344	$ 1,394	$ 3,541	$ 11,546,911
41	Annual	421,061,891		1,133,018	413,164	60,950	155,700	421,061,891
42	Total Energy	$ 432,608,801		$ 1,162,309	$ 422,508	$ 62,343	$ 159,240	$ 432,608,801
43								
44	**Pass-Throughs**							
45	Energy Adjustment On-Peak	$ -		$ -	$ -	$ -	$ -	$ -
46	Energy Adjustment Annual	-		-	-	-	-	-
47	Green Choice On-Peak	-		-	-	-	-	-
48	Green Choice Annual	10,057,082		-	-	-	946	10,057,082
49	Total Pass-Throughs	$ 10,057,082		$ -	$ -	$ -	$ 946	$ 10,057,082
50								
51	**Net Recovered from Base Rates**							
52	On-Peak	$ 11,546,911		$ 29,291	$ 9,344	$ 1,394	$ 3,541	$ 11,546,911
53	Annual	411,004,809		1,133,018	413,164	60,950	154,754	411,004,809
54	Total Net Recovered from Base Rates	$ 422,551,719		$ 1,162,309	$ 422,508	$ 62,343	$ 158,295	$ 422,551,719
55								
56	*On-Peak (June - September)*	$ 11,546,911		$ 29,291	$ 9,344	$ 1,394	$ 3,541	
57								

Test Year Cost of Service for Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A		B	C	L	M	N	O	P
58								
59	Summer Billed Energy	4,731,673,910	kWh Sold Net GC - S	11,950,939	3,812,307	568,668	1,444,608	4,731,673,910
60	Summer Energy Charge Adder ($/kWh)	$ 0.002440		$ 0.002451	$ 0.002451	$ 0.002451	$ 0.002451	
61								
62	*All Months*	$ 411,004,809		$ 1,133,018	$ 413,164	$ 60,950	$ 154,754	
63								
64								
65	Annual Billed Energy	11,561,258,164	kWh Sold Net GC	31,713,621	11,564,634	1,706,004	4,331,628	11,561,258,164
66	Annual Energy Charge ($/kWh)	$ 0.035550		$ 0.035727	$ 0.035727	$ 0.035727	$ 0.035727	
67								
68	*Production Energy Related Summary*							
69								
70								
71	On-Peak Energy Charge ($/kWh)	**$ 0.037991**		**$ 0.038177**	**$ 0.038177**	**$ 0.038177**	**$ 0.038177**	
72	Off-Peak Energy Charge ($/kWh)	**$ 0.035550**		**$ 0.035727**	**$ 0.035727**	**$ 0.035727**	**$ 0.035727**	
73								
74	**Total Production**	$ 801,730,829		$ 2,530,730	$ 1,039,034	$ 140,206	$ 628,573	$ 801,730,829
75								
76								
77	**Transmission**							
78	**Demand**							
79	On-Peak	$ 65,915,251		$ 2,478	$ -	$ 169	$ 10,147	$ 65,915,251
80	Annual	-		-	-	-	-	-
81	Total Demand	$ 65,915,251		$ 2,478	$ -	$ 169	$ 10,147	$ 65,915,251
82								
83	**Pass-Throughs**							
84	Regulatory On-Peak	$ 65,915,251		$ 2,478	$ -	$ 169	$ 10,147	$ 65,915,251
85	Regulatory Annual	-		-	-	-	-	-
86	Total Pass-Throughs	$ 65,915,251		$ 2,478	$ -	$ 169	$ 10,147	$ 65,915,251
87								
88	**Net Recovered from Base Rates**							
89	On-Peak	$ 0		$ -	$ -	$ -	$ -	$ -
90	Annual	-		-	-	-	-	-
91	Total Net Recovered from Base Rates	$ 0		$ -	$ -	$ -	$ -	$ -
92								
93	*On-Peak (June - September)*	$ 0		$ -	$ -	$ -	$ -	
94	Summer Billed Demand	14,807,767	Sum Max Demands - S	46,775	14,921	2,226	5,654	14,807,767
95	Summer Demand Charge Adder ($/kW)	$ 0.00		$ -	$ -	$ -	$ -	
96	Summer Billed Energy	4,838,733,296	kWh Sold - S	11,950,939	3,812,307	568,668	1,444,608	4,838,733,296
97	Summer Energy Charge Adder ($/kWh)	$ 0.000000		$ -	$ -	$ -	$ -	
98								
99	*All Months*	$ -		$ -	$ -	$ -	$ -	
100	Annual Billed Demand	41,358,581	Sum Max Demands	124,124	45,263	6,677	17,064	41,358,581
101	Annual Demand Charge ($/kW)	$ -		$ -	$ -	$ -	$ -	
102	Annual Billed Energy	11,813,938,683	kWh Sold	31,713,621	11,564,634	1,706,004	4,359,820	11,813,938,683
103	Annual Energy Charge ($/kWh)	$ -		$ -	$ -	$ -	$ -	
104								
105	*Transmission Demand Related Summary*							
106	On-Peak Demand Charge ($/kW)	**$ 0.00**		**$ -**	**$ -**	**$ -**	**$ -**	
107	Off-Peak Demand Charge ($/kW)	**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	
108	On-Peak Demand Charge ($/kWh)	**$ 0.000000**		**$ -**	**$ -**	**$ -**	**$ -**	
109	Off-Peak Demand Charge ($/kWh)	**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	
110								
111	**Total Transmission**	$ 65,915,251		$ 2,478	$ -	$ 169	$ 10,147	$ 65,915,251
112								
113								

Test Year Cost of Service for Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A		B	C	L	M	N	O	P
114	**Distribution**							
115	**Demand**							
116	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -
117	Annual	145,509,111		613,560	237,348	34,123	196,236	145,509,111
118	Total Demand	$ 145,509,111		$ 613,560	$ 237,348	$ 34,123	$ 196,236	$ 145,509,111
119								
120	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	
121	Summer Billed Demand	14,807,767	Sum Max Demands - S	46,775	14,921	2,226	5,654	14,807,767
122	Summer Demand Charge Adder ($/kW)	$ -		$ -	$ -	$ -	$ -	
123	Summer Billed Energy	4,838,733,296	kWh Sold - S	11,950,939	3,812,307	568,668	1,444,608	4,838,733,296
124	Summer Energy Charge Adder ($/kWh)	$ -		$ -	$ -	$ -	$ -	
125	Summer Customer Months	1,641,080	No. Cust Mo. - S	16	-	4	158	1,641,080
126	Summer Customer Charge ($/Cust-Month)	$ -		$ -		$ -	$ -	
127								
128	*All Months*	$ 145,509,111		$ 613,560	$ 237,348	$ 34,123	$ 196,236	
129	Annual Billed Demand	41,358,581	Sum Max Demands	124,124	45,263	6,677	17,064	41,358,581
130	Annual Demand Charge ($/kW)	$ 3.52		$ 4.94	$ 5.24	$ 5.11	$ 11.50	
131	Annual Billed Energy	11,813,938,683	kWh Sold	31,713,621	11,564,634	1,706,004	4,359,820	11,813,938,683
132	Annual Energy Charge ($/kWh)	$ 0.012317		$ 0.019347	$ 0.020524	$ 0.020002	$ 0.045010	
133	Annual Customer Months	4,923,240	No. Cust Mo.	48	-	12	473	4,923,240
134	Annual Customer Charge ($/Cust-Month)	$ 29.56		$ 12,782.50		$ 2,843.56	$ 415.12	
135								
136	*Distribution Demand Related Summary*							
137	On-Peak Demand Charge ($/kW)	**$ 3.52**		**$ 4.94**	**$ 5.24**	**$ 5.11**	**$ 11.50**	
138	Off-Peak Demand Charge ($/kW)	**$ 3.52**		**$ 4.94**	**$ 5.24**	**$ 5.11**	**$ 11.50**	
139	On-Peak Demand Charge ($/kWh)	**$ 0.012317**		**$ 0.019347**	**$ 0.020524**	**$ 0.020002**	**$ 0.045010**	
140	Off-Peak Demand Charge ($/kWh)	**$ 0.012317**		**$ 0.019347**	**$ 0.020524**	**$ 0.020002**	**$ 0.045010**	
141	On-Peak Customer Charge ($/Cust-Month)	**$ 29.56**		**$ 12,782.50**		**$ 2,843.56**	**$ 415.12**	
142	Off-Peak Customer Charge ($/Cust-Month)	**$ 29.56**		**$ 12,782.50**		**$ 2,843.56**	**$ 415.12**	
143								
144	**Customer**							
145	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -
146	Annual	17,108,086		-	-	-	1,329	17,108,086
147	Total Customer	$ 17,108,086		$ -	$ -	$ -	$ 1,329	$ 17,108,086
148								
149	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	
150								
151								
152	Summer Customer Months	1,641,080	No. Cust Mo. - S	16	-	4	158	1,641,080
153	Summer Customer Charge Adder ($/Cust-Mo	$ -		$ -		$ -	$ -	
154								
155	*All Months*	$ 17,108,086		$ -	$ -	$ -	$ 1,329	
156								
157								
158	Annual Customer Months	4,923,240	No. Cust Mo.	48	-	12	473	4,923,240
159	Annual Customer Charge ($/Cust-Month)	$ 3.47		$ -		$ -	$ 2.81	
160								
161	*Distribution Customer Related Summary*							
162								
163								
164	On-Peak Customer Charge ($/Cust-Month)	**$ 3.47**		**$ -**		**$ -**	**$ 2.81**	
165	Off-Peak Customer Charge ($/Cust-Month)	**$ 3.47**		**$ -**		**$ -**	**$ 2.81**	
166								
167	**Lighting**							
168	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -
169	Annual	9,835,657		7,287,020	2,548,637	-	-	9,835,657
170	Total Lighting	$ 9,835,657		$ 7,287,020	$ 2,548,637	$ -	$ -	$ 9,835,657

Test Year Cost of Service for Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A		B	C	L	M	N	O	P
171								
172	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	
173								
174								
175	Summer City-Owned Bulb Count	234,484	City-Owned Bulb-Mo. - S	173,724	60,760	-	-	234,484
176	Summer Bulb Charge Adder ($/Bulb-Month)	$ -		$ -	$ -			
177								
178	*All Months*	$ 9,835,657		$ 7,287,020	$ 2,548,637	$ -	$ -	
179								
180								
181	Annual City-Owned Bulb Count	703,452	City-Owned Bulb-Mo.	521,172	182,280	-	-	703,452
182	Annual Bulb Charge ($/Bulb-Month)	$ 13.98		$ 13.98	$ 13.98			
183								
184	*Distribution Lighting Direct Summary*							
185								
186								
187	On-Peak Lighting Charge ($/Bulb-Month)	**$ 13.98**		**$ 13.98**	**$ 13.98**			
188	Off-Peak Lighting Charge ($/Bulb-Month)	**$ 13.98**		**$ 13.98**	**$ 13.98**			
189								
190	**Total Distribution**	$ 172,452,854		$ 7,900,580	$ 2,785,985	$ 34,123	$ 197,565	$ 172,452,854
191								
192								
193	**Customer**							
194	**Customer**							
195	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -
196	Annual	95,921,868		650	-	163	8,410	95,921,868
197	Total Customer	$ 95,921,868		$ 650	$ -	$ 163	$ 8,410	$ 95,921,868
198								
199	**Pass-Throughs**							
200	Regulatory On-Peak	$ -		$ -	$ -	$ -	$ -	$ -
201	Regulatory Annual	-		-	-	-	-	-
202	Community Benefit On-Peak	-		-	-	-	-	-
203	Community Benefit Annual	-		-	-	-	-	-
204	Total Pass-Throughs	$ -		$ -	$ -	$ -	$ -	$ -
205								
206	**Net Recovered from Base Rates**							
207	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -
208	Annual	95,921,868		650	-	163	8,410	95,921,868
209	Total Net Recovered from Base Rates	$ 95,921,868		$ 650	$ -	$ 163	$ 8,410	$ 95,921,868
210								
211	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	
212								
213								
214	Summer Customer Months	1,641,080	No. Cust Mo. - S	16	-	4	158	1,641,080
215	Summer Customer Charge Adder ($/Cust-Mo	$ -		$ -		$ -	$ -	
216								
217	*All Months*	$ 95,921,868		$ 650	$ -	$ 163	$ 8,410	
218								
219								
220	Annual Customer Months	4,923,240	No. Cust Mo.	48	-	12	473	4,923,240
221	Annual Customer Charge ($/Cust-Month)	$ 19.48		$ 13.54		$ 13.54	$ 17.79	
222								
223	*Customer Customer Related Summary*							
224								
225								
226	On-Peak Customer Charge ($/Cust-Month)	**$ 19.48**		**$ 13.54**		**$ 13.54**	**$ 17.79**	
227	Off-Peak Customer Charge ($/Cust-Month)	**$ 19.48**		**$ 13.54**		**$ 13.54**	**$ 17.79**	

Test Year Cost of Service for Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A		B	C	L	M	N	O	P
228								
229	**Total Customer**	$ 95,921,868		$ 650	$ -	$ 163	$ 8,410	$ 95,921,868
230								
231								
232	**Adders**							
233	**City-Owned (Service Area) Street Lighting**							
234	**Adder**							
235	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -
236	Annual	-		(10,434,438)	35,459	1,619	7,831	(0)
237	Total Adder	$ -		$ (10,434,438)	$ 35,459	$ 1,619	$ 7,831	$ (0)
238								
239	**Recovered from Pass-Through**							
240	Community Benefit On-Peak	$ -		$ -	$ -	$ -	$ -	$ -
241	Community Benefit Annual	10,434,438		-	35,459	1,619	7,831	10,434,438
242	Total Recovered from Pass-Through	$ 10,434,438		$ -	$ 35,459	$ 1,619	$ 7,831	$ 10,434,438
243								
244	**Net Recovered from Base Rates**							
245	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -
246	Annual	(10,434,438)		(10,434,438)	(0)	(0)	(0)	(10,434,438)
247	Total Net Recovered from Base Rates	$ (10,434,438)		$ (10,434,438)	$ (0)	$ (0)	$ (0)	$ (10,434,438)
248								
249	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	
250	Summer Billed Demand	14,807,767	Sum Max Demands - S	46,775	14,921	2,226	5,654	14,807,767
251	Summer Demand Charge Adder ($/kW)	$ -		$ -	$ -	$ -	$ -	
252	Summer Billed Energy	4,838,733,296	kWh Sold - S	11,950,939	3,812,307	568,668	1,444,608	4,838,733,296
253	Summer Energy Charge Adder ($/kWh)	$ -		$ -	$ -	$ -	$ -	
254								
255	*All Months*	$ (10,434,438)		$ (10,434,438)	$ (0)	$ (0)	$ (0)	
256	Annual Billed Demand	41,358,581	Sum Max Demands	124,124	45,263	6,677	17,064	41,358,581
257	Annual Demand Charge ($/kW)	$ (0.25)		$ (84.06)	$ (0.00)	$ (0.00)	$ (0.00)	
258	Annual Billed Energy	11,813,938,683	kWh Sold	31,713,621	11,564,634	1,706,004	4,359,820	11,813,938,683
259	Annual Energy Charge ($/kWh)	$ (0.000883)		$ (0.329021)	$ (0.000000)	$ (0.000000)	$ (0.000000)	
260								
261	*City-Owned (Service Area) Street Lighting Summary*							
262	On-Peak Adder ($/kW)	**$ (0.25)**		**$ (84.06)**	**$ (0.00)**	**$ (0.00)**	**$ (0.00)**	
263	Off-Peak Adder ($/kW)	**$ (0.25)**		**$ (84.06)**	**$ (0.00)**	**$ (0.00)**	**$ (0.00)**	
264	On-Peak Adder ($/kWh)	**$ (0.000883)**		**$ (0.329021)**	**$ (0.000000)**	**$ (0.000000)**	**$ (0.000000)**	
265	Off-Peak Adder ($/kWh)	**$ (0.000883)**		**$ (0.329021)**	**$ (0.000000)**	**$ (0.000000)**	**$ (0.000000)**	
266								
267	**Total City-Owned (Service Area) Street Lighting**	$ -		$ (10,434,438)	$ 35,459	$ 1,619	$ 7,831	$ (0)
268								
269								
270	**Pass-Throughs**							
271	**Energy Adjustment**							
272	**Pass-Through**							
273	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -
274	Annual	-		-	-	-	-	-
275	Total Pass-Through	$ -		$ -	$ -	$ -	$ -	$ -
276								
277	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	
278								
279								
280	Summer Billed Energy	4,731,673,910	kWh Sold Net GC - S	11,950,939	3,812,307	568,668	1,444,608	4,731,673,910
281	Summer Energy Adjustment Adder ($/kWh)	$ -		$ -	$ -	$ -	$ -	
282								
283	*All Months*	$ -		$ -	$ -	$ -	$ -	

Test Year Cost of Service for Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A		B	C	L	M	N	O	P
284								
285								
286	Annual Billed Energy	11,561,258,164	kWh Sold Net GC	31,713,621	11,564,634	1,706,004	4,331,628	11,561,258,164
287	Annual Energy Adjustment ($/kWh)	$ -		$ -	$ -	$ -	$ -	
288								
289	*Energy Adjustment Summary*							
290								
291								
292	On-Peak Energy Adjustment ($/kWh)	**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	
293	Off-Peak Energy Adjustment ($/kWh)	**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	
294								
295	**Total Energy Adjustment**	$ -		$ -	$ -	$ -	$ -	$ -
296								
297								
298	**Regulatory**							
299	**Pass-Through**							
300	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -
301	Annual	75,755,050		29,603	9,891	1,628	13,852	75,755,050
302	Total Pass-Through	$ 75,755,050		$ 29,603	$ 9,891	$ 1,628	$ 13,852	$ 75,755,050
303								
304	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	
305	Summer Billed Demand	14,807,767	Sum Max Demands - S	46,775	14,921	2,226	5,654	14,807,767
306	Summer Demand Charge Adder ($/kW)	$ -		$ -	$ -	$ -	$ -	
307	Summer Billed Energy	4,838,733,296	kWh Sold - S	11,950,939	3,812,307	568,668	1,444,608	4,838,733,296
308	Summer Energy Charge Adder ($/kWh)	$ -		$ -	$ -	$ -	$ -	
309								
310	*All Months*	$ 75,755,050		$ 29,603	$ 9,891	$ 1,628	$ 13,852	
311	Annual Billed Demand	41,358,581	Sum Max Demands	124,124	45,263	6,677	17,064	41,358,581
312	Annual Demand Charge ($/kW)	$ 1.83		$ 0.24	$ 0.22	$ 0.24	$ 0.81	
313	Annual Billed Energy	11,813,938,683	kWh Sold	31,713,621	11,564,634	1,706,004	4,359,820	11,813,938,683
314	Annual Energy Charge ($/kWh)	$ 0.006412		$ 0.000933	$ 0.000855	$ 0.000954	$ 0.003177	
315								
316	*Regulatory Summary*							
317	On-Peak Regulatory Charge ($/kW)	**$ 1.83**		**$ 0.24**	**$ 0.22**	**$ 0.24**	**$ 0.81**	
318	Off-Peak Regulatory Charge ($/kW)	**$ 1.83**		**$ 0.24**	**$ 0.22**	**$ 0.24**	**$ 0.81**	
319	On-Peak Regulatory Charge ($/kWh)	**$ 0.006412**		**$ 0.000933**	**$ 0.000855**	**$ 0.000954**	**$ 0.003177**	
320	Off-Peak Regulatory Charge ($/kWh)	**$ 0.006412**		**$ 0.000933**	**$ 0.000855**	**$ 0.000954**	**$ 0.003177**	
321								
322	**Total Regulatory**	$ 75,755,050		$ 29,603	$ 9,891	$ 1,628	$ 13,852	$ 75,755,050
323								
324								
325	**Community Benefit --- City-Owned (Service Area) Street Lighting**							
326	**Pass-Through**							
327	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -
328	Annual	10,434,438		-	35,459	1,619	7,831	10,434,438
329	Total Pass-Through	$ 10,434,438		$ -	$ 35,459	$ 1,619	$ 7,831	$ 10,434,438
330								
331	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	
332	Summer Billed Demand	14,807,767	Sum Max Demands - S	46,775	14,921	2,226	5,654	14,807,767
333	Summer Demand Charge Adder ($/kW)	$ -		$ -	$ -	$ -	$ -	
334	Summer Billed Energy	4,838,733,296	kWh Sold - S	11,950,939	3,812,307	568,668	1,444,608	4,838,733,296
335	Summer Energy Charge Adder ($/kWh)	$ -		$ -	$ -	$ -	$ -	
336								
337	*All Months*	$ 10,434,438		$ -	$ 35,459	$ 1,619	$ 7,831	
338	Annual Billed Demand	41,358,581	Sum Max Demands	124,124	45,263	6,677	17,064	41,358,581
339	Annual Demand Charge ($/kW)	$ 0.25		$ -	$ 0.78	$ 0.24	$ 0.46	
340	Annual Billed Energy	11,813,938,683	kWh Sold	31,713,621	11,564,634	1,706,004	4,359,820	11,813,938,683

Test Year Cost of Service for Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A		B	C	L	M	N	O	P
341	Annual Energy Charge ($/kWh)	$ 0.000883		$ -	$ 0.003066	$ 0.000949	$ 0.001796	
342								
343	*Community Benefit --- City-Owned (Service Area) Street Lighting Summary*							
344	On-Peak Community Benefit ($/kW)	**$ 0.25**		**$ -**	**$ 0.78**	**$ 0.24**	**$ 0.46**	
345	Off-Peak Community Benefit ($/kW)	**$ 0.25**		**$ -**	**$ 0.78**	**$ 0.24**	**$ 0.46**	
346	On-Peak Community Benefit ($/kWh)	**$ 0.000883**		**$ -**	**$ 0.003066**	**$ 0.000949**	**$ 0.001796**	
347	Off-Peak Community Benefit ($/kWh)	**$ 0.000883**		**$ -**	**$ 0.003066**	**$ 0.000949**	**$ 0.001796**	
348								
349	**Community Benefit --- Energy Efficiency**							
350	**Pass-Through**							
351	On-Peak	$ -		$ -	$ -	$ -	$ -	$ -
352	Annual	27,720,129		254,612	93,335	4,262	20,611	27,720,129
353	Total Pass-Through	$ 27,720,129		$ 254,612	$ 93,335	$ 4,262	$ 20,611	$ 27,720,129
354								
355	*On-Peak (June - September)*	$ -		$ -	$ -	$ -	$ -	
356	Summer Billed Demand	14,807,767	Sum Max Demands - S	46,775	14,921	2,226	5,654	14,807,767
357	Summer Demand Charge Adder ($/kW)	$ -		$ -	$ -	$ -	$ -	
358	Summer Billed Energy	4,838,733,296	kWh Sold - S	11,950,939	3,812,307	568,668	1,444,608	4,838,733,296
359	Summer Energy Charge Adder ($/kWh)	$ -		$ -	$ -	$ -	$ -	
360								
361	*All Months*	$ 27,720,129		$ 254,612	$ 93,335	$ 4,262	$ 20,611	
362	Annual Billed Demand	41,358,581	Sum Max Demands	124,124	45,263	6,677	17,064	41,358,581
363	Annual Demand Charge ($/kW)	$ 0.67		$ 2.05	$ 2.06	$ 0.64	$ 1.21	
364	Annual Billed Energy	11,813,938,683	kWh Sold	31,713,621	11,564,634	1,706,004	4,359,820	11,813,938,683
365	Annual Energy Charge ($/kWh)	$ 0.002346		$ 0.008028	$ 0.008071	$ 0.002498	$ 0.004728	
366								
367	*Community Benefit --- Energy Efficiency Summary*							
368	On-Peak Community Benefit ($/kW)	**$ 0.67**		**$ 2.05**	**$ 2.06**	**$ 0.64**	**$ 1.21**	
369	Off-Peak Community Benefit ($/kW)	**$ 0.67**		**$ 2.05**	**$ 2.06**	**$ 0.64**	**$ 1.21**	
370	On-Peak Community Benefit ($/kWh)	**$ 0.002346**		**$ 0.008028**	**$ 0.008071**	**$ 0.002498**	**$ 0.004728**	
371	Off-Peak Community Benefit ($/kWh)	**$ 0.002346**		**$ 0.008028**	**$ 0.008071**	**$ 0.002498**	**$ 0.004728**	
372								
373	**Total Community Benefit**	$ 38,154,567		$ 254,612	$ 128,793	$ 5,881	$ 28,442	$ 38,154,567
374								
375								
376								
377	**Total Base Rate Unit Costs**							
378	**On-Peak (June - Sept)**							
379	Customer-Related							
380	$/Cust-Month			$ 13.54		$ 13.54	$ 20.60	
381	Demand-Related							
382	Production & Transmission							
383	$/kW							
384	$/kWh			$ 0.036479	$ 0.047911	$ 0.045591	$ 0.110119	
385	Distribution (wires)							
386	$/kW							
387	$/kWh			$ 0.019347	$ 0.020524	$ 0.020002	$ 0.045010	
388	$/Cust-Month							
389	$/Bulb-Month			$ 13.98	$ 13.98			
390	Adder							
391	$/kW							
392	$/kWh			$ (0.329021)	$ (0.000000)	$ (0.000000)	$ (0.000000)	
393	Energy-Related							
394	$/kWh			$ 0.038177	$ 0.038177	$ 0.038177	$ 0.038177	
395								

Test Year Cost of Service for Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Transfer to the Rate Design Mode

Line No.		Test Year	Allocation Basis	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A		B	C	L	M	N	O	P
396	**Off-Peak**							
397	Customer-Related							
398	$/Cust-Month			$ 13.54		$ 13.54	$ 20.60	
399	Demand-Related							
400	Production & Transmission							
401	$/kW							
402	$/kWh			$ 0.032927	$ 0.042651	$ 0.040635	$ 0.098085	
403	Distribution (wires)							
404	$/kW							
405	$/kWh			$ 0.019347	$ 0.020524	$ 0.020002	$ 0.045010	
406	$/Cust-Month							
407	$/Bulb-Month			$ 13.98	$ 13.98			
408	Adder							
409	$/kW							
410	$/kWh			$ (0.329021)	$ (0.000000)	$ (0.000000)	$ (0.000000)	
411	Energy-Related							
412	$/kWh			$ 0.035727	$ 0.035727	$ 0.035727	$ 0.035727	
413								
414	**Total Pass-Through Unit Costs**							
415	**On-Peak (June - Sept)**							
416	Demand-Related							
417	**Regulatory**							
418	$/kW							
419	$/kWh			$ 0.000933	$ 0.000855	$ 0.000954	$ 0.003177	
420								
421	**Community Benefit --- City-Owned (Service Area) Street Lighting**							
422	$/kW							
423	$/kWh				$ 0.003066	$ 0.000949	$ 0.001796	
424								
425	**Community Benefit --- Energy Efficiency**							
426	$/kW							
427	$/kWh			$ 0.008028	$ 0.008071	$ 0.002498	$ 0.004728	
428								
429	Energy-Related							
430	**Energy Adjustment**							
431	$/kWh			$ -	$ -	$ -	$ -	
432								
433	**Off-Peak**							
434	Demand-Related							
435	**Regulatory**							
436	$/kW							
437	$/kWh			$ 0.000933	$ 0.000855	$ 0.000954	$ 0.003177	
438								
439	**Community Benefit --- City-Owned (Service Area) Street Lighting**							
440	$/kW							
441	$/kWh				$ 0.003066	$ 0.000949	$ 0.001796	
442								
443	**Community Benefit --- Energy Efficiency**							
444	$/kW							
445	$/kWh			$ 0.008028	$ 0.008071	$ 0.002498	$ 0.004728	
446								
447	Energy-Related							
448	**Energy Adjustment**							
449	$/kWh			$ -	$ -	$ -	$ -	
450								

Test Year Cost of Service for Time of Use (TOU) Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Development of Time of Use (TOU) Rates

Line No.		Data Source	Test Year	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW	Primary Voltage ≥ 20 MW	Transmission Voltage
A		B	C	D	E	F	G	H	I	J	K
1	**Production Revenue Requirement**										
2	Demand Related										
3	Base Load	COS	$ 259,950,975	$ 107,045,359	$ 9,051,256	$ 23,494,921	$ 84,971,625	$ 6,822,056	$ 11,007,363	$ 12,866,582	$ 3,031,935
4	Intermediate	COS	58,658,794	24,155,138	2,042,446	5,301,706	19,174,127	1,539,419	2,483,848	2,903,387	684,166
5	Peak	COS	12,952,332	5,333,648	450,988	1,170,659	4,233,801	339,916	548,453	641,091	151,069
6	Total Demand Related		$ 331,562,101	$ 136,534,144	$ 11,544,690	$ 29,967,286	$ 108,379,553	$ 8,701,391	$ 14,039,664	$ 16,411,059	$ 3,867,171
7											
8	Energy Related										
9	Base Load	COS	$ 253,916,309	$ 84,084,961	$ 8,158,022	$ 21,175,717	$ 88,077,979	$ 8,564,215	$ 16,606,454	$ 20,887,012	$ 5,273,467
10	Intermediate	COS	153,295,739	50,764,231	4,925,205	12,784,319	53,174,918	5,170,434	10,025,739	12,610,021	3,183,727
11	Peak	COS	11,546,911	4,425,673	343,905	917,181	3,765,398	368,665	665,897	809,983	206,639
12	Total Energy Related		$ 418,758,958	$ 139,274,866	$ 13,427,132	$ 34,877,217	$ 145,018,294	$ 14,103,314	$ 27,298,090	$ 34,307,015	$ 8,663,833
13											
14	Total		$ 750,321,059	$ 275,809,010	$ 24,971,822	$ 64,844,504	$ 253,397,848	$ 22,804,705	$ 41,337,754	$ 50,718,074	$ 12,531,004
15											
16	**Time of Use Billing Data (before Demand Response)**										
17	Billed Demand (kW)	SD-77, SD-78 & SD-79									
18	On-Peak Demand (2PM-8PM M-F Summer Months)			4,195,878	344,087	900,667	3,339,127	269,577	421,579	492,445	130,567
19	Intermediate Demand (Summer On-Peak plus 6AM - 10 PM All Days Winter Months)			5,836,785	687,173	1,421,359	5,257,939	441,120	801,647	964,408	256,887
20	Off-Peak Demand (Not billed in other Hours for Summer and Winter Months)			-	-	-	-	-	-	-	-
21	Total kW			10,032,663	1,031,260	2,322,026	8,597,066	710,697	1,223,226	1,456,853	387,455
22											
23	Billed Energy - Summer (kWh)										
24	On-Peak	SD-77, SD-78 & SD-79		427,358,274	36,587,618	91,841,813	348,395,913	30,645,908	50,190,454	61,735,157	15,039,762
25	Intermediate	SD-77, SD-78 & SD-79		897,779,198	70,942,672	200,943,913	829,178,786	78,562,976	136,943,688	164,315,713	42,379,122
26	Off-Peak	SD-77, SD-78 & SD-79		506,906,940	36,571,828	92,899,972	420,945,912	47,897,731	90,850,915	112,084,244	29,958,266
27	Sub-Total kWh			1,832,044,412	144,102,118	385,685,698	1,598,520,610	157,106,615	277,985,057	338,135,114	87,377,150
28											
29	Billed Energy - Winter (kWh)										
30	On-Peak	SD-77, SD-78 & SD-79		-	-	-	-	-	-	-	-
31	Intermediate	SD-77, SD-78 & SD-79		1,454,795,483	169,367,570	426,521,651	1,799,719,958	171,578,662	331,255,677	421,099,002	105,976,422
32	Off-Peak	SD-77, SD-78 & SD-79		577,561,475	65,415,518	174,829,447	744,368,440	77,262,348	160,589,231	209,030,834	54,266,110
33	Sub-Total kWh			2,032,356,958	234,783,089	601,351,097	2,544,088,398	248,841,011	491,844,908	630,129,836	160,242,532
34											
35	Total kWh			3,864,401,370	378,885,207	987,036,795	4,142,609,008	405,947,626	769,829,965	968,264,949	247,619,682
36											
37	Total kWh Sold			3,864,401,370	378,885,207	987,036,795	4,142,609,008	405,947,626	769,829,965	968,264,949	247,619,682
38	Check (should be 0)			-	-	-	-	-	-	-	-
39											
40	Demand Response:			-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%
41	Energy Response:			-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%
42											
43	**Time of Use Billing Data (after Demand Response)**										
44	Billed Demand (kW)										
45	On-Peak Demand (2PM-8PM M-F Summer Months)			3,986,084	326,883	855,633	3,172,170	256,098	400,500	467,823	124,039
46	Intermediate Demand (Summer On-Peak plus 6AM - 10 PM All Days Winter Months)			5,836,785	687,173	1,421,359	5,257,939	441,120	801,647	964,408	256,887
47	Off-Peak Demand (Not billed in other Hours for Summer and Winter Months)			-	-	-	-	-	-	-	-
48	Total kW			9,822,869	1,014,055	2,276,993	8,430,110	697,219	1,202,147	1,432,230	380,926
49											
50	Billed Energy - Summer (kWh)										
51	On-Peak			405,990,360	34,758,237	87,249,723	330,976,117	29,113,613	47,680,931	58,648,399	14,287,774
52	Intermediate			919,147,112	72,772,053	205,536,004	846,598,581	80,095,271	139,453,210	167,402,471	43,131,110
53	Off-Peak			506,906,940	36,571,828	92,899,972	420,945,912	47,897,731	90,850,915	112,084,244	29,958,266
54	Sub-Total kWh			1,832,044,412	144,102,118	385,685,698	1,598,520,610	157,106,615	277,985,057	338,135,114	87,377,150
55											
56	Billed Energy - Winter (kWh)										
57	On-Peak			-	-	-	-	-	-	-	-

Test Year Cost of Service for Time of Use (TOU) Rate Design

Purpose: Identify the Unbundled Unit Cost of Service by Customer Class for Development of Time of Use (TOU) Rates

Line No.		Data Source	Test Year	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW	Primary Voltage ≥ 20 MW	Transmission Voltage
A		B	C	D	E	F	G	H	I	J	K
58	Intermediate			1,454,795,483	169,367,570	426,521,651	1,799,719,958	171,578,662	331,255,677	421,099,002	105,976,422
59	Off-Peak			577,561,475	65,415,518	174,829,447	744,368,440	77,262,348	160,589,231	209,030,834	54,266,110
60	Sub-Total kWh			2,032,356,958	234,783,089	601,351,097	2,544,088,398	248,841,011	491,844,908	630,129,836	160,242,532
61											
62	Total kWh			3,864,401,370	378,885,207	987,036,795	4,142,609,008	405,947,626	769,829,965	968,264,949	247,619,682
63											
64	Loss Adjustment Factor	WP 23		5.05%	5.05%	5.05%	5.05%	2.85%	2.85%	2.85%	1.60%
65											
66	**ADJUSTMENT TO MEET REVENUE REQUIREMENT**										
67	Billed Energy - Fuel -- Summer		**$/kWh NEFL**								
68	On-Peak	72.0%	$ 0.074360	$ 0.056356	$ 0.056356	$ 0.056356	$ 0.056356	$ 0.055080	$ 0.055080	$ 0.055080	$ 0.054378
69	Intermediate	72.0%	$ 0.060067	$ 0.040554	$ 0.040554	$ 0.040554	$ 0.040554	$ 0.039636	$ 0.039636	$ 0.039636	$ 0.039130
70	Off-Peak		$ 0.017820	$ 0.018768	$ 0.018768	$ 0.018768	$ 0.018768	$ 0.018343	$ 0.018343	$ 0.018343	$ 0.018109
71											
72	Billed Energy - Winter										
73	On-Peak			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Intermediate			$ 0.040554	$ 0.040554	$ 0.040554	$ 0.040554	$ 0.039636	$ 0.039636	$ 0.039636	$ 0.039130
75	Off-Peak			$ 0.018768	$ 0.018768	$ 0.018768	$ 0.018768	$ 0.018343	$ 0.018343	$ 0.018343	$ 0.018109
76											
77											
78	Demand Related										
79	On-Peak (Recovered during Summer Months Only)			$ 1.34	$ 1.38	$ 1.37	$ 1.33	$ 1.33	$ 1.37	$ 1.37	$ 1.22
80	Differential between On-Peak and Intermediate Demand Charge			$ 1.40	$ 1.40	$ 1.40	$ 1.40	$ 1.40	$ 1.40	$ 1.40	$ 1.40
81											
82	TOU Rates										
83	Demand Charge ($/kW)										
84	On-Peak			$ 14.70	$ 12.07	$ 13.72	$ 13.39	$ 13.69	$ 13.77	$ 13.70	$ 12.48
85	Intermediate			$ 13.30	$ 10.67	$ 12.32	$ 11.99	$ 12.29	$ 12.37	$ 12.30	$ 11.08
86											
87	Billed Energy Adjusted for Losses - Summer										
88	On-Peak			$ 0.056356	$ 0.056356	$ 0.056356	$ 0.056356	$ 0.055080	$ 0.055080	$ 0.055080	$ 0.054378
89	Intermediate			$ 0.040554	$ 0.040554	$ 0.040554	$ 0.040554	$ 0.039636	$ 0.039636	$ 0.039636	$ 0.039130
90	Off-Peak			$ 0.018768	$ 0.018768	$ 0.018768	$ 0.018768	$ 0.018343	$ 0.018343	$ 0.018343	$ 0.018109
91											
92	Billed Energy Adjusted for Losses - Winter										
93	On-Peak										
94	Intermediate			$ 0.040554	$ 0.040554	$ 0.040554	$ 0.040554	$ 0.039636	$ 0.039636	$ 0.039636	$ 0.039130
95	Off-Peak			$ 0.018768	$ 0.018768	$ 0.018768	$ 0.018768	$ 0.018343	$ 0.018343	$ 0.018343	$ 0.018109

Work Paper 1 - Trial Balance

Purpose: Provide Audited Financial Results by FERC Account to Reference within the Cost of Service Analysis

Line No.	FERC Account	Description	Source Reference	FY 2009
A	B	C	D	E
1	121	Non-Utility Plant	SD-1	$ 115,423,338
2	301	Organization Cost	SD-1	-
3	302	Franchises and Consents	SD-1	-
4	303	Intangible Plant	SD-1	-
5	310	Land & Land Rights	SD-1	9,266,948
6	311	Structures & Improvements	SD-1	93,697,873
7	312	Boiler Plant Equipment	SD-1	224,540,476
8	313	Engines and Engine Driven Generators	SD-1	-
9	314	Turbogenerator Units	SD-1	76,149,931
10	315	Accessory Plt Equipment	SD-1	31,459,310
11	316	Miscellaneous Equipment	SD-1	62,852,917
12	320	Land & Land Rights	SD-1	2,782,002
13	321	Structures & Improvements	SD-1	406,719,894
14	322	Reactor Plant Equipment	SD-1	300,139,567
15	323	Turbogenerator Units	SD-1	48,391,775
16	324	Accessory Plant Equipment	SD-1	166,803,189
17	325	Miscellaneous Equipment	SD-1	9,054,739
18	340	Land & Land Rights	SD-1	-
19	341	Structures & Improvements	SD-1	8,132,184
20	342	Fuel Holders, Producers and Accessories	SD-1	10,373,600
21	343	Prime movers	SD-1	1,190,306
22	344	Generator/PV	SD-1	299,625,412
23	345	Accessory Elec Equip.	SD-1	3,162,172
24	346	Miscellaneous Equipment	SD-1	2,112,756
25	350	Land & Land Rights	SD-1	20,741,288
26	351	Clearing Land	SD-1	-
27	352	Structures & Improvements	SD-1	23,404,638
28	353	Station Equipment	SD-1	158,890,580
29	354	Towers and Fixtures	SD-1	43,594,735
30	355	Poles and Fixtures	SD-1	60,307,696
31	356	Overhead Conductors and Devices	SD-1	83,557,094
32	357	Underground Conduit	SD-1	4,945,414
33	358	Underground Conductors and Devices	SD-1	8,076,095
34	359	Roads and Trails	SD-1	854,121
35	360	Land & Land Rights	SD-1	6,461,585
36	361	Structures & Improvements	SD-1	28,303,272
37	362	Station Equipment	SD-1	175,135,358
38	363	Storage Equipment	SD-1	36,895
39	364	Poles, Towers & Fixtures	SD-1	157,134,675
40	365	OH Conductors & Devices	SD-1	180,468,419
41	366	UG Conduit	SD-1	150,110,871
42	367	UG Conductors & Devices	SD-1	241,618,710
43	368	Line Transformers	SD-1	202,194,513
44	369	Services	SD-1	32,698,096
45	370	Meters	SD-1	75,906,947
46	371	Installation on Customers' Prem	SD-1	27,630
47	372	Leased Property on Customers' Premises	SD-1	2,738,404
48	373	Streetlighting & Signal Systems	SD-1	77,997,340
49	389	Land & Land Rights	SD-1	24,754,793
50	390	Structures & Improvements	SD-1	65,479,509
51	391	Office Furniture & Equipment	SD-1	71,900,419
52	392	Transportation Equipment	SD-1	26,923,502

Work Paper 1 - Trial Balance

Purpose: Provide Audited Financial Results by FERC Account to Reference within the Cost of Service Analysis

Line No.	FERC Account	Description	Source Reference	FY 2009
A	B	C	D	E
53	393	Stores Equipment	SD-1	620,372
54	394	Tools, Shop & Garage Equipment	SD-1	3,658,641
55	395	Laboratory Equipment	SD-1	776,927
56	396	Power Operated Equipment	SD-1	1,838,793
57	397	Communications Equipment	SD-1	52,563,496
58	398	Miscellaneous Equipment	SD-1	280,205
59	399	Other Tangible Property	SD-1	-
60	105	Plant Held for Future Use	SD-2	27,783,011
61	107	Construction Work in Progress	SD-2	385,599,829
62	108	Accumulated Depreciation	SD-1	(1,791,382,274)
63	114	Acquisition Adjustment	SD-1	(6,599,053)
64	120	Nuclear Fuel	SD-2	243,744,615
65	120.5	Amortization of Nuclear Fuel	SD-2	(210,627,048)
66	125	Sinking Funds	SD-2	235,301,831
67	128	Other Special Funds	SD-2	287,066,204
68	131	Cash	SD-2	18,000
69	135	Working Funds	SD-2	3,393,202
70	136	Temporary Cash Investments	SD-2	211,297,463
71	141	Note Receivable	SD-2	2,738,282
72	142	Accounts Receivable	SD-2	134,005,853
73	143	Other Accounts Receivable	SD-2	6,475,663
74	144	Provision for uncollectable receivables	SD-2	(2,214,445)
75	151	Fuel Stock	SD-2	44,930,580
76	154	Materials and Supplies	SD-2	43,773,566
77	158	Allowance Inventory	SD-2	-
78	165	Prepayments	SD-2	3,709,974
79	173	Accrued Utility Revenues	SD-2	(22,696,920)
80	181	Unamortized Debt Expense	SD-2	8,769,748
81	184	Clearing Account	SD-2	173,485
82	186	Miscellaneous Deferred Debits	SD-2	180,677,759
83	208	Investments of Municipality	SD-2	(4,233,217)
84	211	Miscellaneous Capital	SD-2	-
85	215	Retained Earnings	SD-2	(1,620,766,338)
86	221	Bonds	SD-2	(1,265,190,537)
87	224	Other Long Term Debt	SD-2	-
88	225	Unamortized Premium on LTD 744	SD-2	(37,991,126)
89	226	Unamortized Discount on LTD 743	SD-2	3,568,745
90	227	Obligations Under Capital Lease - Non-Current	SD-2	(1,126,585)
91	228	Accumulated Operating Provisions	SD-2	(213,197,287)
92	231	Notes Payable	SD-2	(140,707,026)
93	232	Accounts Payable	SD-2	(70,909,364)
94	235	Customer Deposits	SD-2	(18,400,929)
95	235.5	Escrow Deposits	SD-2	(3,245,097)
96	237	Accrued Interest	SD-2	(125,384,551)
97	242	Miscellaneous Current and Accrued Liabilities	SD-2	(26,874,482)
98	243	Obligations Under Capital Lease-Current	SD-2	(36,371)
99	253	Other Deferred Credits	SD-2	(115,427,338)
100	400	Operating Revenue	SD-2	(1,165,934,794)
101	500	Operation Supervision and Engineering	SD-3	8,461,250
102	501	Fuel	SD-3	304,171,444
103	502	Steam Expenses	SD-3	4,100,525
104	503	Steam from other Sources	SD-3	-

Work Paper 1 - Trial Balance

Purpose: Provide Audited Financial Results by FERC Account to Reference within the Cost of Service Analysis

Line No.	FERC Account	Description	Source Reference	FY 2009
A	B	C	D	E
105	504	Steam Transferred	SD-3	-
106	505	Electric Expenses	SD-3	5,013,588
107	506	Miscellaneous Steam Expenses	SD-3	4,394,541
108	507	Rents	SD-3	146
109	510	Maintenance Supervision	SD-3	2,273,086
110	511	Maintenance of Structures	SD-3	215,751
111	512	Maintenance of Boiler Plant	SD-3	6,356,222
112	513	Maintenance of Electric Plant	SD-3	3,534,272
113	514	Maintenance of Miscellaneous Steam Plant	SD-3	3,553,188
114	515	Rents	SD-3	-
115	517	Operation Supervision	SD-3	9,211,756
116	518	Nuclear Fuel Expense	SD-3	16,866,183
117	519	Coolants and Water	SD-3	953,232
118	520	Steam Expenses	SD-3	1,458,922
119	523	Electric Expenses	SD-3	4,134,216
120	524	Misc Nuclear Power Expenses	SD-3	12,914,335
121	525	Rents	SD-3	-
122	528	Maintenance Supervision	SD-3	4,898,622
123	529	Maintenance of Structures	SD-3	2,347,069
124	530	Maintenance of Reactor Plant	SD-3	5,620,149
125	531	Maintenance of Electric Plant	SD-3	2,852,587
126	532	Maintenance of Miscellaneous	SD-3	662,509
127	537	Hydraulic Expense	SD-3	-
128	541	Maintenance Supervision	SD-3	-
129	542	Maintenance of Structures	SD-3	-
130	543	Maintenance of Reservoirs, Dams & Waterways	SD-3	-
131	544	Maintenance of Electric Plant	SD-3	-
132	545	Maintenance of Miscellaneous Hydraulic Plant	SD-3	-
133	546	Operation Supervision	SD-3	2,356,493
134	547	Fuel	SD-3	4,206
135	548	Generation Expenses	SD-3	2,489,508
136	549	Miscellaneous Other Power Generation Expenses	SD-3	130,467
137	550	Rents	SD-3	205,134
138	551	Maintenance Supervision and Engineering	SD-3	22,617
139	552	Maintenance of Structures	SD-3	105,620
140	553	Maintenance of Generating and Electric Equipment	SD-3	8,172,762
141	554	Maintenance of Misc Other Power Generation Plant	SD-3	1,169,131
142	555	Purchased Power	SD-3	105,508,856
143	556	System Control and Load Dispatching	SD-3	22,712,824
144	557	Other Power Expenses	SD-3	461,942
145	560	Operations Supervision and Engineering	SD-3	4,139,800
146	561	Load Dispatching	SD-3	1,581,229
147	562	Station Expenses	SD-3	181,382
148	563	Overhead Line Expenses	SD-3	291,702
149	564	Underground Line Expenses	SD-3	(189)
150	565	Transmission of Electricity by Others	SD-3	58,477,601
151	566	Miscellaneous Transmission Expenses	SD-3	589,653
152	567	Rents	SD-3	3,000
153	568	Maintenance Supervision and Engineering	SD-3	343,997
154	569	Maintenance of Structures	SD-3	22,031
155	570	Maintenance of Station Equipment	SD-3	(57,698)
156	571	Maintenance of Overhead Lines	SD-3	1,286,533

Work Paper 1 - Trial Balance

Purpose: Provide Audited Financial Results by FERC Account to Reference within the Cost of Service Analysis

Line No.	FERC Account	Description	Source Reference	FY 2009
A	B	C	D	E
157	572	Maintenance of Underground Lines	SD-3	36,353
158	573	Maintenance of Miscellaneous Transmission Plant	SD-3	17,866
159	580	Operations Supervision and Engineering	SD-3	8,214,447
160	581	Load Dispatching	SD-3	2,167,575
161	582	Station Expenses	SD-3	1,189,288
162	583	Overhead Line Expenses	SD-3	2,985,415
163	584	Underground Line Expenses	SD-3	(674,154)
164	585	Street Lighting	SD-3	104,565
165	586	Meter Expenses	SD-3	3,931,002
166	587	Customer Installation Expenses	SD-3	135,513
167	588	Miscellaneous Distribution Expenses	SD-3	3,176,834
168	589	Rents	SD-3	(507)
169	590	Maintenance Supervision and Engineering	SD-3	137,125
170	591	Maintenance of Structures	SD-3	104,947
171	592	Maintenance of Station Equipment	SD-3	2,551,043
172	593	Maintenance of Overhead Lines	SD-3	12,378,588
173	594	Maintenance of Underground Lines	SD-3	157,935
174	595	Maintenance of Line Transformers	SD-3	6,916
175	596	Maintenance of Street Lighting and Signal Systems	SD-3	1,382,155
176	597	Maintenance of Meters	SD-3	68,127
177	598	Maintenance of Miscellaneous Distribution Plant	SD-3	1,141,171
178	901	Supervision	SD-3	201,021
179	902	Meter Reading Expenses	SD-3	11,108,833
180	903	Customer Records and Collection Expenses	SD-3	27,215,210
181	904	Uncollectible Accounts	SD-3	3,649,195
182	905	Miscellaneous Customer Accounts Expenses	SD-3	(15,251,452)
183	907	Supervision	SD-3	3,237,337
184	908	Customer Assistance Expenses	SD-3	22,959,873
185	909	Informational & Instructional Advertising Expenses	SD-3	1,022,743
186	910	Misc Customer Service & Informational Expenses	SD-3	750,929
187	911	Supervision	SD-3	8,324,843
188	912	Demonstrating & Selling Expense	SD-3	3,222,289
189	913	Advertising Expense	SD-3	448,021
190	916	Miscellaneous Sales Expense	SD-3	452,925
191	920	Administrative and General Salaries	SD-3	38,780,376
192	921	Office Supplies and Expenses	SD-3	28,007,506
193	922	Administrative Expense Transferred	SD-3	(287,411)
194	923	Outside Services Employed	SD-3	10,565,986
195	924	Property Insurance	SD-3	683,345
196	925	Injuries and Damages	SD-3	4,073,967
197	926	Employee Pension and Benefits	SD-3	29,056,796
198	928	Regulatory Commission Expense	SD-3	-
199	929	Duplicate Charges - Credit	SD-3	-
200	930	General Expenses	SD-3	22,428,040
201	931	Rents	SD-3	1,607,142
202	935	Maintenance of General Plant	SD-3	879,615
203	403	Depreciation Expense	SD-3	114,171,721
204	407	Regulatory Debits	SD-3	9,972,536
205	408	Taxes Other Than Income	SD-3	9,117
206	411.6	Loss on Disposal	SD-3	8,125,628
207	417	Expenses - Non-utility operations	SD-3	16,288,944
208	418	Non-operating Rental Income	SD-3	-

Work Paper 1 - Trial Balance

Purpose: Provide Audited Financial Results by FERC Account to Reference within the Cost of Service Analysis

Line No.	FERC Account	Description	Source Reference	FY 2009
A	B	C	D	E
209	419	Interest and Dividend Income	SD-2	(17,401,562)
210	421	Miscellaneous Nonoperating Income	SD-3	(5,177)
211	421.3	Capital Contributions	SD-2	(5,955,845)
212	421.5	General Fund Transfers	SD-3	95,000,000
213	421.6	Transfers In	SD-2	-
214	426	Donations	SD-3	38,342
215	427	Interest Expense	SD-3	81,620,874
216	428	Amortization of Debt Expense	SD-3	699,727
217	428.2	Amortization of Debt Discount	SD-3	4,154,710
218	429	Amortization of Premium on Debt	SD-3	753,949
219	451	Misc Service Revenue	SD-3	22,056

Work Paper 2 - Plant in Service

Purpose: Develop and Functionalize Plant in Service by FERC for the Test Year

Line No.		FERC Account	FY 2009 Source Reference	Adjustments Source Reference	FY 2009 Actual	Adjustments	Test Year	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A		B	C	D	E	F	G	H	I	J	K	L	M
1	**Original Cost of Plant In Service**												
2	Intangible and Non-Utility Plant												
3	Organization Cost	301			$ -		$ -		$ -	$ -	$ -	$ -	$ -
4	Franchises and Consents	302			-		-		-	-	-	-	-
5	Intangible Plant	303			-		-		-	-	-	-	-
6	Non-Utility Plant	121	SD-1	WP 2.2	115,423,338	(115,423,338)	-		-	-	-	-	-
7					$ 115,423,338	$ (115,423,338)	$ -		$ -	$ -	$ -	$ -	$ -
8													
9	Steam Power Generation												
10	Land & Land Rights	310	SD-1		$ 9,234,828		$ 9,234,828	Production	$ 9,234,828	$ -	$ -	$ -	$ 9,234,828
11	Structures & Improvements	311	SD-1	WP 2.1 & 2.2	94,394,936	(4,946,193)	89,448,743	Production	89,448,743	-	-	-	89,448,743
12	Boiler Plant Equipment	312	SD-1	WP 2.1, 2.2 & 2.3	224,540,476	187,295,175	411,835,651	Production	411,835,651	-	-	-	411,835,651
13	Engines and Engine Driven Generators	313	SD-1		-		-	Production	-	-	-	-	-
14	Turbogenerator Units	314	SD-1	WP 2.1	76,149,931	(492,117)	75,657,814	Production	75,657,814	-	-	-	75,657,814
15	Accessory Plt Equipment	315	SD-1	WP 2.1 & 2.2	31,459,310	(744,248)	30,715,062	Production	30,715,062	-	-	-	30,715,062
16	Miscellaneous Equipment	316	SD-1	WP 2.1 & 2.2	62,851,230	(88,119)	62,763,111	Production	62,763,111	-	-	-	62,763,111
17					$ 498,630,712	$ 181,024,498	$ 679,655,210		$ 679,655,210	$ -	$ -	$ -	$ 679,655,210
18													
19	Nuclear Power Generation												
20	Land & Land Rights	320	SD-1		$ 2,782,002		$ 2,782,002	Production	$ 2,782,002	$ -	$ -	$ -	$ 2,782,002
21	Structures & Improvements	321	SD-1		406,719,894		406,719,894	Production	406,719,894	-	-	-	406,719,894
22	Reactor Plant Equipment	322	SD-1	WP 2.1	300,139,567	(6,629,760)	293,509,807	Production	293,509,807	-	-	-	293,509,807
23	Turbogenerator Units	323	SD-1		48,391,775		48,391,775	Production	48,391,775	-	-	-	48,391,775
24	Accessory Plant Equipment	324	SD-1	WP 2.1	166,803,189	(207,040)	166,596,149	Production	166,596,149	-	-	-	166,596,149
25	Miscellaneous Equipment	325	SD-1	WP 2.1	9,054,739	(400,476)	8,654,263	Production	8,654,263	-	-	-	8,654,263
26					$ 933,891,167	$ (7,237,276)	$ 926,653,891		$ 926,653,891	$ -	$ -	$ -	$ 926,653,891
27													
28	Combustion Turbine & Other Production												
29	Land & Land Rights	340	SD-1		$ 32,120		$ 32,120	Production	$ 32,120	$ -	$ -	$ -	$ 32,120
30	Structures & Improvements	341	SD-1	WP 2.2	7,435,121	(697,064)	6,738,057	Production	6,738,057	-	-	-	6,738,057
31	Fuel Holders, Producers and Accessories	342	SD-1		10,373,600		10,373,600	Production	10,373,600	-	-	-	10,373,600
32	Prime movers	343	SD-1		1,190,306		1,190,306	Production	1,190,306	-	-	-	1,190,306
33	Generator/PV	344	SD-1	WP 2.3	299,625,412	72,869,957	372,495,368	Production	372,495,368	-	-	-	372,495,368
34	Accessory Elec Equip.	345	SD-1		3,162,172		3,162,172	Production	3,162,172	-	-	-	3,162,172
35	Miscellaneous Equipment	346	SD-1		2,114,443		2,114,443	Production	2,114,443	-	-	-	2,114,443
36					$ 323,933,174	$ 72,172,893	$ 396,106,067		$ 396,106,067	$ -	$ -	$ -	$ 396,106,067
37													
38	**Total Power Generation Plant**				**$ 1,756,455,053**	**$ 245,960,115**	**$ 2,002,415,168**		**$ 2,002,415,168**	**$ -**	**$ -**	**$ -**	**$ 2,002,415,168**
39													
40	Transmission Plant												
41	Land & Land Rights	350	SD-1	WP 2.1	$ 20,741,288	(1,188)	$ 20,740,100	Transmission	$ -	$ 20,740,100	$ -	$ -	$ 20,740,100
42	Clearing Land	351	SD-1		-		-	Transmission	-	-	-	-	-
43	Structures & Improvements	352	SD-1		23,404,638		23,404,638	Transmission	-	23,404,638	-	-	23,404,638
44	Station Equipment	353	SD-1	WP 2.1	158,890,580	(157,095)	158,733,486	Transmission	-	158,733,486	-	-	158,733,486
45	Towers and Fixtures	354	SD-1		43,594,735		43,594,735	Transmission	-	43,594,735	-	-	43,594,735
46	Poles and Fixtures	355	SD-1		60,307,696		60,307,696	Transmission	-	60,307,696	-	-	60,307,696
47	Overhead Conductors and Devices	356	SD-1		83,557,094		83,557,094	Transmission	-	83,557,094	-	-	83,557,094
48	Underground Conduit	357	SD-1		4,945,414		4,945,414	Transmission	-	4,945,414	-	-	4,945,414
49	Underground Conductors and Devices	358	SD-1		8,076,095		8,076,095	Transmission	-	8,076,095	-	-	8,076,095
50	Roads and Trails	359	SD-1		854,121		854,121	Transmission	-	854,121	-	-	854,121
51					$ 404,371,660	$ (158,282)	$ 404,213,378		$ -	$ 404,213,378	$ -	$ -	$ 404,213,378
52													
53	Distribution Plant												
54	Land & Land Rights	360	SD-1		$ 6,461,585		$ 6,461,585	Distribution	$ -	$ -	$ 6,461,585	$ -	$ 6,461,585
55	Structures & Improvements	361	SD-1		28,303,272		28,303,272	Distribution	-	-	28,303,272	-	28,303,272
56	Station Equipment	362	SD-1	WP 2.1	175,135,358	(54,469)	175,080,889	Distribution	-	-	175,080,889	-	175,080,889
57	Storage Equipment	363	SD-1		36,895		36,895	Distribution	-	-	36,895	-	36,895

Work Paper 2 - Plant in Service

Purpose: Develop and Functionalize Plant in Service by FERC for the Test Year

Line No.		FERC Account	FY 2009 Source Reference	Adjustments Source Reference	FY 2009 Actual	Adjustments	Test Year	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A		B	C	D	E	F	G	H	I	J	K	L	M
58	Poles, Towers & Fixtures	364	SD-1		157,134,675		157,134,675	Distribution	-	-	157,134,675	-	157,134,675
59	OH Conductors & Devices	365	SD-1		180,468,419		180,468,419	Distribution	-	-	180,468,419	-	180,468,419
60	UG Conduit	366	SD-1		150,110,871		150,110,871	Distribution	-	-	150,110,871	-	150,110,871
61	UG Conductors & Devices	367	SD-1		241,618,710		241,618,710	Distribution	-	-	241,618,710	-	241,618,710
62	Line Transformers	368	SD-1		202,194,513		202,194,513	Distribution	-	-	202,194,513	-	202,194,513
63	Services	369	SD-1		32,698,096		32,698,096	Distribution	-	-	32,698,096	-	32,698,096
64	Meters	370	SD-1	WP 2.3 & 2.4	75,906,947	11,781,169	87,688,116	Distribution	-	-	87,688,116	-	87,688,116
65	Installation on Customers' Prem	371	SD-1		27,630		27,630	Distribution	-	-	27,630	-	27,630
66	Leased Property on Customers' Premises	372	SD-1		2,738,404		2,738,404	Distribution	-	-	2,738,404	-	2,738,404
67	Streetlighting & Signal Systems	373	SD-1		77,997,340		77,997,340	Distribution	-	-	77,997,340	-	77,997,340
68					$ 1,330,832,715	$ 11,726,701	$ 1,342,559,415		$ -	$ -	$ 1,342,559,415	$ -	$ 1,342,559,415
69													
70	**Subtotal Plant in Service Before General Plant**				**$ 3,607,082,765**	**$ 142,105,196**	**$ 3,749,187,961**		**$ 2,002,415,168**	**$ 404,213,378**	**$ 1,342,559,415**	**$ -**	**$ 3,749,187,961**
71													
72	General Plant												
73	Land & Land Rights	389	SD-1		$ 24,754,793		$ 24,754,793	SQFT	$ 10,776,642	$ 2,639,537	$ 9,536,230	$ 1,802,385	$ 24,754,793
74	Structures & Improvements	390	SD-1	WP 2.1	65,479,509	(6,672)	65,472,837	SQFT	28,502,655	6,981,191	25,221,944	4,767,047	65,472,837
75	Office Furniture & Equipment	391	SD-1	WP 2.1 & 2.3	71,900,419	34,813,044	106,713,463	ADJ Furniture	16,996,420	7,666,547	20,874,193	61,176,303	106,713,463
76	Transportation Equipment	392	SD-1	WP 2.1	26,923,502	(251)	26,923,251	392	1,849,619	9,154,894	15,918,737	-	26,923,251
77	Stores Equipment	393	SD-1	WP 2.1	620,372	(797)	619,575	PLTXGNL-N	321,151	75,935	222,489	-	619,575
78	Tools, Shop & Garage Equipment	394	SD-1		3,658,641		3,658,641	ADJ Trans Equip	334,174	448,403	2,876,064	-	3,658,641
79	Laboratory Equipment	395	SD-1		776,927		776,927	PLTXGNL-N	402,713	95,220	278,994	-	776,927
80	Power Operated Equipment	396	SD-1	WP 2.1	1,838,793	(2,396)	1,836,397	PLTXGNL-N	951,880	225,069	659,448	-	1,836,397
81	Communications Equipment	397	SD-1	WP 2.1	52,563,496	(233,118)	52,330,378	397	22,459,793	6,389,755	12,856,915	10,623,915	52,330,378
82	Miscellaneous Equipment	398	SD-1		280,205		280,205	PLTXGNL-N	145,242	34,342	100,621	-	280,205
83	Other Tangible Property	399	SD-1		-		-	PLTXGNL-N	-	-	-	-	-
84					$ 248,796,658	$ 34,569,810	$ 283,366,468		$ 82,740,289	$ 33,710,894	$ 88,545,635	$ 78,369,650	$ 283,366,468
85													
86	**Total Plant in Service - Gross**				**$ 3,855,879,423**	**$ 176,675,006**	**$ 4,032,554,429**		**$ 2,085,155,457**	**$ 437,924,271**	**$ 1,431,105,050**	**$ 78,369,650**	**$ 4,032,554,429**
87													
88													
89													
90	**Accumulated Depreciation**												
91	Intangible and Non-Utility Plant												
92	Organization Cost	301			$ -		$ -		$ -	$ -	$ -	$ -	$ -
93	Franchises and Consents	302			-		-		-	-	-	-	-
94	Intangible Plant	303			-		-		-	-	-	-	-
95	Non-Utility Plant	121	SD-1	WP 2.2	14,483,229	(14,483,229)	-		-	-	-	-	-
96					$ 14,483,229	$ (14,483,229)	$ -		$ -	$ -	$ -	$ -	$ -
97													
98	Steam Power Generation												
99	Land & Land Rights	310	SD-1		$ -		$ -	Production	$ -	$ -	$ -	$ -	$ -
100	Structures & Improvements	311	SD-1	WP 2.1 & 2.2	80,524,072	(3,551,973)	76,972,099	Production	76,972,099	-	-	-	76,972,099
101	Boiler Plant Equipment	312	SD-1	WP 2.1, 2.2 & 2.3	162,718,514	(5,161,006)	157,557,508	Production	157,557,508	-	-	-	157,557,508
102	Engines and Engine Driven Generators	313	SD-1		-		-	Production	-	-	-	-	-
103	Turbogenerator Units	314	SD-1	WP 2.1	57,493,272	(331,578)	57,161,693	Production	57,161,693	-	-	-	57,161,693
104	Accessory Plt Equipment	315	SD-1	WP 2.1 & 2.2	17,689,058	(617,597)	17,071,461	Production	17,071,461	-	-	-	17,071,461
105	Miscellaneous Equipment	316	SD-1	WP 2.1 & 2.2	51,522,775	(73,706)	51,449,069	Production	51,449,069	-	-	-	51,449,069
106					$ 369,947,690	$ (9,735,861)	$ 360,211,830		$ 360,211,830	$ -	$ -	$ -	$ 360,211,830
107													
108	Nuclear Power Generation												
109	Land & Land Rights	320	SD-1		$ -		$ -	Production	$ -	$ -	$ -	$ -	$ -
110	Structures & Improvements	321	SD-1		215,190,836		215,190,836	Production	215,190,836	-	-	-	215,190,836
111	Reactor Plant Equipment	322	SD-1	WP 2.1	141,797,817	(3,511,165)	138,286,653	Production	138,286,653	-	-	-	138,286,653
112	Turbogenerator Units	323	SD-1		17,624,900		17,624,900	Production	17,624,900	-	-	-	17,624,900
113	Accessory Plant Equipment	324	SD-1	WP 2.1	87,719,835	(109,012)	87,610,824	Production	87,610,824	-	-	-	87,610,824
114	Miscellaneous Equipment	325	SD-1	WP 2.1	3,757,495	(152,706)	3,604,788	Production	3,604,788	-	-	-	3,604,788

Work Paper 2 - Plant in Service

Purpose: Develop and Functionalize Plant in Service by FERC for the Test Year

Line No.		FERC Account	FY 2009 Source Reference	Adjustments Source Reference	FY 2009 Actual	Adjustments	Test Year	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A		B	C	D	E	F	G	H	I	J	K	L	M
115					$ 466,090,883	$ (3,772,882)	$ 462,318,000		$ 462,318,000	$ -	$ -	$ -	$ 462,318,000
116													
117	Combustion Turbine & Other Production												
118	Land & Land Rights	340	SD-1		$ -		$ -	Production	$ -	$ -	$ -	$ -	$ -
119	Structures & Improvements	341	SD-1	WP 2.2	951,325	(248,612)	702,713	Production	702,713	-	-	-	702,713
120	Fuel Holders, Producers and Accessories	342	SD-1		1,671,650		1,671,650	Production	1,671,650	-	-	-	1,671,650
121	Prime movers	343	SD-1		236,787		236,787	Production	236,787	-	-	-	236,787
122	Generator/PV	344	SD-1	WP 2.3	77,625,173	2,428,999	80,054,172	Production	80,054,172	-	-	-	80,054,172
123	Accessory Elec Equip.	345	SD-1		823,602		823,602	Production	823,602	-	-	-	823,602
124	Miscellaneous Equipment	346	SD-1		279,879		279,879	Production	279,879	-	-	-	279,879
125					$ 81,588,415	$ 2,180,387	$ 83,768,802		$ 83,768,802	$ -	$ -	$ -	$ 83,768,802
126													
127	**Total Power Generation Plant**				**$ 917,626,988**	**$ (11,328,356)**	**$ 906,298,632**		**$ 906,298,632**	**$ -**	**$ -**	**$ -**	**$ 906,298,632**
128													
129	Transmission Plant												
130	Land & Land Rights	350	SD-1	WP 2.1	$ -	-	$ -	Transmission	$ -	$ -	$ -	$ -	$ -
131	Clearing Land	351	SD-1		-		-	Transmission	-	-	-	-	-
132	Structures & Improvements	352	SD-1		7,673,215		7,673,215	Transmission	-	7,673,215	-	-	7,673,215
133	Station Equipment	353	SD-1	WP 2.1	43,789,277	(26,373)	43,762,905	Transmission	-	43,762,905	-	-	43,762,905
134	Towers and Fixtures	354	SD-1		29,260,913		29,260,913	Transmission	-	29,260,913	-	-	29,260,913
135	Poles and Fixtures	355	SD-1		20,902,393		20,902,393	Transmission	-	20,902,393	-	-	20,902,393
136	Overhead Conductors and Devices	356	SD-1		40,591,204		40,591,204	Transmission	-	40,591,204	-	-	40,591,204
137	Underground Conduit	357	SD-1		1,104,755		1,104,755	Transmission	-	1,104,755	-	-	1,104,755
138	Underground Conductors and Devices	358	SD-1		1,500,483		1,500,483	Transmission	-	1,500,483	-	-	1,500,483
139	Roads and Trails	359	SD-1		244,426		244,426	Transmission	-	244,426	-	-	244,426
140					$ 145,066,665	$ (26,373)	$ 145,040,292		$ -	$ 145,040,292	$ -	$ -	$ 145,040,292
141													
142	Distribution Plant												
143	Land & Land Rights	360	SD-1		$ -		$ -	Distribution	$ -	$ -	$ -	$ -	$ -
144	Structures & Improvements	361	SD-1		13,004,074		13,004,074	Distribution	-	-	13,004,074	-	13,004,074
145	Station Equipment	362	SD-1	WP 2.1	57,606,294	(11,780)	57,594,514	Distribution	-	-	57,594,514	-	57,594,514
146	Storage Equipment	363	SD-1		18,488		18,488	Distribution	-	-	18,488	-	18,488
147	Poles, Towers & Fixtures	364	SD-1		73,689,580		73,689,580	Distribution	-	-	73,689,580	-	73,689,580
148	OH Conductors & Devices	365	SD-1		79,070,916		79,070,916	Distribution	-	-	79,070,916	-	79,070,916
149	UG Conduit	366	SD-1		80,139,771		80,139,771	Distribution	-	-	80,139,771	-	80,139,771
150	UG Conductors & Devices	367	SD-1		101,929,307		101,929,307	Distribution	-	-	101,929,307	-	101,929,307
151	Line Transformers	368	SD-1		87,000,937		87,000,937	Distribution	-	-	87,000,937	-	87,000,937
152	Services	369	SD-1		23,989,499		23,989,499	Distribution	-	-	23,989,499	-	23,989,499
153	Meters	370	SD-1	WP 2.3 & 2.4	36,117,322	(5,183,095)	30,934,227	Distribution	-	-	30,934,227	-	30,934,227
154	Installation on Customers' Prem	371	SD-1		8,347		8,347	Distribution	-	-	8,347	-	8,347
155	Leased Property on Customers' Premises	372	SD-1		2,060,517		2,060,517	Distribution	-	-	2,060,517	-	2,060,517
156	Streetlighting & Signal Systems	373	SD-1		33,746,289		33,746,289	Distribution	-	-	33,746,289	-	33,746,289
157					$ 588,381,340	$ (5,194,875)	$ 583,186,465		$ -	$ -	$ 583,186,465	$ -	$ 583,186,465
158													
159	**Subtotal Plant in Service Before General Plant**				**$ 1,665,558,222**	**$ (31,032,832)**	**$ 1,634,525,389**		**$ 906,298,632**	**$ 145,040,292**	**$ 583,186,465**	**$ -**	**$ 1,634,525,389**
160													
161	General Plant												
162	Land & Land Rights	389	SD-1		$ -		$ -	SQFT	$ -	$ -	$ -	$ -	$ -
163	Structures & Improvements	390	SD-1	WP 2.1	33,963,045	(6,357)	33,956,688	SQFT	14,782,554	3,620,710	13,081,053	2,472,371	33,956,688
164	Office Furniture & Equipment	391	SD-1	WP 2.1 & 2.3	39,292,313	2,892,351	42,184,664	ADJ Furniture	6,718,817	3,030,646	8,251,731	24,183,470	42,184,664
165	Transportation Equipment	392	SD-1	WP 2.1	15,921,740	(170)	15,921,569	392	1,093,807	5,413,918	9,413,844	-	15,921,569
166	Stores Equipment	393	SD-1	WP 2.1	610,582	(796)	609,786	PLTXGNL-N	316,077	74,735	218,973	-	609,786
167	Tools, Shop & Garage Equipment	394	SD-1		1,689,372		1,689,372	ADJ Trans Equip	154,304	207,050	1,328,019	-	1,689,372
168	Laboratory Equipment	395	SD-1		415,636		415,636	PLTXGNL-N	215,441	50,940	149,255	-	415,636
169	Power Operated Equipment	396	SD-1	WP 2.1	341,756	(2,396)	339,360	PLTXGNL-N	175,904	41,592	121,864	-	339,360
170	Communications Equipment	397	SD-1	WP 2.1	39,996,641	(179,953)	39,816,688	397	17,089,014	4,861,782	9,782,459	8,083,433	39,816,688
171	Miscellaneous Equipment	398	SD-1		192,019		192,019	PLTXGNL-N	99,532	23,534	68,954	-	192,019

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Purpose: Develop and Functionalize Plant in Service by FERC for the Test Year

Line No.		FERC Account	FY 2009 Source Reference	Adjustments Source Reference	FY 2009 Actual	Adjustments	Test Year	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A		B	C	D	E	F	G	H	I	J	K	L	M
172	Other Tangible Property	399	SD-1		-		-	PLTXGNL-N	-	-	-	-	-
173					$ 132,423,105	$ 2,702,678	$ 135,125,783		$ 40,645,451	$ 17,324,907	$ 42,416,152	$ 34,739,274	$ 135,125,783
174													
175	**Total Plant in Service - Accumulated Depreciation**				**$ 1,797,981,327**	**$ (28,330,154)**	**$ 1,769,651,173**		**$ 946,944,083**	**$ 162,365,199**	**$ 625,602,617**	**$ 34,739,274**	**$ 1,769,651,173**
176													
177													
178													
179	**Net Plant In Service**												
180	Intangible and Non-Utility Plant												
181	Organization Cost	301			$ -		$ -		$ -	$ -	$ -	$ -	$ -
182	Franchises and Consents	302			-		-		-	-	-	-	-
183	Intangible Plant	303			-		-		-	-	-	-	-
184	Non-Utility Plant	121			100,940,109	(100,940,109)	-		-	-	-	-	-
185					$ 100,940,109	$ (100,940,109)	$ -		$ -	$ -	$ -	$ -	$ -
186													
187	Steam Power Generation												
188	Land & Land Rights	310			$ 9,234,828		$ 9,234,828	Production	$ 9,234,828	$ -	$ -	$ -	$ 9,234,828
189	Structures & Improvements	311			13,870,865	(1,394,220)	12,476,645	Production	12,476,645	-	-	-	12,476,645
190	Boiler Plant Equipment	312			61,821,962	192,456,181	254,278,143	Production	254,278,143	-	-	-	254,278,143
191	Engines and Engine Driven Generators	313			-		-	Production	-	-	-	-	-
192	Turbogenerator Units	314			18,656,660	(160,538)	18,496,121	Production	18,496,121	-	-	-	18,496,121
193	Accessory Plt Equipment	315			13,770,252	(126,651)	13,643,601	Production	13,643,601	-	-	-	13,643,601
194	Miscellaneous Equipment	316			11,328,455	(14,413)	11,314,042	Production	11,314,042	-	-	-	11,314,042
195					$ 128,683,021	$ 190,760,359	$ 319,443,380		$ 319,443,380	$ -	$ -	$ -	$ 319,443,380
196													
197	Nuclear Power Generation												
198	Land & Land Rights	320			$ 2,782,002		$ 2,782,002	Production	$ 2,782,002	$ -	$ -	$ -	$ 2,782,002
199	Structures & Improvements	321			191,529,059		191,529,059	Production	191,529,059	-	-	-	191,529,059
200	Reactor Plant Equipment	322			158,341,750	(3,118,595)	155,223,155	Production	155,223,155	-	-	-	155,223,155
201	Turbogenerator Units	323			30,766,875		30,766,875	Production	30,766,875	-	-	-	30,766,875
202	Accessory Plant Equipment	324			79,083,354	(98,028)	78,985,326	Production	78,985,326	-	-	-	78,985,326
203	Miscellaneous Equipment	325			5,297,244	(247,769)	5,049,475	Production	5,049,475	-	-	-	5,049,475
204					$ 467,800,284	$ (3,464,393)	$ 464,335,891		$ 464,335,891	$ -	$ -	$ -	$ 464,335,891
205													
206	Combustion Turbine & Other Production												
207	Land & Land Rights	340			$ 32,120		$ 32,120	Production	$ 32,120	$ -	$ -	$ -	$ 32,120
208	Structures & Improvements	341			6,483,796	(448,452)	6,035,344	Production	6,035,344	-	-	-	6,035,344
209	Fuel Holders, Producers and Accessories	342			8,701,949		8,701,949	Production	8,701,949	-	-	-	8,701,949
210	Prime movers	343			953,520		953,520	Production	953,520	-	-	-	953,520
211	Generator/PV	344			222,000,238	70,440,958	292,441,196	Production	292,441,196	-	-	-	292,441,196
212	Accessory Elec Equip.	345			2,338,570		2,338,570	Production	2,338,570	-	-	-	2,338,570
213	Miscellaneous Equipment	346			1,834,565		1,834,565	Production	1,834,565	-	-	-	1,834,565
214					$ 242,344,758	$ 69,992,506	$ 312,337,264		$ 312,337,264	$ -	$ -	$ -	$ 312,337,264
215													
216	**Total Power Generation Plant**				**$ 838,828,064**	**$ 257,288,471**	**$ 1,096,116,536**		**$ 1,096,116,536**	**$ -**	**$ -**	**$ -**	**$ 1,096,116,536**
217													
218	Transmission Plant												
219	Land & Land Rights	350			$ 20,741,288	$ (1,188)	$ 20,740,100	Transmission	$ -	$ 20,740,100	$ -	$ -	$ 20,740,100
220	Clearing Land	351			-		-	Transmission	-	-	-	-	-
221	Structures & Improvements	352			15,731,423		15,731,423	Transmission	-	15,731,423	-	-	15,731,423
222	Station Equipment	353			115,101,303	(130,722)	114,970,581	Transmission	-	114,970,581	-	-	114,970,581
223	Towers and Fixtures	354			14,333,822		14,333,822	Transmission	-	14,333,822	-	-	14,333,822
224	Poles and Fixtures	355			39,405,304		39,405,304	Transmission	-	39,405,304	-	-	39,405,304
225	Overhead Conductors and Devices	356			42,965,890		42,965,890	Transmission	-	42,965,890	-	-	42,965,890
226	Underground Conduit	357			3,840,659		3,840,659	Transmission	-	3,840,659	-	-	3,840,659
227	Underground Conductors and Devices	358			6,575,612		6,575,612	Transmission	-	6,575,612	-	-	6,575,612
228	Roads and Trails	359			609,695		609,695	Transmission	-	609,695	-	-	609,695

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Line No.		FERC Account	FY 2009 Source Reference	Adjustments Source Reference	FY 2009 Actual	Adjustments	Test Year	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A		B	C	D	E	F	G	H	I	J	K	L	M
229					$ 259,304,995	$ (131,909)	$ 259,173,086		$ -	$ 259,173,086	$ -	$ -	$ 259,173,086
230													
231	Distribution Plant												
232	Land & Land Rights	360			$ 6,461,585		$ 6,461,585	Distribution	$ -	$ -	$ 6,461,585	$ -	$ 6,461,585
233	Structures & Improvements	361			15,299,198		15,299,198	Distribution	-	-	15,299,198	-	15,299,198
234	Station Equipment	362			117,529,064	(42,689)	117,486,376	Distribution	-	-	117,486,376	-	117,486,376
235	Storage Equipment	363			18,407		18,407	Distribution	-	-	18,407	-	18,407
236	Poles, Towers & Fixtures	364			83,445,095		83,445,095	Distribution	-	-	83,445,095	-	83,445,095
237	OH Conductors & Devices	365			101,397,503		101,397,503	Distribution	-	-	101,397,503	-	101,397,503
238	UG Conduit	366			69,971,100		69,971,100	Distribution	-	-	69,971,100	-	69,971,100
239	UG Conductors & Devices	367			139,689,403		139,689,403	Distribution	-	-	139,689,403	-	139,689,403
240	Line Transformers	368			115,193,576		115,193,576	Distribution	-	-	115,193,576	-	115,193,576
241	Services	369			8,708,597		8,708,597	Distribution	-	-	8,708,597	-	8,708,597
242	Meters	370			39,789,625	16,964,264	56,753,889	Distribution	-	-	56,753,889	-	56,753,889
243	Installation on Customers' Prem	371			19,283		19,283	Distribution	-	-	19,283	-	19,283
244	Leased Property on Customers' Premises	372			677,887		677,887	Distribution	-	-	677,887	-	677,887
245	Streetlighting & Signal Systems	373			44,251,052		44,251,052	Distribution	-	-	44,251,052	-	44,251,052
246					$ 742,451,375	$ 16,921,575	$ 759,372,950		$ -	$ -	$ 759,372,950	$ -	$ 759,372,950
247													
248	**Subtotal Plant in Service Before General Plant**				**$ 1,941,524,543**	**$ 173,138,028**	**$ 2,114,662,571**		**$ 1,096,116,536**	**$ 259,173,086**	**$ 759,372,950**	**$ -**	**$ 2,114,662,571**
249													
250	General Plant												
251	Land & Land Rights	389			$ 24,754,793		$ 24,754,793	SQFT	$ 10,776,642	$ 2,639,537	$ 9,536,230	$ 1,802,385	$ 24,754,793
252	Structures & Improvements	390			31,516,464	(315)	31,516,149	SQFT	13,720,101	3,360,482	12,140,891	2,294,676	31,516,149
253	Office Furniture & Equipment	391			32,608,106	31,920,693	64,528,799	ADJ Furniture	10,277,603	4,635,901	12,622,462	36,992,834	64,528,799
254	Transportation Equipment	392			11,001,762	(81)	11,001,681	392	755,812	3,740,976	6,504,893	-	11,001,681
255	Stores Equipment	393			9,790	(1)	9,789	PLTXGNL-N	5,074	1,200	3,515	-	9,789
256	Tools, Shop & Garage Equipment	394			1,969,268		1,969,268	ADJ Trans Equip	179,869	241,354	1,548,045	-	1,969,268
257	Laboratory Equipment	395			361,291		361,291	PLTXGNL-N	187,272	44,280	129,739	-	361,291
258	Power Operated Equipment	396			1,497,037		1,497,037	PLTXGNL-N	775,976	183,477	537,584	-	1,497,037
259	Communications Equipment	397			12,566,855	(53,165)	12,513,690	397	5,370,779	1,527,973	3,074,456	2,540,482	12,513,690
260	Miscellaneous Equipment	398			88,186		88,186	PLTXGNL-N	45,710	10,808	31,668	-	88,186
261	Other Tangible Property	399			-		-	PLTXGNL-N	-	-	-	-	-
262					$ 116,373,553	$ 31,867,132	$ 148,240,685		$ 42,094,838	$ 16,385,987	$ 46,129,483	$ 43,630,377	$ 148,240,685
263													
264	**Total Plant in Service - Net**				**$ 2,057,898,095**	**$ 205,005,161**	**$ 2,262,903,256**		**$ 1,138,211,374**	**$ 275,559,073**	**$ 805,502,433**	**$ 43,630,377**	**$ 2,262,903,256**
265													
266													
267													
268	**Depreciation Expense**												
269	Intangible and Non-Utility Plant												
270	Organization Cost	301			$ -		$ -		$ -	$ -	$ -	$ -	$ -
271	Franchises and Consents	302			-		-		-	-	-	-	-
272	Intangible Plant	303			-		-		-	-	-	-	-
273	Non-Utility Plant	121	SD-1	WP 2.2	3,619,223	(3,619,223)	-		-	-	-	-	-
274					$ 3,619,223	$ (3,619,223)	$ -		$ -	$ -	$ -	$ -	$ -
275													
276	Steam Power Generation												
277	Land & Land Rights	310	SD-1		$ -		$ -	Production	$ -	$ -	$ -	$ -	$ -
278	Structures & Improvements	311	SD-1	WP 2.1 & 2.2	2,560,843	(116,532)	2,444,311	Production	2,444,311	-	-	-	2,444,311
279	Boiler Plant Equipment	312	SD-1	WP 2.1, 2.2 & 2.3	6,066,242	6,323,235	12,389,477	Production	12,389,477	-	-	-	12,389,477
280	Engines and Engine Driven Generators	313	SD-1		-		-	Production	-	-	-	-	-
281	Turbogenerator Units	314	SD-1	WP 2.1	2,055,534	(13,284)	2,042,250	Production	2,042,250	-	-	-	2,042,250
282	Accessory Plt Equipment	315	SD-1	WP 2.1 & 2.2	849,580	(18,961)	830,619	Production	830,619	-	-	-	830,619
283	Miscellaneous Equipment	316	SD-1	WP 2.1 & 2.2	1,708,115	(7,024)	1,701,091	Production	1,701,091	-	-	-	1,701,091
284					$ 13,240,315	$ 6,167,434	$ 19,407,749		$ 19,407,749	$ -	$ -	$ -	$ 19,407,749
285													

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A		B	C	D	E	F	G	H	I	J	K	L	M
286	Nuclear Power Generation												
287	Land & Land Rights	320	SD-1		$ -		$ -	Production	$ -	$ -	$ -	$ -	$ -
288	Structures & Improvements	321	SD-1		9,634,365		9,634,365	Production	9,634,365	-	-	-	9,634,365
289	Reactor Plant Equipment	322	SD-1	WP 2.1	7,109,694	(157,045)	6,952,649	Production	6,952,649	-	-	-	6,952,649
290	Turbogenerator Units	323	SD-1		4,126,237		4,126,237	Production	4,126,237	-	-	-	4,126,237
291	Accessory Plant Equipment	324	SD-1	WP 2.1	3,951,227	(4,904)	3,946,323	Production	3,946,323	-	-	-	3,946,323
292	Miscellaneous Equipment	325	SD-1	WP 2.1	214,488	(9,486)	205,002	Production	205,002	-	-	-	205,002
293					$ 25,036,012	$ (171,436)	$ 24,864,576		$ 24,864,576	$ -	$ -	$ -	$ 24,864,576
294													
295	Combustion Turbine & Other Production												
296	Land & Land Rights	340	SD-1		$ -		$ -	Production	$ -	$ -	$ -	$ -	$ -
297	Structures & Improvements	341	SD-1	WP 2.2	242,540	(22,615)	219,925	Production	219,925	-	-	-	219,925
298	Fuel Holders, Producers and Accessories	342	SD-1		337,791		337,791	Production	337,791	-	-	-	337,791
299	Prime movers	343	SD-1		38,618		38,618	Production	38,618	-	-	-	38,618
300	Generator/PV	344	SD-1	WP 2.3	9,720,944	2,428,999	12,149,942	Production	12,149,942	-	-	-	12,149,942
301	Accessory Elec Equip.	345	SD-1		103,035		103,035	Production	103,035	-	-	-	103,035
302	Miscellaneous Equipment	346	SD-1		71,884		71,884	Production	71,884	-	-	-	71,884
303					$ 10,514,811	$ 2,406,383	$ 12,921,195		$ 12,921,195	$ -	$ -	$ -	$ 12,921,195
304													
305	**Total Power Generation Plant**				**$ 48,791,138**	**$ 8,402,381**	**$ 57,193,519**		**$ 57,193,519**	**$ -**	**$ -**	**$ -**	**$ 57,193,519**
306													
307	Transmission Plant												
308	Land & Land Rights	350	SD-1	WP 2.1	$ -	-	$ -	Transmission	$ -	$ -	$ -	$ -	$ -
309	Clearing Land	351	SD-1		-		-	Transmission	-	-	-	-	-
310	Structures & Improvements	352	SD-1		793,273		793,273	Transmission	-	793,273	-	-	793,273
311	Station Equipment	353	SD-1	WP 2.1	3,928,621	(3,884)	3,924,737	Transmission	-	3,924,737	-	-	3,924,737
312	Towers and Fixtures	354	SD-1		1,354,543		1,354,543	Transmission	-	1,354,543	-	-	1,354,543
313	Poles and Fixtures	355	SD-1		1,955,012		1,955,012	Transmission	-	1,955,012	-	-	1,955,012
314	Overhead Conductors and Devices	356	SD-1		2,682,983		2,682,983	Transmission	-	2,682,983	-	-	2,682,983
315	Underground Conduit	357	SD-1		161,069		161,069	Transmission	-	161,069	-	-	161,069
316	Underground Conductors and Devices	358	SD-1		256,552		256,552	Transmission	-	256,552	-	-	256,552
317	Roads and Trails	359	SD-1		22,607		22,607	Transmission	-	22,607	-	-	22,607
318					$ 11,154,660	$ (3,884)	$ 11,150,776		$ -	$ 11,150,776	$ -	$ -	$ 11,150,776
319													
320	Distribution Plant												
321	Land & Land Rights	360	SD-1		$ -		$ -	Distribution	$ -	$ -	$ -	$ -	$ -
322	Structures & Improvements	361	SD-1		993,226		993,226	Distribution	-	-	993,226	-	993,226
323	Station Equipment	362	SD-1	WP 2.1	4,140,544	(1,288)	4,139,256	Distribution	-	-	4,139,256	-	4,139,256
324	Storage Equipment	363	SD-1		3,244		3,244	Distribution	-	-	3,244	-	3,244
325	Poles, Towers & Fixtures	364	SD-1		4,601,750		4,601,750	Distribution	-	-	4,601,750	-	4,601,750
326	OH Conductors & Devices	365	SD-1		5,049,315		5,049,315	Distribution	-	-	5,049,315	-	5,049,315
327	UG Conduit	366	SD-1		4,487,640		4,487,640	Distribution	-	-	4,487,640	-	4,487,640
328	UG Conductors & Devices	367	SD-1		7,152,122		7,152,122	Distribution	-	-	7,152,122	-	7,152,122
329	Line Transformers	368	SD-1		5,218,083		5,218,083	Distribution	-	-	5,218,083	-	5,218,083
330	Services	369	SD-1		976,365		976,365	Distribution	-	-	976,365	-	976,365
331	Meters	370	SD-1	WP 2.3 & 2.4	2,520,883	559,340	3,080,223	Distribution	-	-	3,080,223	-	3,080,223
332	Installation on Customers' Prem	371	SD-1		1,829		1,829	Distribution	-	-	1,829	-	1,829
333	Leased Property on Customers' Premises	372	SD-1		78,293		78,293	Distribution	-	-	78,293	-	78,293
334	Streetlighting & Signal Systems	373	SD-1		2,081,101		2,081,101	Distribution	-	-	2,081,101	-	2,081,101
335					$ 37,304,394	$ 558,052	$ 37,862,447		$ -	$ -	$ 37,862,447	$ -	$ 37,862,447
336													
337	**Subtotal Plant in Service Before General Plant**				**$ 100,869,415**	**$ 5,337,326**	**$ 106,206,742**		**$ 57,193,519**	**$ 11,150,776**	**$ 37,862,447**	**$ -**	**$ 106,206,742**
338													
339	General Plant												
340	Land & Land Rights	389	SD-1		$ -		$ -	SQFT	$ -	$ -	$ -	$ -	$ -
341	Structures & Improvements	390	SD-1	WP 2.1	1,794,044	(183)	1,793,861	SQFT	780,932	191,275	691,045	130,610	1,793,861
342	Office Furniture & Equipment	391	SD-1	WP 2.1 & 2.3	5,866,086	2,901,104	8,767,189	ADJ Furniture	1,396,364	629,856	1,714,948	5,026,022	8,767,189

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A		B	C	D	E	F	G	H	I	J	K	L	M
343	Transportation Equipment	392	SD-1	WP 2.1	2,004,818	(19)	2,004,799	392	137,729	681,705	1,185,365	-	2,004,799
344	Stores Equipment	393	SD-1	WP 2.1	692	(1)	692	PLTXGNL-N	358	85	248	-	692
345	Tools, Shop & Garage Equipment	394	SD-1		243,025		243,025	ADJ Trans Equip	22,197	29,785	191,042	-	243,025
346	Laboratory Equipment	395	SD-1		60,341		60,341	PLTXGNL-N	31,277	7,395	21,668	-	60,341
347	Power Operated Equipment	396	SD-1	WP 2.1	35,982	(47)	35,935	PLTXGNL-N	18,627	4,404	12,904	-	35,935
348	Communications Equipment	397	SD-1	WP 2.1	3,282,761	(14,559)	3,268,202	397	1,402,687	399,061	802,956	663,498	3,268,202
349	Miscellaneous Equipment	398	SD-1		14,557		14,557	PLTXGNL-N	7,545	1,784	5,227	-	14,557
350	Other Tangible Property	399	SD-1		-		-	PLTXGNL-N	-	-	-	-	-
351					$ 13,302,306	$ 2,886,295	$ 16,188,601		$ 3,797,717	$ 1,945,350	$ 4,625,404	$ 5,820,130	$ 16,188,601
352													
353	**Total Plant Depreciation**				**$ 114,171,721**	**$ 8,223,622**	**$ 122,395,343**		**$ 60,991,236**	**$ 13,096,126**	**$ 42,487,850**	**$ 5,820,130**	**$ 122,395,343**

Work Paper 2.1 - Plant in Service
Purpose: Identify FY 2010 Retirements from Plant in Service

Line No.		FERC Account	FY 2009 Source Reference	Retirements Source Reference	FY 2009 Actual	Retirements	Test Year
A		B	C	D	E	F	G
1	**Original Cost of Plant In Service**						
2	Steam Power Generation						
3	Structures & Improvements	311	SD-1	SD-4	$ 94,394,936	$ (3,516,671)	$ 90,878,265
4	Boiler Plant Equipment	312	SD-1	SD-4	224,540,476	(12,598,880)	211,941,596
5	Turbogenerator Units	314	SD-1	SD-4	76,149,931	(492,117)	75,657,814
6	Accessory Plt Equipment	315	SD-1	SD-4	31,459,310	(411,895)	31,047,415
7	Miscellaneous Equipment	316	SD-1	SD-4	62,851,230	(13,372)	62,837,858
8					$ 489,395,884	$ (17,032,935)	$ 472,362,948
9							
10	Nuclear Power Generation						
11	Reactor Plant Equipment	322	SD-1	SD-4	$ 300,139,567	$ (6,629,760)	$ 293,509,807
12	Accessory Plant Equipment	324	SD-1	SD-4	166,803,189	(207,040)	166,596,149
13	Miscellaneous Equipment	325	SD-1	SD-4	9,054,739	(400,476)	8,654,263
14					$ 475,997,495	$ (7,237,276)	$ 468,760,219
15							
16	Transmission Plant						
17	Land & Land Rights	350	SD-1	SD-4	$ 20,741,288	$ (1,188)	$ 20,740,100
18	Station Equipment	353	SD-1	SD-4	158,890,580	(157,095)	158,733,486
19					$ 179,631,868	$ (158,282)	$ 179,473,586
20							
21	Distribution Plant						
22	Station Equipment	362	SD-1	SD-4	$ 175,135,358	$ (54,469)	$ 175,080,889
23							
24	General Plant						
25	Structures & Improvements	390	SD-1	SD-4	$ 65,479,509	$ (6,672)	$ 65,472,837
26	Office Furniture & Equipment	391	SD-1	SD-4	71,900,419	(9,531)	71,890,889
27	Transportation Equipment	392	SD-1	SD-4	26,923,502	(251)	26,923,251
28	Stores Equipment	393	SD-1	SD-4	620,372	(797)	619,575
29	Power Operated Equipment	396	SD-1	SD-4	1,838,793	(2,396)	1,836,397
30	Communications Equipment	397	SD-1	SD-4	52,563,496	(233,118)	52,330,378
31					$ 219,326,091	$ (252,764)	$ 219,073,327
32							
33					$ 1,539,486,697	$ (24,735,726)	$ 1,514,750,970
34							
35	**Accumulated Depreciation [1]**						
36	Steam Power Generation						
37	Structures & Improvements	311	SD-1	SD-4	$ 80,524,072	$ (1,989,484)	$ 78,534,588
38	Boiler Plant Equipment	312	SD-1	SD-4	162,718,514	(11,739,127)	150,979,387
39	Turbogenerator Units	314	SD-1	SD-4	57,493,272	(331,578)	57,161,693
40	Accessory Plt Equipment	315	SD-1	SD-4	17,689,058	(290,859)	17,398,199
41	Miscellaneous Equipment	316	SD-1	SD-4	51,522,775	(13,372)	51,509,402
42					$ 369,947,690	$ (14,364,421)	$ 355,583,270
43							
44	Nuclear Power Generation						
45	Reactor Plant Equipment	322	SD-1	SD-4	$ 141,797,817	$ (3,511,165)	$ 138,286,653
46	Accessory Plant Equipment	324	SD-1	SD-4	87,719,835	(109,012)	87,610,824
47	Miscellaneous Equipment	325	SD-1	SD-4	3,757,495	(152,706)	3,604,788
48					$ 233,275,147	$ (3,772,882)	$ 229,502,264
49							
50	Transmission Plant						
51	Land & Land Rights	350	SD-1	SD-4	$ -	$ -	$ -
52	Station Equipment	353	SD-1	SD-4	43,789,277	(26,373)	43,762,905
53					$ 43,789,277	$ (26,373)	$ 43,762,905
54							
55	Distribution Plant						
56	Station Equipment	362	SD-1	SD-4	$ 57,606,294	$ (11,780)	$ 57,594,514
57							
58	General Plant						
59	Structures & Improvements	390	SD-1	SD-4	$ 33,963,045	$ (6,357)	$ 33,956,688
60	Office Furniture & Equipment	391	SD-1	SD-4	39,292,313	(9,531)	39,282,783
61	Transportation Equipment	392	SD-1	SD-4	15,921,740	(170)	15,921,569
62	Stores Equipment	393	SD-1	SD-4	610,582	(796)	609,786
63	Power Operated Equipment	396	SD-1	SD-4	341,756	(2,396)	339,360
64	Communications Equipment	397	SD-1	SD-4	39,996,641	(179,953)	39,816,688
65					$ 130,126,077	$ (199,203)	$ 129,926,874
66							
67					$ 834,744,486	$ (18,374,659)	$ 816,369,827
68							

Work Paper 2.1 - Plant in Service
Purpose: Identify FY 2010 Retirements from Plant in Service

Line No.		FERC Account	FY 2009 Source Reference	Retirements Source Reference		FY 2009 Actual		Retirements		Test Year
A		B	C	D		E		F		G
69	**Net Plant In Service**									
70	Steam Power Generation									
71	Structures & Improvements	311			$	13,870,865	$	(1,527,187)	$	12,343,677
72	Boiler Plant Equipment	312				61,821,962		(859,753)		60,962,209
73	Turbogenerator Units	314				18,656,660		(160,538)		18,496,121
74	Accessory Plt Equipment	315				13,770,252		(121,036)		13,649,216
75	Miscellaneous Equipment	316				11,328,455		-		11,328,455
76					$	119,448,194	$	(2,668,515)	$	116,779,679
77										
78	Nuclear Power Generation									
79	Reactor Plant Equipment	322			$	158,341,750	$	(3,118,595)	$	155,223,155
80	Accessory Plant Equipment	324				79,083,354		(98,028)		78,985,326
81	Miscellaneous Equipment	325				5,297,244		(247,769)		5,049,475
82					$	242,722,348	$	(3,464,393)	$	239,257,955
83										
84	Transmission Plant									
85	Land & Land Rights	350			$	20,741,288	$	(1,188)	$	20,740,100
86	Station Equipment	353				115,101,303		(130,722)		114,970,581
87					$	135,842,591	$	(131,909)	$	135,710,681
88										
89	Distribution Plant									
90	Station Equipment	362			$	117,529,064	$	(42,689)	$	117,486,376
91										
92	General Plant									
93	Structures & Improvements	390			$	31,516,464	$	(315)	$	31,516,149
94	Office Furniture & Equipment	391				32,608,106		-		32,608,106
95	Transportation Equipment	392				11,001,762		(81)		11,001,681
96	Stores Equipment	393				9,790		(1)		9,789
97	Power Operated Equipment	396				1,497,037		-		1,497,037
98	Communications Equipment	397				12,566,855		(53,165)		12,513,690
99					$	89,200,014	$	(53,561)	$	89,146,453
100										
101					$	704,742,211	$	(6,361,067)	$	698,381,144
102										
103	**Depreciation Expense**									
104	Steam Power Generation									
105	Structures & Improvements	311	SD-1	SD-4	$	2,560,843	$	(95,314)	$	2,465,529
106	Boiler Plant Equipment	312	SD-1	SD-4		6,066,242		(340,444)		5,725,798
107	Turbogenerator Units	314	SD-1	SD-4		2,055,534		(13,284)		2,042,250
108	Accessory Plt Equipment	315	SD-1	SD-4		849,580		(11,125)		838,455
109	Miscellaneous Equipment	316	SD-1	SD-4		1,708,115		(363)		1,707,752
110					$	13,240,315	$	(460,530)	$	12,779,785
111										
112	Nuclear Power Generation									
113	Reactor Plant Equipment	322	SD-1	SD-4	$	7,109,694	$	(157,045)	$	6,952,649
114	Accessory Plant Equipment	324	SD-1	SD-4		3,951,227		(4,904)		3,946,323
115	Miscellaneous Equipment	325	SD-1	SD-4		214,488		(9,486)		205,002
116					$	11,275,410	$	(171,436)	$	11,103,974
117										
118	Transmission Plant									
119	Land & Land Rights	350	SD-1	SD-4	$	-	$	-	$	-
120	Station Equipment	353	SD-1	SD-4		3,928,621		(3,884)		3,924,737
121					$	3,928,621	$	(3,884)	$	3,924,737
122										
123	Distribution Plant									
124	Station Equipment	362	SD-1	SD-4	$	4,140,544	$	(1,288)	$	4,139,256
125										
126	General Plant									
127	Structures & Improvements	390	SD-1	SD-4	$	1,794,044	$	(183)	$	1,793,861
128	Office Furniture & Equipment	391	SD-1	SD-4		5,866,086		(778)		5,865,308
129	Transportation Equipment	392	SD-1	SD-4		2,004,818		(19)		2,004,799
130	Stores Equipment	393	SD-1	SD-4		692		(1)		692
131	Power Operated Equipment	396	SD-1	SD-4		35,982		(47)		35,935
132	Communications Equipment	397	SD-1	SD-4		3,282,761		(14,559)		3,268,202
133					$	12,984,383	$	(15,586)	$	12,968,798
134										
135					$	45,569,273	$	(652,724)	$	44,916,549
136										
137	Notes:									
138	[1] Accumulated depreciation retirements are reflective of FY 2009 amounts									

Work Paper 2.2 - Plant in Service

Purpose: Identify Non-Electric Utility Plant in Service for Removal from Test Year

Line No.		FERC Account	FY 2009 Source Reference	FY 2009 Actual	Adjustments	Test Year
A		B	C	D	E	F
1	**Original Cost of Plant In Service**					
2	Intangible and Non-Utility Plant					
3	Non-Utility Plant	121	SD-1	$ 115,423,338	$ (115,423,338)	$ -
4	Holly Power Plant [1]					
5	Structures & Improvements	311	SD-72	$ 1,429,522	$ (1,429,522)	$ -
6	Boiler Plant Equipment	312	SD-72	86,111	(86,111)	-
7	Accessory Plt Equipment	315	SD-72	332,354	(332,354)	-
8	Miscellaneous Equipment	316	SD-72	74,747	(74,747)	-
9	Structures & Improvements	341	SD-72	697,064	(697,064)	-
10				$ 2,619,796	$ (2,619,796)	$ -
11						
12				$ 118,043,134	$ (118,043,134)	$ -
13						
14	**Accumulated Depreciation**					
15	Intangible and Non-Utility Plant					
16	Non-Utility Plant	121	SD-1	$ 14,483,229	$ (14,483,229)	$ -
17	Holly Power Plant [1]					
18	Structures & Improvements	311	SD-72	$ 1,562,489	$ (1,562,489)	$ -
19	Boiler Plant Equipment	312	SD-72	87,885	(87,885)	-
20	Accessory Plt Equipment	315	SD-72	326,738	(326,738)	-
21	Miscellaneous Equipment	316	SD-72	60,333	(60,333)	-
22	Structures & Improvements	341	SD-72	248,612	(248,612)	-
23				$ 2,286,057	$ (2,286,057)	$ -
24						
25				$ 16,769,286	$ (16,769,286)	$ -
26						
27	**Net Plant In Service**					
28	Intangible and Non-Utility Plant					
29	Non-Utility Plant	121		$ 100,940,109	$ (100,940,109)	$ -
30	Holly Power Plant [1]					
31	Structures & Improvements	311		$ (132,968)	$ 132,968	$ -
32	Boiler Plant Equipment	312		(1,774)	1,774	-
33	Accessory Plt Equipment	315		5,615	(5,615)	-
34	Miscellaneous Equipment	316		14,413	(14,413)	-
35	Structures & Improvements	341		448,452	(448,452)	-
36				$ 333,739	$ (333,739)	$ -
37						
38				$ 101,273,848	$ (101,273,848)	$ -
39						

Work Paper 2.2 - Plant in Service

Purpose: Identify Non-Electric Utility Plant in Service for Removal from Test Year

Line No.		FERC Account	FY 2009 Source Reference	FY 2009 Actual	Adjustments	Test Year
A		B	C	D	E	F
40	**Depreciation Expense**					
41	Intangible and Non-Utility Plant					
42	Non-Utility Plant	121	SD-1	$ 3,619,223	$ (3,619,223)	$ -
43	Holly Power Plant [1]					
44	Structures & Improvements	311	SD-72	$ 21,218	$ (21,218)	$ -
45	Boiler Plant Equipment	312	SD-72	2,327	(2,327)	-
46	Accessory Plt Equipment	315	SD-72	7,836	(7,836)	-
47	Miscellaneous Equipment	316	SD-72	6,661	(6,661)	-
48	Structures & Improvements	341	SD-72	22,615	(22,615)	-
49				$ 60,657	$ (60,657)	$ -
50						
51				$ 3,679,880	$ (3,679,880)	$ -
52						
53	Notes:					
54	[1] Holly Power Plant PIS removed in this work paper is in addition to the PIS retired in FY 2010 (accounted for on WP 2.1)					

Work Paper 2.3 - Plant in Service
Purpose: Identify Additions to Plant in Service Since the End of FY 2009

Line No.		FERC Account	FY 2009 Source Reference	Adjustments Source Reference	FY 2009 Actual	Adjustments	Test Year
A		B	C	D	E	F	G
1	**Original Cost of Plant In Service**						
2	Steam Power Generation						
3	Boiler Plant Equipment	312	SD-1	SD-5 & SD-6	$ 224,540,476	$ 199,980,166	$ 424,520,642
4	Combustion Turbine & Other Production						
5	Generator/PV	344	SD-1	SD-5	$ 299,625,412	$ 72,869,957	$ 372,495,368
6	Distribution Plant						
7	Meters	370	SD-1	SD-7	$ 75,906,947	$ 24,755,482	$ 100,662,429
8	General Plant						
9	Office Furniture & Equipment	391	SD-1	SD-5	$ 71,900,419	$ 34,822,575	$ 106,722,994
10							
11	**Accumulated Depreciation**						
12	Steam Power Generation						
13	Boiler Plant Equipment	312	SD-1	30 Year Useful Life	$ 162,718,514	$ 6,666,006	$ 169,384,520
14	Combustion Turbine & Other Production						
15	Generator/PV	344	SD-1	30 Year Useful Life	$ 77,625,173	$ 2,428,999	$ 80,054,172
16	Distribution Plant						
17	Meters	370	SD-1	25 Year Useful Life	$ 36,117,322	$ 990,219	$ 37,107,541
18	General Plant						
19	Office Furniture & Equipment	391	SD-1	12 Year Useful Life	$ 39,292,313	$ 2,901,881	$ 42,194,195
20							
21	**Net Plant In Service**						
22	Steam Power Generation						
23	Boiler Plant Equipment	312			$ 61,821,962	$ 193,314,161	$ 255,136,123
24	Combustion Turbine & Other Production						
25	Generator/PV	344			$ 222,000,238	$ 70,440,958	$ 292,441,196
26	Distribution Plant						
27	Meters	370			$ 39,789,625	$ 23,765,263	$ 63,554,888
28	General Plant						
29	Office Furniture & Equipment	391			$ 32,608,106	$ 31,920,693	$ 64,528,799
30							
31	**Depreciation Expense**						
32	Steam Power Generation						
33	Boiler Plant Equipment	312	SD-1	30 Year Useful Life	$ 6,066,242	$ 6,666,006	$ 12,732,248
34	Combustion Turbine & Other Production						
35	Generator/PV	344	SD-1	30 Year Useful Life	$ 9,720,944	$ 2,428,999	$ 12,149,942
36	Distribution Plant						
37	Meters	370	SD-1	25 Year Useful Life	$ 2,520,883	$ 990,219	$ 3,511,102
38	General Plant						
39	Office Furniture & Equipment	391	SD-1	12 Year Useful Life	$ 5,866,086	$ 2,901,881	$ 8,767,967

Austin Energy
Electric Cost of Service

Work Paper 2.4 - Plant in Service

Purpose: Identify Plant in Service Related to Meters Not in Use to be Removed from the Test Year

Line No.		FERC Account	FY 2009 Source Reference	Adjustments Source Reference	FY 2009 Actual	Adjustments	Test Year
A		B	C	D	E	F	G
1	**Original Cost of Plant In Service**						
2	Distribution Plant						
3	Meters	370	SD-1	WP 30.1	$ 75,906,947	$ (12,974,313)	$ 62,932,634
4							
5	**Accumulated Depreciation**						
6	Distribution Plant						
7	Meters	370	SD-1	Assumed Average	$ 36,117,322	$ (6,173,314)	$ 29,944,008
8							
9	**Net Plant In Service**						
10	Distribution Plant						
11	Meters	370			$ 39,789,625	$ (6,800,999)	$ 32,988,627
12							
13	**Depreciation Expense**						
14	Distribution Plant						
15	Meters	370	SD-1	Assumed Average	$ 2,520,883	$ (430,879)	$ 2,090,004

Work Paper 2.5 - Plant in Service

Purpose: Summarize the Adjustments to Electric Plant in Service for the Test Year

Line No.	Asset FERC Impacted	In Service Date	Plant Source Reference	Gross Plant In Service		Assumed Useful Life (years)	Annual Depreciation	Financing Source Reference	Debt Service Issue	FY 2011 P&I	O&M Source Reference	Associated Annual O&M Increase	O&M FERC Impacted
A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	**Additions**												
2	**Scrubbers at Fayette Power Plant**												
3	**FERC 312**	March 2011	WP 2.3	FYE 2010	$ 173,980,166			WP 5	2008A	$ 3,197,325	WP 13	$ 2,433,504	FERC 502
4	*does not include the $6.5 million budgeted for FY*		WP 2.3	FY 2011 - Projected	26,000,000			WP 5	2010A CP ref	1,378,392			
5	*2012, which is related to an ash pond*				$ 199,980,166	30	$ 6,666,006	WP 5	2010B BAB	1,832,750			
6								WP 5	Assumed CP Refunding	2,687,109			
7										$ 9,095,576			
8													
9	**New LM6000 combustion turbines at Sand Hill Energy Center**												
10	**FERC 344**	July 2010	WP 2.3		$ 72,869,957	30	$ 2,428,999		cash funded		WP 12	$ 1,448,193	FERC 548
11													
12	**CIS CRM replacement billing system (CC&B)**												
13	**FERC 391**	Oct 2011 - Jan 2012	WP 2.3		$ 34,822,575	12	$ 2,901,881		cash funded				
14													
15	**New Automated Meters**												
16	**FERC 370**	FY 2011	WP 2.3		$ 24,755,482	25	$ 990,219		cash funded				
17													
18													
19	**Retirements**												
20	**Removal of Meters Not in Use**												
21	**FERC 370**		WP 2.4		$ (12,974,313)								
22													
23	**FY 2010 Retirements**												
24	**FERC**												
25		**Steam Power Generation**											
26	**311**	Structures & Improvements	WP 2.1		$ (3,516,671)								
27	**312**	Boiler Plant Equipment	WP 2.1		(12,598,880)								
28	**314**	Turbogenerator Units	WP 2.1		(492,117)								
29	**315**	Accessory Plt Equipment	WP 2.1		(411,895)								
30	**316**	Miscellaneous Equipment	WP 2.1		(13,372)								
31					$ (17,032,935)								
32													
33		**Nuclear Power Generation**											
34	**322**	Reactor Plant Equipment	WP 2.1		$ (6,629,760)								
35	**324**	Accessory Plant Equipment	WP 2.1		(207,040)								
36	**325**	Miscellaneous Equipment	WP 2.1		(400,476)								
37					$ (7,237,276)								
38													
39		**Transmission Plant**											
40	**350**	Land & Land Rights	WP 2.1		$ (1,188)								
41	**353**	Station Equipment	WP 2.1		(157,095)								
42					$ (158,282)								
43													
44		**Distribution Plant**											
45	**362**	Station Equipment	WP 2.1		$ (54,469)								
46													
47		**General Plant**											
48	**390**	Structures & Improvements	WP 2.1		$ (6,672)								
49	**391**	Office Furniture & Equipment	WP 2.1		(9,531)								
50	**392**	Transportation Equipment	WP 2.1		(251)								
51	**393**	Stores Equipment	WP 2.1		(797)								

Work Paper 2.5 - Plant in Service

Purpose: Summarize the Adjustments to Electric Plant in Service for the Test Year

Line No.	Asset FERC Impacted	In Service Date	Plant Source Reference	Gross Plant In Service		Assumed Useful Life (years)	Annual Depreciation	Financing Source Reference	Debt Service Issue	FY 2011 P&I	O&M Source Reference	Associated Annual O&M Increase	O&M FERC Impacted
A	B	C	D	E	F	G	H	I	J	K	L	M	N
52	**396**	Power Operated Equipment	WP 2.1		(2,396)								
53	**397**	Communications Equipment	WP 2.1		(233,118)								
54				$	(252,764)								
55													
56				$	(24,735,726)								
57													
58	**Removal of Holly Power Plant [1]**												
59	**FERC**												
60	**311**		WP 2.2	$	(1,429,522)								
61	**312**		WP 2.2		(86,111)								
62	**315**		WP 2.2		(332,354)								
63	**316**		WP 2.2		(74,747)								
64	**341**		WP 2.2		(697,064)								
65				$	(2,619,796)								
66													
67	Notes:												
68	[1] Holly PIS removed is in addition to the PIS retired in FY 2010 (accounted for on WP 2.1)												

Work Paper 3 - Labor

Purpose: Develop the Labor Expenses for the Test Year

Line No.		FERC Account	FY 2009 Actual Source Reference	Holly O&M Source Reference	FY 2011 Labor Adjustments Source Reference	FY 2009 Actual	Remove Holly Labor Adjustments	Net FY 2009
A		B	C	D	E	F	G	H
1	**Power Production Expenses**							
2	Steam Power Generation							
3	**Operation**							
4	Operation Supervision and Engineering	500	SD-67	WP 24.1	WP 3.2	$ 6,677,284	$ (1,353,253)	$ 5,324,031
5	Fuel	501	SD-67	WP 24.1	WP 3.2	649,208	(387,892)	261,316
6	Steam Expenses	502	SD-67	WP 24.1	WP 3.2	2,594,646	(30,456)	2,564,190
7	Steam from other Sources	503				-	-	-
8	Steam Transferred	504				-	-	-
9	Electric Expenses	505	SD-67	WP 24.1	WP 3.2	(16,226)	-	(16,226)
10	Miscellaneous Steam Expenses	506	SD-67	WP 24.1	WP 3.2	420,836	(40,145)	380,691
11	Rents	507				-	-	-
12						$ 10,325,749	$ (1,811,747)	$ 8,514,002
13								
14	**Maintenance**							
15	Maintenance Supervision	510	SD-67	WP 24.1	WP 3.2	$ 2,106,376	$ (124,225)	$ 1,982,150
16	Maintenance of Structures	511	SD-67	WP 24.1	WP 3.2	14,957	(1,510)	13,447
17	Maintenance of Boiler Plant	512	SD-67	WP 24.1	WP 3.2	242,292	-	242,292
18	Maintenance of Electric Plant	513	SD-67	WP 24.1	WP 3.2	316,373	-	316,373
19	Maintenance of Miscellaneous Steam Plant	514	SD-67	WP 24.1	WP 3.2	1,020,343	-	1,020,343
20	Rents	515				-	-	-
21						$ 3,700,341	$ (125,736)	$ 3,574,606
22								
23	Nuclear Power Generation							
24	**Operation**							
25	Operation Supervision	517	SD-67		WP 3.2	$ 249,552	$ -	$ 249,552
26	Nuclear Fuel Expense	518				-	-	-
27	Coolants and Water	519				-	-	-
28	Steam Expenses	520				-	-	-
29	Electric Expenses	523				-	-	-
30	Misc Nuclear Power Expenses	524				-	-	-
31	Rents	525				-	-	-
32						$ 249,552	$ -	$ 249,552
33								
34	**Maintenance**							
35	Maintenance Supervision	528				$ -	$ -	$ -
36	Maintenance of Structures	529				-	-	-
37	Maintenance of Reactor Plant	530				-	-	-
38	Maintenance of Electric Plant	531				-	-	-
39	Maintenance of Miscellaneous	532				-	-	-
40						$ -	$ -	$ -
41								
42	Hydraulic Power Generation							
43	**Maintenance**							
44	Maintenance Supervision	541				$ -	$ -	$ -
45	Maintenance of Structures	542				-	-	-
46	Maintenance of Reservoirs, Dams & Waterways	543				-	-	-
47	Maintenance of Electric Plant	544				-	-	-
48	Maintenance of Miscellaneous Hydraulic Plant	545				-	-	-
49						$ -	$ -	$ -
50								
51	Other Power Generation							
52	**Operation**							
53	Operation Supervision	546	SD-67		WP 3.2	$ 1,372,451	$ -	$ 1,372,451
54	Fuel	547				-	-	-
55	Generation Expenses	548	SD-67		WP 3.2	1,914,018	-	1,914,018
56	Miscellaneous Other Power Generation Expenses	549	SD-67		WP 3.2	44,699	-	44,699
57	Rents	550	SD-67		WP 3.2	89	-	89
58						$ 3,331,257	$ -	$ 3,331,257
59								
60	**Maintenance**							
61	Maintenance Supervision and Engineering	551	SD-67		WP 3.2	$ 21,883	$ -	$ 21,883
62	Maintenance of Structures	552	SD-67		WP 3.2	34,624	-	34,624
63	Maintenance of Generating and Electric Equipment	553	SD-67		WP 3.2	826,209	-	826,209
64	Maintenance of Misc Other Power Generation Plant	554	SD-67		WP 3.2	670,515	-	670,515
65						$ 1,553,231	$ -	$ 1,553,231
66								
67	Other Power Supply							
68	Purchased Power	555				$ -	$ -	$ -
69	System Control and Load Dispatching	556	SD-67		WP 3.2	1,586,738	-	1,586,738
70	Other Power Expenses	557	SD-67		WP 3.2	430,503	-	430,503
71						$ 2,017,242	$ -	$ 2,017,242
72								
73	**Total Power Production Expense**					**$ 21,177,371**	**$ (1,937,482)**	**$ 19,239,889**
74								
75	**Transmission Expense**							
76	**Operation**							
77	Operations Supervision and Engineering	560	SD-67		WP 3.2	$ 5,359,203	$ -	$ 5,359,203
78	Load Dispatching	561	SD-67		WP 3.2	1,531,389	-	1,531,389
79	Station Expenses	562	SD-67		WP 3.2	75,826	-	75,826
80	Overhead Line Expenses	563	SD-67		WP 3.2	476,552	-	476,552

Work Paper 3 - Labor

Purpose: Develop the Labor Expenses for the Test Year

Line No.		FERC Account	FY 2009 Actual Source Reference	Holly O&M Source Reference	FY 2011 Labor Adjustments Source Reference	FY 2009 Actual	Remove Holly Labor Adjustments	Net FY 2009
A		B	C	D	E	F	G	H
81	Underground Line Expenses	564				-	-	-
82	Transmission of Electricity by Others	565	SD-67		WP 3.2	87	-	87
83	Miscellaneous Transmission Expenses	566	SD-67		WP 3.2	96,109	-	96,109
84	Rents	567				-	-	-
85						$ 7,539,165	$ -	$ 7,539,165
86								
87	**Maintenance**							
88	Maintenance Supervision and Engineering	568	SD-67		WP 3.2	$ 54	$ -	$ 54
89	Maintenance of Structures	569	SD-67		WP 3.2	1,815	-	1,815
90	Maintenance of Station Equipment	570	SD-67		WP 3.2	774,336	-	774,336
91	Maintenance of Overhead Lines	571	SD-67		WP 3.2	160,454	-	160,454
92	Maintenance of Underground Lines	572				-	-	-
93	Maintenance of Miscellaneous Transmission Plant	573	SD-67		WP 3.2	6,948	-	6,948
94						$ 943,608	$ -	$ 943,608
95								
96	**Total Transmission Expenses**					**$ 8,482,773**	**$ -**	**$ 8,482,773**
97								
98	**Distribution Expenses**							
99	**Operation**							
100	Operations Supervision and Engineering	580	SD-67		WP 3.2	$ 8,509,073	$ -	$ 8,509,073
101	Load Dispatching	581	SD-67		WP 3.2	1,240,813	-	1,240,813
102	Station Expenses	582	SD-67		WP 3.2	40,526	-	40,526
103	Overhead Line Expenses	583	SD-67		WP 3.2	5,257,702	-	5,257,702
104	Underground Line Expenses	584	SD-67		WP 3.2	2,134,116	-	2,134,116
105	Street Lighting	585	SD-67		WP 3.2	357,393	-	357,393
106	Meter Expenses	586	SD-67		WP 3.2	2,759,735	-	2,759,735
107	Customer Installation Expenses	587				-	-	-
108	Miscellaneous Distribution Expenses	588	SD-67		WP 3.2	1,512,678	-	1,512,678
109	Rents	589	SD-67		WP 3.2	(627)	-	(627)
110						$ 21,811,410	$ -	$ 21,811,410
111								
112	**Maintenance**							
113	Maintenance Supervision and Engineering	590	SD-67		WP 3.2	$ 132,140	$ -	$ 132,140
114	Maintenance of Structures	591				-	-	-
115	Maintenance of Station Equipment	592	SD-67		WP 3.2	1,188,007	-	1,188,007
116	Maintenance of Overhead Lines	593	SD-67		WP 3.2	1,012,100	-	1,012,100
117	Maintenance of Underground Lines	594	SD-67		WP 3.2	411	-	411
118	Maintenance of Line Transformers	595	SD-67		WP 3.2	7,370	-	7,370
119	Maintenance of Street Lighting and Signal Systems	596	SD-67		WP 3.2	626,859	-	626,859
120	Maintenance of Meters	597	SD-67		WP 3.2	68,127	-	68,127
121	Maintenance of Miscellaneous Distribution Plant	598	SD-67		WP 3.2	948,356	-	948,356
122						$ 3,983,370	$ -	$ 3,983,370
123								
124	**Total Distribution Expenses**					**$ 25,794,779**	**$ -**	**$ 25,794,779**
125								
126	**Customer and Information Expenses**							
127								
128	Customer Accounts Expenses							
129	Supervision	901	SD-67		WP 3.2	$ 200,796	$ -	$ 200,796
130	Meter Reading Expenses	902	SD-67		WP 3.2	3,766,648	-	3,766,648
131	Customer Records and Collection Expenses	903	SD-67		WP 3.2	14,092,904	-	14,092,904
132	Uncollectible Accounts	904				-	-	-
133	Miscellaneous Customer Accounts Expenses	905				-	-	-
134						$ 18,060,348	$ -	$ 18,060,348
135								
136	Cust. Service & Information Expense							
137	Supervision	907	SD-67		WP 3.2	$ 1,779,536	$ -	$ 1,779,536
138	Customer Assistance Expenses	908	SD-67		WP 3.2	3,768,140	-	3,768,140
139	Informational & Instructional Advertising Expenses	909	SD-67		WP 3.2	7,803	-	7,803
140	Misc Customer Service & Informational Expenses	910	SD-67		WP 3.2	534,644	-	534,644
141	Supervision	911	SD-67		WP 3.2	4,556,568	-	4,556,568
142	Demonstrating & Selling Expense	912	SD-67		WP 3.2	2,450,945	-	2,450,945
143	Advertising Expense	913	SD-67		WP 3.2	292,728	-	292,728
144	Miscellaneous Sales Expense	916	SD-67		WP 3.2	2,540	-	2,540
145						$ 13,392,904	$ -	$ 13,392,904
146								
147	**Total Customer and Information Expenses**					**$ 31,453,252**	**$ -**	**$ 31,453,252**
148								
149	**General and Administrative Expenses**							
150	Administrative and General Salaries	920	SD-67		WP 3.2	$ 36,632,398	$ -	$ 36,632,398
151	Office Supplies and Expenses	921	SD-67		WP 3.2	18,017	-	18,017
152	Administrative Expense Transferred	922				-	-	-
153	Outside Services Employed	923	SD-67		WP 3.2	4,407	-	4,407
154	Property Insurance	924				-	-	-
155	Injuries and Damages	925	SD-67		WP 3.2	12,972	-	12,972
156	Employee Pension and Benefits	926	SD-67		WP 3.2	17,510,842	-	17,510,842
157	Regulatory Commission Expense	928				-	-	-
158	General Expenses	930	SD-67		WP 3.2	869,134	-	869,134
159	Rents	931				-	-	-
160	Maintenance of General Plant	935	SD-67		WP 3.2	112	-	112
161						$ 55,047,881	$ -	$ 55,047,881
162								
163	**Total Electric Labor**					**$ 141,956,057**	**$ (1,937,482)**	**$ 140,018,575**

Work Paper 3 - Labor

Purpose: Develop the Labor Expenses for the Test Year

Line No.		FERC Account	Additional FY 2011 Labor Adjustments	Total Adjustments	Test Year
A		B	I	J	K
1	**Power Production Expenses**				
2	Steam Power Generation				
3	**Operation**				
4	Operation Supervision and Engineering	500	$ 1,417,795	$ 64,542	$ 6,741,825
5	Fuel	501	401,560	13,667	662,876
6	Steam Expenses	502	158,808	128,352	2,722,998
7	Steam from other Sources	503	-	-	-
8	Steam Transferred	504	-	-	-
9	Electric Expenses	505	36,790	36,790	20,564
10	Miscellaneous Steam Expenses	506	44,492	4,347	425,183
11	Rents	507	-	-	-
12			$ 2,059,444	$ 247,697	$ 10,573,446
13					
14	**Maintenance**				
15	Maintenance Supervision	510	$ 236,587	$ 112,362	$ 2,218,738
16	Maintenance of Structures	511	4,478	2,967	17,925
17	Maintenance of Boiler Plant	512	24,930	24,930	267,222
18	Maintenance of Electric Plant	513	20,917	20,917	337,290
19	Maintenance of Miscellaneous Steam Plant	514	64,113	64,113	1,084,456
20	Rents	515	-	-	-
21			$ 351,024	$ 225,289	$ 3,925,630
22					
23	Nuclear Power Generation				
24	**Operation**				
25	Operation Supervision	517	$ 25,989	$ 25,989	$ 275,541
26	Nuclear Fuel Expense	518	-	-	-
27	Coolants and Water	519	-	-	-
28	Steam Expenses	520	-	-	-
29	Electric Expenses	523	-	-	-
30	Misc Nuclear Power Expenses	524	-	-	-
31	Rents	525	-	-	-
32			$ 25,989	$ 25,989	$ 275,541
33					
34	**Maintenance**				
35	Maintenance Supervision	528	$ -	$ -	$ -
36	Maintenance of Structures	529	-	-	-
37	Maintenance of Reactor Plant	530	-	-	-
38	Maintenance of Electric Plant	531	-	-	-
39	Maintenance of Miscellaneous	532	-	-	-
40			$ -	$ -	$ -
41					
42	Hydraulic Power Generation				
43	**Maintenance**				
44	Maintenance Supervision	541	$ -	$ -	$ -
45	Maintenance of Structures	542	-	-	-
46	Maintenance of Reservoirs, Dams & Waterways	543	-	-	-
47	Maintenance of Electric Plant	544	-	-	-
48	Maintenance of Miscellaneous Hydraulic Plant	545	-	-	-
49			$ -	$ -	$ -
50					
51	Other Power Generation				
52	**Operation**				
53	Operation Supervision	546	$ 33,898	$ 33,898	$ 1,406,349
54	Fuel	547	-	-	-
55	Generation Expenses	548	59,468	59,468	1,973,487
56	Miscellaneous Other Power Generation Expenses	549	9,712	9,712	54,412
57	Rents	550	(74)	(74)	15
58			$ 103,006	$ 103,006	$ 3,434,262
59					
60	**Maintenance**				
61	Maintenance Supervision and Engineering	551	$ (1,394)	$ (1,394)	$ 20,489
62	Maintenance of Structures	552	7,270	7,270	41,894
63	Maintenance of Generating and Electric Equipment	553	103,015	103,015	929,224
64	Maintenance of Misc Other Power Generation Plant	554	25,445	25,445	695,960
65			$ 134,335	$ 134,335	$ 1,687,566
66					
67	Other Power Supply				
68	Purchased Power	555	$ -	$ -	$ -
69	System Control and Load Dispatching	556	70,336	70,336	1,657,074
70	Other Power Expenses	557	15,548	15,548	446,051
71			$ 85,884	$ 85,884	$ 2,103,125
72					
73	**Total Power Production Expense**		**$ 2,759,682**	**$ 822,200**	**$ 21,999,572**
74					
75	**Transmission Expense**				
76	**Operation**				
77	Operations Supervision and Engineering	560	$ (247,864)	$ (247,864)	$ 5,111,339
78	Load Dispatching	561	51,291	51,291	1,582,680
79	Station Expenses	562	7,772	7,772	83,598
80	Overhead Line Expenses	563	72,211	72,211	548,764

Work Paper 3 - Labor

Purpose: Develop the Labor Expenses for the Test Year

Line No.		FERC Account	Additional FY 2011 Labor Adjustments	Total Adjustments	Test Year
A		B	I	J	K
81	Underground Line Expenses	564	-	-	-
82	Transmission of Electricity by Others	565	18	18	105
83	Miscellaneous Transmission Expenses	566	13,304	13,304	109,413
84	Rents	567	-	-	-
85			$ (103,268)	$ (103,268)	$ 7,435,897
86					
87	**Maintenance**				
88	Maintenance Supervision and Engineering	568	$ 12	$ 12	$ 66
89	Maintenance of Structures	569	167	167	1,982
90	Maintenance of Station Equipment	570	101,010	101,010	875,347
91	Maintenance of Overhead Lines	571	18,788	18,788	179,242
92	Maintenance of Underground Lines	572	-	-	-
93	Maintenance of Miscellaneous Transmission Plant	573	(3,406)	(3,406)	3,542
94			$ 116,571	$ 116,571	$ 1,060,179
95					
96	**Total Transmission Expenses**		**$ 13,303**	**$ 13,303**	**$ 8,496,076**
97					
98	**Distribution Expenses**				
99	**Operation**				
100	Operations Supervision and Engineering	580	$ (749,001)	$ (749,001)	$ 7,760,072
101	Load Dispatching	581	(42,702)	(42,702)	1,198,111
102	Station Expenses	582	7,135	7,135	47,661
103	Overhead Line Expenses	583	425,655	425,655	5,683,357
104	Underground Line Expenses	584	275,055	275,055	2,409,171
105	Street Lighting	585	(56,721)	(56,721)	300,672
106	Meter Expenses	586	117,119	117,119	2,876,854
107	Customer Installation Expenses	587	-	-	-
108	Miscellaneous Distribution Expenses	588	44,131	44,131	1,556,809
109	Rents	589	627	627	-
110			$ 21,298	$ 21,298	$ 21,832,708
111					
112	**Maintenance**				
113	Maintenance Supervision and Engineering	590	$ 10,150	$ 10,150	$ 142,290
114	Maintenance of Structures	591	-	-	-
115	Maintenance of Station Equipment	592	172,493	172,493	1,360,500
116	Maintenance of Overhead Lines	593	(2,613)	(2,613)	1,009,486
117	Maintenance of Underground Lines	594	64	64	476
118	Maintenance of Line Transformers	595	960	960	8,330
119	Maintenance of Street Lighting and Signal Systems	596	118,456	118,456	745,315
120	Maintenance of Meters	597	11,868	11,868	79,995
121	Maintenance of Miscellaneous Distribution Plant	598	84,864	84,864	1,033,220
122			$ 396,242	$ 396,242	$ 4,379,612
123					
124	**Total Distribution Expenses**		**$ 417,540**	**$ 417,540**	**$ 26,212,320**
125					
126	**Customer and Information Expenses**				
127					
128	Customer Accounts Expenses				
129	Supervision	901	$ 29,568	$ 29,568	$ 230,365
130	Meter Reading Expenses	902	172,187	172,187	3,938,836
131	Customer Records and Collection Expenses	903	679,770	679,770	14,772,673
132	Uncollectible Accounts	904	-	-	-
133	Miscellaneous Customer Accounts Expenses	905	-	-	-
134			$ 881,526	$ 881,526	$ 18,941,874
135					
136	Cust. Service & Information Expense				
137	Supervision	907	$ 116,873	$ 116,873	$ 1,896,409
138	Customer Assistance Expenses	908	220,729	220,729	3,988,870
139	Informational & Instructional Advertising Expenses	909	(165)	(165)	7,638
140	Misc Customer Service & Informational Expenses	910	35,341	35,341	569,986
141	Supervision	911	148,205	148,205	4,704,773
142	Demonstrating & Selling Expense	912	214,577	214,577	2,665,522
143	Advertising Expense	913	37,040	37,040	329,768
144	Miscellaneous Sales Expense	916	(2,540)	(2,540)	-
145			$ 770,061	$ 770,061	$ 14,162,965
146					
147	**Total Customer and Information Expenses**		**$ 1,651,587**	**$ 1,651,587**	**$ 33,104,839**
148					
149	**General and Administrative Expenses**				
150	Administrative and General Salaries	920	$ 5,936,109	$ 5,936,109	$ 42,568,507
151	Office Supplies and Expenses	921	(3,744)	(3,744)	14,273
152	Administrative Expense Transferred	922	-	-	-
153	Outside Services Employed	923	183	183	4,590
154	Property Insurance	924	-	-	-
155	Injuries and Damages	925	(12,972)	(12,972)	-
156	Employee Pension and Benefits	926	(17,510,842)	(17,510,842)	-
157	Regulatory Commission Expense	928	-	-	-
158	General Expenses	930	134,143	134,143	1,003,277
159	Rents	931	-	-	-
160	Maintenance of General Plant	935	(112)	(112)	-
161			$ (11,457,234)	$ (11,457,234)	$ 43,590,647
162					
163	**Total Electric Labor**		**$ (6,615,122)**	**$ (8,552,604)**	**$ 133,403,453**

Work Paper 3.1 - Labor

Purpose: Functionalize Labor Cost After Adjustments to Remove Non-Electric Labor and Reassign SHEC Related O&M to Other Generation from Steam Generation

Line No.		FERC Account	FY 2011 Source Reference	FY 2011 Labor Budget Net of Capitalization	Non-Electric Source Reference	Non-Electric [1] Labor Expense	FY 2011 Electric Labor Budget
A		B	C	D	E	F	G
1	**Power Production Expenses**						
2	Steam Power Generation						
3	**Operation**						
4	Operation Supervision and Engineering	500	WP 3.2	$ 6,741,825	WP 19	$ -	$ 6,741,825
5	Fuel	501	WP 3.2	662,876		-	662,876
6	Steam Expenses	502	WP 3.2	2,722,998		-	2,722,998
7	Steam from other Sources	503		-		-	-
8	Steam Transferred	504		-		-	-
9	Electric Expenses	505	WP 3.2	20,564		-	20,564
10	Miscellaneous Steam Expenses	506	WP 3.2	425,183		-	425,183
11	Rents	507		-		-	-
12				$ 10,573,446		$ -	$ 10,573,446
13							
14	**Maintenance**						
15	Maintenance Supervision	510	WP 3.2	$ 2,218,738		$ -	$ 2,218,738
16	Maintenance of Structures	511	WP 3.2	17,925		-	17,925
17	Maintenance of Boiler Plant	512	WP 3.2	267,222		-	267,222
18	Maintenance of Electric Plant	513	WP 3.2	337,290		-	337,290
19	Maintenance of Miscellaneous Steam Plant	514	WP 3.2	1,084,456	WP 19	11,970	1,072,486
20	Rents	515		-		-	-
21				$ 3,925,630		$ 11,970	$ 3,913,660
22							
23	Nuclear Power Generation						
24	**Operation**						
25	Operation Supervision	517	WP 3.2	$ 275,541		$ -	$ 275,541
26	Nuclear Fuel Expense	518		-		-	-
27	Coolants and Water	519		-		-	-
28	Steam Expenses	520		-		-	-
29	Electric Expenses	523		-		-	-
30	Misc Nuclear Power Expenses	524		-		-	-
31	Rents	525		-		-	-
32				$ 275,541		$ -	$ 275,541
33							
34	**Maintenance**						
35	Maintenance Supervision	528		$ -		$ -	$ -
36	Maintenance of Structures	529		-		-	-
37	Maintenance of Reactor Plant	530		-		-	-
38	Maintenance of Electric Plant	531		-		-	-
39	Maintenance of Miscellaneous	532		-		-	-
40				$ -		$ -	$ -
41							
42	Hydraulic Power Generation						
43	**Maintenance**						
44	Maintenance Supervision	541		$ -		$ -	$ -
45	Maintenance of Structures	542		-		-	-
46	Maintenance of Reservoirs, Dams & Waterways	543		-		-	-
47	Maintenance of Electric Plant	544		-		-	-
48	Maintenance of Miscellaneous Hydraulic Plant	545		-		-	-
49				$ -		$ -	$ -
50							
51	Other Power Generation						
52	**Operation**						
53	Operation Supervision	546	WP 3.2	$ 1,406,349	WP 19	$ 613,208	$ 793,142
54	Fuel	547		-		-	-
55	Generation Expenses	548	WP 3.2	1,973,487	WP 19	330	1,973,157
56	Miscellaneous Other Power Generation Expenses	549	WP 3.2	54,412	WP 19	32,164	22,248
57	Rents	550	WP 3.2	15	WP 19	-	15
58				$ 3,434,262		$ 645,702	$ 2,788,561
59							
60	**Maintenance**						
61	Maintenance Supervision and Engineering	551	WP 3.2	$ 20,489		$ -	$ 20,489
62	Maintenance of Structures	552	WP 3.2	41,894	WP 19	210	41,684
63	Maintenance of Generating and Electric Equipment	553	WP 3.2	929,224		-	929,224
64	Maintenance of Misc Other Power Generation Plant	554	WP 3.2	695,960	WP 19	455	695,505
65				$ 1,687,566		$ 665	$ 1,686,901
66							
67	Other Power Supply						
68	Purchased Power	555		$ -		$ -	$ -
69	System Control and Load Dispatching	556	WP 3.2	1,657,074		-	1,657,074
70	Other Power Expenses	557	WP 3.2	446,051		-	446,051
71				$ 2,103,125		$ -	$ 2,103,125
72							
73	**Total Power Production Expense**			**$ 21,999,572**		**$ 658,337**	**$ 21,341,235**
74							
75	**Transmission Expense**						
76	**Operation**						
77	Operations Supervision and Engineering	560	WP 3.2	$ 5,111,339		$ -	$ 5,111,339
78	Load Dispatching	561	WP 3.2	1,582,680		-	1,582,680
79	Station Expenses	562	WP 3.2	83,598		-	83,598
80	Overhead Line Expenses	563	WP 3.2	548,764		-	548,764
81	Underground Line Expenses	564		-		-	-
82	Transmission of Electricity by Others	565	WP 3.2	105		-	105
83	Miscellaneous Transmission Expenses	566	WP 3.2	109,413		-	109,413
84	Rents	567		-		-	-
85				$ 7,435,897		$ -	$ 7,435,897

Work Paper 3.1 - Labor
Purpose: Functionalize Labor Cost After Adjustments to Remove Non-Electric Labor and Reassign SHEC Related O&M to Other Generation from Steam Generation

Line No.		FERC Account	FY 2011 Source Reference	FY 2011 Labor Budget Net of Capitalization	Non-Electric Source Reference	Non-Electric [1] Labor Expense	FY 2011 Electric Labor Budget
A		B	C	D	E	F	G
86							
87	**Maintenance**						
88	Maintenance Supervision and Engineering	568	WP 3.2	$ 66		$ -	$ 66
89	Maintenance of Structures	569	WP 3.2	1,982		-	1,982
90	Maintenance of Station Equipment	570	WP 3.2	875,347		-	875,347
91	Maintenance of Overhead Lines	571	WP 3.2	179,242		-	179,242
92	Maintenance of Underground Lines	572		-		-	-
93	Maintenance of Miscellaneous Transmission Plant	573	WP 3.2	3,542		-	3,542
94				$ 1,060,179		$ -	$ 1,060,179
95							
96	**Total Transmission Expenses**			**$ 8,496,076**		**$ -**	**$ 8,496,076**
97							
98	**Distribution Expenses**						
99	**Operation**						
100	Operations Supervision and Engineering	580	WP 3.2	$ 7,760,072		$ -	$ 7,760,072
101	Load Dispatching	581	WP 3.2	1,198,111		-	1,198,111
102	Station Expenses	582	WP 3.2	47,661		-	47,661
103	Overhead Line Expenses	583	WP 3.2	5,683,357		-	5,683,357
104	Underground Line Expenses	584	WP 3.2	2,409,171	WP 19	573	2,408,599
105	Street Lighting	585	WP 3.2	300,672		-	300,672
106	Meter Expenses	586	WP 3.2	2,876,854		-	2,876,854
107	Customer Installation Expenses	587		-		-	-
108	Miscellaneous Distribution Expenses	588	WP 3.2	1,556,809		-	1,556,809
109	Rents	589		-		-	-
110				$ 21,832,708		$ 573	$ 21,832,135
111							
112	**Maintenance**						
113	Maintenance Supervision and Engineering	590	WP 3.2	$ 142,290		$ -	$ 142,290
114	Maintenance of Structures	591		-		-	-
115	Maintenance of Station Equipment	592	WP 3.2	1,360,500		-	1,360,500
116	Maintenance of Overhead Lines	593	WP 3.2	1,009,486		-	1,009,486
117	Maintenance of Underground Lines	594	WP 3.2	476		-	476
118	Maintenance of Line Transformers	595	WP 3.2	8,330		-	8,330
119	Maintenance of Street Lighting and Signal Systems	596	WP 3.2	745,315		-	745,315
120	Maintenance of Meters	597	WP 3.2	79,995		-	79,995
121	Maintenance of Miscellaneous Distribution Plant	598	WP 3.2	1,033,220		-	1,033,220
122				$ 4,379,612		$ -	$ 4,379,612
123							
124	**Total Distribution Expenses**			**$ 26,212,320**		**$ 573**	**$ 26,211,747**
125							
126	**Customer and Information Expenses**						
127							
128	Customer Accounts Expenses						
129	Supervision	901	WP 3.2	$ 230,365		$ -	$ 230,365
130	Meter Reading Expenses	902	WP 3.2	3,938,836		-	3,938,836
131	Customer Records and Collection Expenses	903	WP 3.2	14,772,673		-	14,772,673
132	Uncollectible Accounts	904		-		-	-
133	Miscellaneous Customer Accounts Expenses	905		-		-	-
134				$ 18,941,874		$ -	$ 18,941,874
135							
136	Cust. Service & Information Expense						
137	Supervision	907	WP 3.2	$ 1,896,409	WP 19	$ 320	$ 1,896,089
138	Customer Assistance Expenses	908	WP 3.2	3,988,870		-	3,988,870
139	Informational & Instructional Advertising Expenses	909	WP 3.2	7,638		-	7,638
140	Misc Customer Service & Informational Expenses	910	WP 3.2	569,986		-	569,986
141	Supervision	911	WP 3.2	4,704,773		-	4,704,773
142	Demonstrating & Selling Expense	912	WP 3.2	2,665,522		-	2,665,522
143	Advertising Expense	913	WP 3.2	329,768		-	329,768
144	Miscellaneous Sales Expense	916		-		-	-
145				$ 14,162,965		$ 320	$ 14,162,645
146							
147	**Total Customer and Information Expenses**			**$ 33,104,839**		**$ 320**	**$ 33,104,519**
148							
149	**General and Administrative Expenses**						
150	Administrative and General Salaries	920	WP 3.2	$ 42,568,507	WP 19	$ -	$ 42,568,507
151	Office Supplies and Expenses	921	WP 3.2	14,273	WP 19	2,410	11,863
152	Administrative Expense Transferred	922		-		-	-
153	Outside Services Employed	923	WP 3.2	4,590		-	4,590
154	Property Insurance	924		-		-	-
155	Injuries and Damages	925		-		-	-
156	Employee Pension and Benefits	926		-		-	-
157	Regulatory Commission Expense	928		-		-	-
158	General Expenses	930	WP 3.2	1,003,277	WP 19	324	1,002,953
159	Rents	931		-		-	-
160	Maintenance of General Plant	935		-		-	-
161				$ 43,590,647		$ 2,734	$ 43,587,914
162							
163	**Total Electric Labor**			**$ 133,403,453**		**$ 661,963**	**$ 132,741,490**
164							
165	**Non-Electric Utility Labor**						
166	Expenses - Non-utility operations	417	WP 3.2	$ 7,756,383		$ 7,756,383	$ -
167				$ 7,756,383		$ 7,756,383	$ -
168							
169	**Total Labor**			**$ 141,159,836**		**$ 8,418,346**	**$ 132,741,490**
170							
171	Notes:						
172	[1] Assumes that 100% of the non-electric cost identified in WP 19 is labor						
173	[2] Fayette Power Plant is operated under contract (i.e., not AE staff)						

Work Paper 3.1 - Labor

Purpose: Functionalize Labor Cost After Adjustments to Remove Non-Electric Labor

Line No.		FERC Account	SHEC Source Reference	SHEC Non-Fuel O&M	Total Non-Fuel O&M Less FPP & Holly [2] O&M	Portion of Steam FERC that is SHEC	Adjustment to Re-FERC SHEC	Adjusted Electric Labor Budget
A		B	H	I	J	K	L	M
1	**Power Production Expenses**							
2	Steam Power Generation							
3	**Operation**							
4	Operation Supervision and Engineering	500	SD-8	$ 719,337	$ 6,085,561	11.82%	$ (796,909)	$ 5,944,916
5	Fuel	501					-	662,876
6	Steam Expenses	502	SD-8	30,386	2,890,865	1.05%	(28,622)	2,694,376
7	Steam from other Sources	503					-	-
8	Steam Transferred	504					-	-
9	Electric Expenses	505	SD-8	30,163	54,670	55.17%	(11,346)	9,218
10	Miscellaneous Steam Expenses	506	SD-8	225,344	1,709,622	13.18%	(56,043)	369,140
11	Rents	507					-	-
12							$ (892,920)	$ 9,680,526
13								
14	**Maintenance**							
15	Maintenance Supervision	510	SD-8	$ 21,823	$ 2,139,869	1.02%	$ (22,627)	$ 2,196,111
16	Maintenance of Structures	511	SD-8	34,898	69,654	50.10%	(8,981)	8,944
17	Maintenance of Boiler Plant	512	SD-8	555,089	1,737,337	31.95%	(85,379)	181,843
18	Maintenance of Electric Plant	513	SD-8	1,631,583	2,019,642	80.79%	(272,482)	64,808
19	Maintenance of Miscellaneous Steam Plant	514	SD-8	203,718	2,184,318	9.33%	(100,024)	972,462
20	Rents	515					-	-
21							$ (489,493)	$ 3,424,167
22								
23	Nuclear Power Generation							
24	**Operation**							
25	Operation Supervision	517					$ -	$ 275,541
26	Nuclear Fuel Expense	518					-	-
27	Coolants and Water	519					-	-
28	Steam Expenses	520					-	-
29	Electric Expenses	523					-	-
30	Misc Nuclear Power Expenses	524					-	-
31	Rents	525					-	-
32							$ -	$ 275,541
33								
34	**Maintenance**							
35	Maintenance Supervision	528					$ -	$ -
36	Maintenance of Structures	529					-	-
37	Maintenance of Reactor Plant	530					-	-
38	Maintenance of Electric Plant	531					-	-
39	Maintenance of Miscellaneous	532					-	-
40							$ -	$ -
41								
42	Hydraulic Power Generation							
43	**Maintenance**							
44	Maintenance Supervision	541					$ -	$ -
45	Maintenance of Structures	542					-	-
46	Maintenance of Reservoirs, Dams & Waterways	543					-	-
47	Maintenance of Electric Plant	544					-	-
48	Maintenance of Miscellaneous Hydraulic Plant	545					-	-
49							$ -	$ -
50								
51	Other Power Generation							
52	**Operation**							
53	Operation Supervision	546					$ 796,909	$ 1,590,051
54	Fuel	547					-	-
55	Generation Expenses	548					28,622	2,001,778
56	Miscellaneous Other Power Generation Expenses	549					67,389	89,637
57	Rents	550					-	15
58							$ 892,920	$ 3,681,481
59								
60	**Maintenance**							
61	Maintenance Supervision and Engineering	551					$ 22,627	$ 43,116
62	Maintenance of Structures	552					8,981	50,665
63	Maintenance of Generating and Electric Equipment	553					357,861	1,287,085
64	Maintenance of Misc Other Power Generation Plant	554					100,024	795,529
65							$ 489,493	$ 2,176,394
66								
67	Other Power Supply							
68	Purchased Power	555					$ -	$ -
69	System Control and Load Dispatching	556					-	1,657,074
70	Other Power Expenses	557					-	446,051
71							$ -	$ 2,103,125
72								
73	**Total Power Production Expense**						**$ -**	**$ 21,341,235**
74								
75	**Transmission Expense**							
76	**Operation**							
77	Operations Supervision and Engineering	560					$ -	$ 5,111,339
78	Load Dispatching	561					-	1,582,680
79	Station Expenses	562					-	83,598
80	Overhead Line Expenses	563					-	548,764
81	Underground Line Expenses	564					-	-
82	Transmission of Electricity by Others	565					-	105
83	Miscellaneous Transmission Expenses	566					-	109,413
84	Rents	567					-	-
85							$ -	$ 7,435,897
86								
87	**Maintenance**							
88	Maintenance Supervision and Engineering	568					$ -	$ 66
89	Maintenance of Structures	569					-	1,982

Work Paper 3.1 - Labor

Purpose: Functionalize Labor Cost After Adjustments to Remove Non-Electric Labor

Line No.		FERC Account	SHEC Source Reference	SHEC Non-Fuel O&M	Total Non-Fuel O&M Less FPP & Holly [2] O&M	Portion of Steam FERC that is SHEC	Adjustment to Re-FERC SHEC	Adjusted Electric Labor Budget
A		B	H	I	J	K	L	M
90	Maintenance of Station Equipment	570					-	875,347
91	Maintenance of Overhead Lines	571					-	179,242
92	Maintenance of Underground Lines	572					-	-
93	Maintenance of Miscellaneous Transmission Plant	573					-	3,542
94							$ -	$ 1,060,179
95								
96	**Total Transmission Expenses**						**$ -**	**$ 8,496,076**
97								
98	**Distribution Expenses**							
99	**Operation**							
100	Operations Supervision and Engineering	580					$ -	$ 7,760,072
101	Load Dispatching	581					-	1,198,111
102	Station Expenses	582					-	47,661
103	Overhead Line Expenses	583					-	5,683,357
104	Underground Line Expenses	584					-	2,408,599
105	Street Lighting	585					-	300,672
106	Meter Expenses	586					-	2,876,854
107	Customer Installation Expenses	587					-	-
108	Miscellaneous Distribution Expenses	588					-	1,556,809
109	Rents	589					-	-
110							$ -	$ 21,832,135
111								
112	**Maintenance**							
113	Maintenance Supervision and Engineering	590					$ -	$ 142,290
114	Maintenance of Structures	591					-	-
115	Maintenance of Station Equipment	592					-	1,360,500
116	Maintenance of Overhead Lines	593					-	1,009,486
117	Maintenance of Underground Lines	594					-	476
118	Maintenance of Line Transformers	595					-	8,330
119	Maintenance of Street Lighting and Signal Systems	596					-	745,315
120	Maintenance of Meters	597					-	79,995
121	Maintenance of Miscellaneous Distribution Plant	598					-	1,033,220
122							$ -	$ 4,379,612
123								
124	**Total Distribution Expenses**						**$ -**	**$ 26,211,747**
125								
126	**Customer and Information Expenses**							
127								
128	Customer Accounts Expenses							
129	Supervision	901					$ -	$ 230,365
130	Meter Reading Expenses	902					-	3,938,836
131	Customer Records and Collection Expenses	903					-	14,772,673
132	Uncollectible Accounts	904					-	-
133	Miscellaneous Customer Accounts Expenses	905					-	-
134							$ -	$ 18,941,874
135								
136	Cust. Service & Information Expense							
137	Supervision	907					$ -	$ 1,896,089
138	Customer Assistance Expenses	908					-	3,988,870
139	Informational & Instructional Advertising Expenses	909					-	7,638
140	Misc Customer Service & Informational Expenses	910					-	569,986
141	Supervision	911					-	4,704,773
142	Demonstrating & Selling Expense	912					-	2,665,522
143	Advertising Expense	913					-	329,768
144	Miscellaneous Sales Expense	916					-	-
145							$ -	$ 14,162,645
146								
147	**Total Customer and Information Expenses**						**$ -**	**$ 33,104,519**
148								
149	**General and Administrative Expenses**							
150	Administrative and General Salaries	920					$ -	$ 42,568,507
151	Office Supplies and Expenses	921					-	11,863
152	Administrative Expense Transferred	922					-	-
153	Outside Services Employed	923					-	4,590
154	Property Insurance	924					-	-
155	Injuries and Damages	925					-	-
156	Employee Pension and Benefits	926					-	-
157	Regulatory Commission Expense	928					-	-
158	General Expenses	930					-	1,002,953
159	Rents	931					-	-
160	Maintenance of General Plant	935					-	-
161							$ -	$ 43,587,914
162								
163	**Total Electric Labor**						**$ -**	**$ 132,741,490**
164								
165	**Non-Electric Utility Labor**							
166	Expenses - Non-utility operations	417					$ -	$ -
167							$ -	$ -
168								
169	**Total Labor**						**$ -**	**$ 132,741,490**

Work Paper 3.1 - Labor
Purpose: Functionalize Labor Cost After Adjustments to Remove Non-Electric Labor

Line No.		FERC Account	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A		B	N	O	P	Q	R	S
1	**Power Production Expenses**							
2	Steam Power Generation							
3	**Operation**							
4	Operation Supervision and Engineering	500	Production	$ 5,944,916	$ -	$ -	$ -	$ 5,944,916
5	Fuel	501	Production	662,876	-	-	-	662,876
6	Steam Expenses	502	Production	2,694,376	-	-	-	2,694,376
7	Steam from other Sources	503	Production	-	-	-	-	-
8	Steam Transferred	504	Production	-	-	-	-	-
9	Electric Expenses	505	Production	9,218	-	-	-	9,218
10	Miscellaneous Steam Expenses	506	Production	369,140	-	-	-	369,140
11	Rents	507	Production	-	-	-	-	-
12				$ 9,680,526	$ -	$ -	$ -	$ 9,680,526
13								
14	**Maintenance**							
15	Maintenance Supervision	510	Production	$ 2,196,111	$ -	$ -	$ -	$ 2,196,111
16	Maintenance of Structures	511	Production	8,944	-	-	-	8,944
17	Maintenance of Boiler Plant	512	Production	181,843	-	-	-	181,843
18	Maintenance of Electric Plant	513	Production	64,808	-	-	-	64,808
19	Maintenance of Miscellaneous Steam Plant	514	Production	972,462	-	-	-	972,462
20	Rents	515	Production	-	-	-	-	-
21				$ 3,424,167	$ -	$ -	$ -	$ 3,424,167
22								
23	Nuclear Power Generation							
24	**Operation**							
25	Operation Supervision	517	Production	$ 275,541	$ -	$ -	$ -	$ 275,541
26	Nuclear Fuel Expense	518	Production	-	-	-	-	-
27	Coolants and Water	519	Production	-	-	-	-	-
28	Steam Expenses	520	Production	-	-	-	-	-
29	Electric Expenses	523	Production	-	-	-	-	-
30	Misc Nuclear Power Expenses	524	Production	-	-	-	-	-
31	Rents	525	Production	-	-	-	-	-
32				$ 275,541	$ -	$ -	$ -	$ 275,541
33								
34	**Maintenance**							
35	Maintenance Supervision	528	Production	$ -	$ -	$ -	$ -	$ -
36	Maintenance of Structures	529	Production	-	-	-	-	-
37	Maintenance of Reactor Plant	530	Production	-	-	-	-	-
38	Maintenance of Electric Plant	531	Production	-	-	-	-	-
39	Maintenance of Miscellaneous	532	Production	-	-	-	-	-
40				$ -	$ -	$ -	$ -	$ -
41								
42	Hydraulic Power Generation							
43	**Maintenance**							
44	Maintenance Supervision	541	Production	$ -	$ -	$ -	$ -	$ -
45	Maintenance of Structures	542	Production	-	-	-	-	-
46	Maintenance of Reservoirs, Dams & Waterways	543	Production	-	-	-	-	-
47	Maintenance of Electric Plant	544	Production	-	-	-	-	-
48	Maintenance of Miscellaneous Hydraulic Plant	545	Production	-	-	-	-	-
49				$ -	$ -	$ -	$ -	$ -
50								
51	Other Power Generation							
52	**Operation**							
53	Operation Supervision	546	Production	$ 1,590,051	$ -	$ -	$ -	$ 1,590,051
54	Fuel	547	Production	-	-	-	-	-
55	Generation Expenses	548	Production	2,001,778	-	-	-	2,001,778
56	Miscellaneous Other Power Generation Expenses	549	Production	89,637	-	-	-	89,637
57	Rents	550	Production	15	-	-	-	15
58				$ 3,681,481	$ -	$ -	$ -	$ 3,681,481
59								
60	**Maintenance**							
61	Maintenance Supervision and Engineering	551	Production	$ 43,116	$ -	$ -	$ -	$ 43,116
62	Maintenance of Structures	552	Production	50,665	-	-	-	50,665
63	Maintenance of Generating and Electric Equipment	553	Production	1,287,085	-	-	-	1,287,085
64	Maintenance of Misc Other Power Generation Plant	554	Production	795,529	-	-	-	795,529
65				$ 2,176,394	$ -	$ -	$ -	$ 2,176,394
66								
67	Other Power Supply							
68	Purchased Power	555	Production	$ -	$ -	$ -	$ -	$ -
69	System Control and Load Dispatching	556	Production	1,657,074	-	-	-	1,657,074
70	Other Power Expenses	557	Production	446,051	-	-	-	446,051
71				$ 2,103,125	$ -	$ -	$ -	$ 2,103,125
72								
73	**Total Power Production Expense**			**$ 21,341,235**	**$ -**	**$ -**	**$ -**	**$ 21,341,235**
74								
75	**Transmission Expense**							
76	**Operation**							
77	Operations Supervision and Engineering	560	Transmission	$ -	$ 5,111,339	$ -	$ -	$ 5,111,339
78	Load Dispatching	561	Transmission	-	1,582,680	-	-	1,582,680
79	Station Expenses	562	Transmission	-	83,598	-	-	83,598
80	Overhead Line Expenses	563	Transmission	-	548,764	-	-	548,764
81	Underground Line Expenses	564	Transmission	-	-	-	-	-
82	Transmission of Electricity by Others	565	Transmission	-	105	-	-	105
83	Miscellaneous Transmission Expenses	566	Transmission	-	109,413	-	-	109,413
84	Rents	567	Transmission	-	-	-	-	-
85				$ -	$ 7,435,897	$ -	$ -	$ 7,435,897
86								
87	**Maintenance**							
88	Maintenance Supervision and Engineering	568	Transmission	$ -	$ 66	$ -	$ -	$ 66
89	Maintenance of Structures	569	Transmission	-	1,982	-	-	1,982

Work Paper 3.1 - Labor
Purpose: Functionalize Labor Cost After Adjustments to Remove Non-Electric Labor

Line No.		FERC Account	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A		B	N	O	P	Q	R	S
90	Maintenance of Station Equipment	570	Transmission	-	875,347	-	-	875,347
91	Maintenance of Overhead Lines	571	Transmission	-	179,242	-	-	179,242
92	Maintenance of Underground Lines	572	Transmission	-	-	-	-	-
93	Maintenance of Miscellaneous Transmission Plant	573	Transmission	-	3,542	-	-	3,542
94				$ -	$ 1,060,179	$ -	$ -	$ 1,060,179
95								
96	**Total Transmission Expenses**			**$ -**	**$ 8,496,076**	**$ -**	**$ -**	**$ 8,496,076**
97								
98	**Distribution Expenses**							
99	**Operation**							
100	Operations Supervision and Engineering	580	Distribution	$ -	$ -	$ 7,760,072	$ -	$ 7,760,072
101	Load Dispatching	581	Distribution	-	-	1,198,111	-	1,198,111
102	Station Expenses	582	Distribution	-	-	47,661	-	47,661
103	Overhead Line Expenses	583	Distribution	-	-	5,683,357	-	5,683,357
104	Underground Line Expenses	584	Distribution	-	-	2,408,599	-	2,408,599
105	Street Lighting	585	Distribution	-	-	300,672	-	300,672
106	Meter Expenses	586	Distribution	-	-	2,876,854	-	2,876,854
107	Customer Installation Expenses	587	Distribution	-	-	-	-	-
108	Miscellaneous Distribution Expenses	588	Distribution	-	-	1,556,809	-	1,556,809
109	Rents	589	Distribution	-	-	-	-	-
110				$ -	$ -	$ 21,832,135	$ -	$ 21,832,135
111								
112	**Maintenance**							
113	Maintenance Supervision and Engineering	590	Distribution	$ -	$ -	$ 142,290	$ -	$ 142,290
114	Maintenance of Structures	591	Distribution	-	-	-	-	-
115	Maintenance of Station Equipment	592	Distribution	-	-	1,360,500	-	1,360,500
116	Maintenance of Overhead Lines	593	Distribution	-	-	1,009,486	-	1,009,486
117	Maintenance of Underground Lines	594	Distribution	-	-	476	-	476
118	Maintenance of Line Transformers	595	Distribution	-	-	8,330	-	8,330
119	Maintenance of Street Lighting and Signal Systems	596	Distribution	-	-	745,315	-	745,315
120	Maintenance of Meters	597	Distribution	-	-	79,995	-	79,995
121	Maintenance of Miscellaneous Distribution Plant	598	Distribution	-	-	1,033,220	-	1,033,220
122				$ -	$ -	$ 4,379,612	$ -	$ 4,379,612
123								
124	**Total Distribution Expenses**			**$ -**	**$ -**	**$ 26,211,747**	**$ -**	**$ 26,211,747**
125								
126	**Customer and Information Expenses**							
127								
128	Customer Accounts Expenses							
129	Supervision	901	Customer	$ -	$ -	$ -	$ 230,365	$ 230,365
130	Meter Reading Expenses	902	Customer	-	-	-	3,938,836	3,938,836
131	Customer Records and Collection Expenses	903	Customer	-	-	-	14,772,673	14,772,673
132	Uncollectible Accounts	904	Customer	-	-	-	-	-
133	Miscellaneous Customer Accounts Expenses	905	Customer	-	-	-	-	-
134				$ -	$ -	$ -	$ 18,941,874	$ 18,941,874
135								
136	Cust. Service & Information Expense							
137	Supervision	907	Customer	$ -	$ -	$ -	$ 1,896,089	$ 1,896,089
138	Customer Assistance Expenses	908	Customer	-	-	-	3,988,870	3,988,870
139	Informational & Instructional Advertising Expenses	909	Customer	-	-	-	7,638	7,638
140	Misc Customer Service & Informational Expenses	910	Customer	-	-	-	569,986	569,986
141	Supervision	911	Customer	-	-	-	4,704,773	4,704,773
142	Demonstrating & Selling Expense	912	Customer	-	-	-	2,665,522	2,665,522
143	Advertising Expense	913	Customer	-	-	-	329,768	329,768
144	Miscellaneous Sales Expense	916	Customer	-	-	-	-	-
145				$ -	$ -	$ -	$ 14,162,645	$ 14,162,645
146								
147	**Total Customer and Information Expenses**			**$ -**	**$ -**	**$ -**	**$ 33,104,519**	**$ 33,104,519**
148								
149	**General and Administrative Expenses**							
150	Administrative and General Salaries	920	PAYXAG	$ 10,189,883	$ 4,056,654	$ 12,515,425	$ 15,806,544	$ 42,568,507
151	Office Supplies and Expenses	921	PAYXAG	2,840	1,131	3,488	4,405	11,863
152	Administrative Expense Transferred	922	PAYXAG	-	-	-	-	-
153	Outside Services Employed	923	TOMXFP	2,300	1,033	651	606	4,590
154	Property Insurance	924	PAYXAG	-	-	-	-	-
155	Injuries and Damages	925	PAYXAG	-	-	-	-	-
156	Employee Pension and Benefits	926	PAYXAG	-	-	-	-	-
157	Regulatory Commission Expense	928	PAYXAG	-	-	-	-	-
158	General Expenses	930	PAYXAG	240,083	95,579	294,875	372,417	1,002,953
159	Rents	931	PAYXAG	-	-	-	-	-
160	Maintenance of General Plant	935	GNLPLT-N	-	-	-	-	-
161				$ 10,435,106	$ 4,154,396	$ 12,814,439	$ 16,183,972	$ 43,587,914
162								
163	**Total Electric Labor**			**$ 31,776,341**	**$ 12,650,472**	**$ 39,026,186**	**$ 49,288,491**	**$ 132,741,490**
164								
165	**Non-Electric Utility Labor**							
166	Expenses - Non-utility operations	417		$ -	$ -	$ -	$ -	$ -
167				$ -	$ -	$ -	$ -	$ -
168								
169	**Total Labor**			**$ 31,776,341**	**$ 12,650,472**	**$ 39,026,186**	**$ 49,288,491**	**$ 132,741,490**

Work Paper 3.2 - Labor

Purpose: Develop Known and Measurable Adjustments to Remove GAAP Adjustments to Labor Costs in FY 2009 and Reflect Increases in Employee Benefit Costs (e.g., Health, Retirement) and a General Wage Increase Effective at the Beginning of FY 2011

Line No.		FERC Account	with GAAP Source Reference	w/o GAAP Source Reference	FY 2009 Actual with GAAP	Remove GAAP Adjustments	FY 2009 Actual w/o GAAP	Capitalized Source Reference
A		B	C	D	E	F	G	H
1	**Power Production Expenses**							
2	Steam Power Generation							
3	**Operation**							
4	Operation Supervision and Engineering	500	SD-67	SD-68	$ 6,870,918	$ (176,065)	$ 6,694,853	SD-67
5	Fuel	501	SD-67	SD-68	649,208	(27,087)	622,121	
6	Steam Expenses	502	SD-67	SD-68	2,594,646	(3,850)	2,590,796	
7	Steam from other Sources	503			-		-	
8	Steam Transferred	504			-		-	
9	Electric Expenses	505	SD-67	SD-68	(16,226)	34,961	18,735	
10	Miscellaneous Steam Expenses	506	SD-67	SD-68	425,146	170	425,316	SD-67
11	Rents	507			-		-	
12					$ 10,523,693		$ 10,351,822	
13								
14	**Maintenance**							
15	Maintenance Supervision	510	SD-67	SD-68	$ 2,112,875		$ 2,112,875	SD-67
16	Maintenance of Structures	511	SD-67	SD-68	14,957		14,957	
17	Maintenance of Boiler Plant	512	SD-67	SD-68	242,292		242,292	
18	Maintenance of Electric Plant	513	SD-67	SD-68	349,181		349,181	SD-67
19	Maintenance of Miscellaneous Steam Plant	514	SD-67	SD-68	1,022,339		1,022,339	SD-67
20	Rents	515			-		-	
21					$ 3,741,645		$ 3,741,645	
22								
23	Nuclear Power Generation							
24	**Operation**							
25	Operation Supervision	517	SD-67	SD-68	$ 249,552		$ 249,552	
26	Nuclear Fuel Expense	518			-		-	
27	Coolants and Water	519			-		-	
28	Steam Expenses	520			-		-	
29	Electric Expenses	523			-		-	
30	Misc Nuclear Power Expenses	524			-		-	
31	Rents	525			-		-	
32					$ 249,552		$ 249,552	
33								
34	**Maintenance**							
35	Maintenance Supervision	528			$ -		$ -	
36	Maintenance of Structures	529			-		-	
37	Maintenance of Reactor Plant	530			-		-	
38	Maintenance of Electric Plant	531			-		-	
39	Maintenance of Miscellaneous	532			-		-	
40					$ -		$ -	
41								
42	Hydraulic Power Generation							
43	**Maintenance**							
44	Maintenance Supervision	541			$ -		$ -	
45	Maintenance of Structures	542			-		-	
46	Maintenance of Reservoirs, Dams & Waterways	543			-		-	
47	Maintenance of Electric Plant	544			-		-	
48	Maintenance of Miscellaneous Hydraulic Plant	545			-		-	
49					$ -		$ -	
50								
51	Other Power Generation							
52	**Operation**							
53	Operation Supervision	546	SD-67	SD-68	$ 1,376,779	$ 10,156	$ 1,386,935	SD-67
54	Fuel	547			-		-	
55	Generation Expenses	548	SD-67	SD-68	1,914,018		1,914,018	
56	Miscellaneous Other Power Generation Expenses	549	SD-67	SD-68	44,699		44,699	
57	Rents	550	SD-67	SD-68	89		89	
58					$ 3,335,585		$ 3,345,741	
59								
60	**Maintenance**							
61	Maintenance Supervision and Engineering	551	SD-67	SD-68	$ 22,072		$ 22,072	SD-67
62	Maintenance of Structures	552	SD-67	SD-68	34,624		34,624	
63	Maintenance of Generating and Electric Equipment	553	SD-67	SD-68	892,081		892,081	SD-67
64	Maintenance of Misc Other Power Generation Plant	554	SD-67	SD-68	722,301		722,301	SD-67
65					$ 1,671,077		$ 1,671,077	
66								
67	Other Power Supply							
68	Purchased Power	555			$ -		$ -	
69	System Control and Load Dispatching	556	SD-67	SD-68	1,586,738	(9,136)	1,577,602	
70	Other Power Expenses	557	SD-67	SD-68	430,503		430,503	
71					$ 2,017,242		$ 2,008,106	
72								
73	**Total Power Production Expense**				**$ 21,538,794**		**$ 21,367,943**	
74								
75	**Transmission Expense**							
76	**Operation**							
77	Operations Supervision and Engineering	560	SD-67	SD-68	$ 6,764,357	$ (156,991)	$ 6,607,366	SD-67
78	Load Dispatching	561	SD-67	SD-68	1,531,505	(5,914)	1,525,591	SD-67
79	Station Expenses	562	SD-67	SD-68	290,173	(2,568)	287,605	SD-67
80	Overhead Line Expenses	563	SD-67	SD-68	1,374,087		1,374,087	SD-67

Work Paper 3.2 - Labor

Purpose: Develop Known and Measurable Adjustments to Remove GAAP Adjustments to Labor Costs in FY 2009 and Reflect Increases in Employee Benefit Costs (e.g., Health, Retirement) and a General Wage Increase Effective at the Beginning of FY 2011

Line No.		FERC Account	with GAAP Source Reference	w/o GAAP Source Reference	FY 2009 Actual with GAAP	Remove GAAP Adjustments	FY 2009 Actual w/o GAAP	Capitalized Source Reference
A		B	C	D	E	F	G	H
81	Underground Line Expenses	564	SD-67	SD-68	210		210	SD-67
82	Transmission of Electricity by Others	565	SD-67	SD-68	87		87	
83	Miscellaneous Transmission Expenses	566	SD-67	SD-68	99,757		99,757	SD-67
84	Rents	567			-		-	
85					$ 10,060,176		$ 9,894,703	
86								
87	**Maintenance**							
88	Maintenance Supervision and Engineering	568	SD-67	SD-68	$ 862		$ 862	SD-67
89	Maintenance of Structures	569	SD-67	SD-68	10,687		10,687	SD-67
90	Maintenance of Station Equipment	570	SD-67	SD-68	2,084,607		2,084,607	SD-67
91	Maintenance of Overhead Lines	571	SD-67	SD-68	160,454		160,454	
92	Maintenance of Underground Lines	572			-		-	
93	Maintenance of Miscellaneous Transmission Plant	573	SD-67	SD-68	6,948		6,948	
94					$ 2,263,559		$ 2,263,559	
95								
96	**Total Transmission Expenses**				**$ 12,323,735**		**$ 12,158,262**	
97								
98	**Distribution Expenses**							
99	**Operation**							
100	Operations Supervision and Engineering	580	SD-67	SD-68	$ 8,757,146	$ (43,375)	$ 8,713,771	SD-67
101	Load Dispatching	581	SD-67	SD-68	1,280,524		1,280,524	SD-67
102	Station Expenses	582	SD-67	SD-68	60,421		60,421	SD-67
103	Overhead Line Expenses	583	SD-67	SD-68	10,556,080	11,755	10,567,835	SD-67
104	Underground Line Expenses	584	SD-67	SD-68	6,175,800	52,538	6,228,338	SD-67
105	Street Lighting	585	SD-67	SD-68	743,836		743,836	SD-67
106	Meter Expenses	586	SD-67	SD-68	3,131,449		3,131,449	SD-67
107	Customer Installation Expenses	587			-		-	
108	Miscellaneous Distribution Expenses	588	SD-67	SD-68	2,432,330		2,432,330	SD-67
109	Rents	589			-		-	SD-67
110					$ 33,137,585		$ 33,158,503	
111								
112	**Maintenance**							
113	Maintenance Supervision and Engineering	590	SD-67	SD-68	$ 132,140		$ 132,140	
114	Maintenance of Structures	591			-		-	
115	Maintenance of Station Equipment	592	SD-67	SD-68	1,407,842		1,407,842	SD-67
116	Maintenance of Overhead Lines	593	SD-67	SD-68	1,140,375		1,140,375	SD-67
117	Maintenance of Underground Lines	594	SD-67	SD-68	45,878		45,878	SD-67
118	Maintenance of Line Transformers	595	SD-67	SD-68	8,052		8,052	SD-67
119	Maintenance of Street Lighting and Signal Systems	596	SD-67	SD-68	627,687		627,687	SD-67
120	Maintenance of Meters	597	SD-67	SD-68	68,127		68,127	
121	Maintenance of Miscellaneous Distribution Plant	598	SD-67	SD-68	952,146		952,146	SD-67
122					$ 4,382,247		$ 4,382,247	
123								
124	**Total Distribution Expenses**				**$ 37,519,832**		**$ 37,540,750**	
125								
126	**Customer and Information Expenses**							
127								
128	Customer Accounts Expenses							
129	Supervision	901	SD-67	SD-68	$ 200,796	$ 26,533	$ 227,329	
130	Meter Reading Expenses	902	SD-67	SD-68	3,766,648	(2,295)	3,764,353	
131	Customer Records and Collection Expenses	903	SD-67	SD-68	14,092,904	(23,741)	14,069,163	
132	Uncollectible Accounts	904			-		-	
133	Miscellaneous Customer Accounts Expenses	905			-		-	
134					$ 18,060,348		$ 18,060,845	
135								
136	Cust. Service & Information Expense							
137	Supervision	907	SD-67	SD-68	$ 1,781,257	$ (3,007)	$ 1,778,250	SD-67
138	Customer Assistance Expenses	908	SD-67	SD-68	3,768,518	484	3,769,002	SD-67
139	Informational & Instructional Advertising Expenses	909	SD-67	SD-68	7,803		7,803	
140	Misc Customer Service & Informational Expenses	910	SD-67	SD-68	534,644		534,644	
141	Supervision	911	SD-67	SD-68	4,661,831	(49,335)	4,612,496	SD-67
142	Demonstrating & Selling Expense	912	SD-67	SD-68	2,450,945		2,450,945	
143	Advertising Expense	913	SD-67	SD-68	292,728		292,728	
144	Miscellaneous Sales Expense	916	SD-67	SD-68	2,540		2,540	
145					$ 13,500,265		$ 13,448,407	
146								
147	**Total Customer and Information Expenses**				**$ 31,560,614**		**$ 31,509,253**	
148								
149	**General and Administrative Expenses**							
150	Administrative and General Salaries	920	SD-67	SD-68	$ 36,653,795	$ (166,074)	$ 36,487,721	SD-67
151	Office Supplies and Expenses	921	SD-67	SD-68	18,017		18,017	
152	Administrative Expense Transferred	922			-		-	
153	Outside Services Employed	923	SD-67	SD-68	4,407		4,407	
154	Property Insurance	924			-		-	
155	Injuries and Damages	925	SD-67	SD-68	12,972		12,972	
156	Employee Pension and Benefits	926	SD-67	SD-68	17,510,842	(17,510,842)	-	
157	Regulatory Commission Expense	928			-		-	
158	General Expenses	930	SD-67	SD-68	907,996		907,996	SD-67
159	Rents	931			-		-	
160	Maintenance of General Plant	935	SD-67	SD-68	112		112	SD-67

Work Paper 3.2 - Labor

Purpose: Develop Known and Measurable Adjustments to Remove GAAP Adjustments to Labor Costs in FY 2009 and Reflect Increases in Employee Benefit Costs (e.g., Health, Retirement) and a General Wage Increase Effective at the Beginning of FY 2011

Line No.		FERC Account	with GAAP Source Reference	w/o GAAP Source Reference	FY 2009 Actual with GAAP	Remove GAAP Adjustments	FY 2009 Actual w/o GAAP	Capitalized Source Reference
A		B	C	D	E	F	G	H
161					$ 55,108,140		$ 37,431,224	
162								
163	**Total Electric Labor**				**$ 158,051,114**		**$ 140,007,431**	
164								
165								
166	**Non-Electric Utility Labor**							
167	Expenses - Non-utility operations	417	SD-67	SD-68	$ 7,541,084	$ (39,595)	$ 7,501,489	SD-67
168					$ 7,541,084		$ 7,501,489	
169								
170	**Total Labor (Including Non-Electric Labor)**				**$ 165,592,199**		**$ 147,508,920**	
171								
172								
173								
174								
175								

Work Paper 3.2 - Labor

Purpose: Develop Known and Measurable Adjustments to Remove GAAP Adju
Retirement) and a General Wage Increase Effective at the Beginning

Line No.		FERC Account	FY 2009 Capitalized Portion	FY 2009 Net of Capitalization	FY 2011 Source Reference	FY 2011 Labor Budget Estimate [1, 2]	FY 2011 Capitalized Estimate Based on FY 2009	FY 2011 Labor Budget Net of Capitalization
A		B	I	J	K	L	M	N
1	**Power Production Expenses**							
2	Steam Power Generation							
3	**Operation**							
4	Operation Supervision and Engineering	500	$ 193,634	$ 6,501,219	SD-69	$ 6,942,626	$ 200,800	$ 6,741,825
5	Fuel	501	-	622,121	SD-69	662,876	-	662,876
6	Steam Expenses	502	-	2,590,796	SD-69	2,722,998	-	2,722,998
7	Steam from other Sources	503	-	-		-	-	-
8	Steam Transferred	504	-	-		-	-	-
9	Electric Expenses	505	-	18,735	SD-69	20,564	-	20,564
10	Miscellaneous Steam Expenses	506	4,310	421,006	SD-69	429,536	4,353	425,183
11	Rents	507	-	-		-	-	-
12			$ 197,944	$ 10,153,878		$ 10,778,599	$ 205,153	$ 10,573,446
13								
14	**Maintenance**							
15	Maintenance Supervision	510	$ 6,499	$ 2,106,376	SD-69	$ 2,225,584	$ 6,846	$ 2,218,738
16	Maintenance of Structures	511	-	14,957	SD-69	17,925	-	17,925
17	Maintenance of Boiler Plant	512	-	242,292	SD-69	267,222	-	267,222
18	Maintenance of Electric Plant	513	32,808	316,373	SD-69	372,267	34,977	337,290
19	Maintenance of Miscellaneous Steam Plant	514	1,996	1,020,343	SD-69	1,086,577	2,121	1,084,456
20	Rents	515	-	-		-	-	-
21			$ 41,303	$ 3,700,341		$ 3,969,575	$ 43,945	$ 3,925,630
22								
23	Nuclear Power Generation							
24	**Operation**							
25	Operation Supervision	517	$ -	$ 249,552	SD-69	$ 275,541	$ -	$ 275,541
26	Nuclear Fuel Expense	518	-	-		-	-	-
27	Coolants and Water	519	-	-		-	-	-
28	Steam Expenses	520	-	-		-	-	-
29	Electric Expenses	523	-	-		-	-	-
30	Misc Nuclear Power Expenses	524	-	-		-	-	-
31	Rents	525	-	-		-	-	-
32			$ -	$ 249,552		$ 275,541	$ -	$ 275,541
33								
34	**Maintenance**							
35	Maintenance Supervision	528	$ -	$ -		$ -	$ -	$ -
36	Maintenance of Structures	529	-	-		-	-	-
37	Maintenance of Reactor Plant	530	-	-		-	-	-
38	Maintenance of Electric Plant	531	-	-		-	-	-
39	Maintenance of Miscellaneous	532	-	-		-	-	-
40			$ -	$ -		$ -	$ -	$ -
41								
42	Hydraulic Power Generation							
43	**Maintenance**							
44	Maintenance Supervision	541	$ -	$ -		$ -	$ -	$ -
45	Maintenance of Structures	542	-	-		-	-	-
46	Maintenance of Reservoirs, Dams & Waterways	543	-	-		-	-	-
47	Maintenance of Electric Plant	544	-	-		-	-	-
48	Maintenance of Miscellaneous Hydraulic Plant	545	-	-		-	-	-
49			$ -	$ -		$ -	$ -	$ -
50								
51	Other Power Generation							
52	**Operation**							
53	Operation Supervision	546	$ 4,328	$ 1,382,607	SD-69	$ 1,410,752	$ 4,402	$ 1,406,349
54	Fuel	547	-	-		-	-	-
55	Generation Expenses	548	-	1,914,018	SD-69	1,973,487	-	1,973,487
56	Miscellaneous Other Power Generation Expenses	549	-	44,699	SD-69	54,412	-	54,412
57	Rents	550	-	89	SD-69	15	-	15
58			$ 4,328	$ 3,341,413		$ 3,438,665	$ 4,402	$ 3,434,262
59								
60	**Maintenance**							
61	Maintenance Supervision and Engineering	551	$ 189	$ 21,883	SD-69	$ 20,665	$ 177	$ 20,489
62	Maintenance of Structures	552	-	34,624	SD-69	41,894	-	41,894
63	Maintenance of Generating and Electric Equipment	553	65,872	826,209	SD-69	1,003,309	74,085	929,224
64	Maintenance of Misc Other Power Generation Plant	554	51,786	670,515	SD-69	749,711	53,751	695,960
65			$ 117,847	$ 1,553,231		$ 1,815,579	$ 128,013	$ 1,687,566
66								
67	Other Power Supply							
68	Purchased Power	555	$ -	$ -		$ -	$ -	$ -
69	System Control and Load Dispatching	556	-	1,577,602	SD-69	1,657,074	-	1,657,074
70	Other Power Expenses	557	-	430,503	SD-69	446,051	-	446,051
71			$ -	$ 2,008,106		$ 2,103,125	$ -	$ 2,103,125
72								
73	**Total Power Production Expense**		**$ 361,422**	**$ 21,006,520**		**$ 22,381,085**	**$ 381,513**	**$ 21,999,572**
74								
75	**Transmission Expense**							
76	**Operation**							
77	Operations Supervision and Engineering	560	$ 1,405,154	$ 5,202,212	SD-69	$ 6,491,948	$ 1,380,609	$ 5,111,339
78	Load Dispatching	561	116	1,525,475	SD-69	1,582,800	120	1,582,680
79	Station Expenses	562	214,347	73,258	SD-69	328,198	244,601	83,598
80	Overhead Line Expenses	563	897,535	476,552	SD-69	1,582,300	1,033,537	548,764

Work Paper 3.2 - Labor

Purpose: Develop Known and Measurable Adjustments to Remove GAAP Adju
Retirement) and a General Wage Increase Effective at the Beginning

Line No.		FERC Account	FY 2009 Capitalized Portion	FY 2009 Net of Capitalization	FY 2011 Source Reference	FY 2011 Labor Budget Estimate [1,2]	FY 2011 Capitalized Estimate Based on FY 2009	FY 2011 Labor Budget Net of Capitalization
A		B	I	J	K	L	M	N
81	Underground Line Expenses	564	210	-		-	-	-
82	Transmission of Electricity by Others	565	-	87	SD-69	105	-	105
83	Miscellaneous Transmission Expenses	566	3,649	96,109	SD-69	113,566	4,154	109,413
84	Rents	567	-	-		-	-	-
85			$ 2,521,011	$ 7,373,692		$ 10,098,917	$ 2,663,021	$ 7,435,897
86								
87	**Maintenance**							
88	Maintenance Supervision and Engineering	568	$ 808	$ 54	SD-69	$ 1,050	$ 985	$ 66
89	Maintenance of Structures	569	8,872	1,815	SD-69	11,671	9,688	1,982
90	Maintenance of Station Equipment	570	1,310,271	774,336	SD-69	2,356,539	1,481,193	875,347
91	Maintenance of Overhead Lines	571	-	160,454	SD-69	179,242	-	179,242
92	Maintenance of Underground Lines	572	-	-		-	-	-
93	Maintenance of Miscellaneous Transmission Plant	573	-	6,948	SD-69	3,542	-	3,542
94			$ 1,319,951	$ 943,608		$ 2,552,045	$ 1,491,866	$ 1,060,179
95								
96	**Total Transmission Expenses**		**$ 3,840,962**	**$ 8,317,300**		**$ 12,650,962**	**$ 4,154,886**	**$ 8,496,076**
97								
98	**Distribution Expenses**							
99	**Operation**							
100	Operations Supervision and Engineering	580	$ 248,073	$ 8,465,698	SD-69	$ 7,987,467	$ 227,396	$ 7,760,072
101	Load Dispatching	581	39,711	1,240,813	SD-69	1,236,455	38,344	1,198,111
102	Station Expenses	582	19,895	40,526	SD-69	71,059	23,398	47,661
103	Overhead Line Expenses	583	5,298,378	5,269,457	SD-69	11,397,906	5,714,549	5,683,357
104	Underground Line Expenses	584	4,041,683	2,186,654	SD-69	6,862,142	4,452,970	2,409,171
105	Street Lighting	585	386,443	357,393	SD-69	625,783	325,111	300,672
106	Meter Expenses	586	371,714	2,759,735	SD-69	3,264,343	387,489	2,876,854
107	Customer Installation Expenses	587	-	-		-	-	-
108	Miscellaneous Distribution Expenses	588	919,652	1,512,678	SD-69	2,503,291	946,482	1,556,809
109	Rents	589	627	(627)		-	-	-
110			$ 11,326,175	$ 21,832,328		$ 33,948,447	$ 12,115,740	$ 21,832,708
111								
112	**Maintenance**							
113	Maintenance Supervision and Engineering	590	$ -	$ 132,140	SD-69	$ 142,290	$ -	$ 142,290
114	Maintenance of Structures	591	-	-		-	-	-
115	Maintenance of Station Equipment	592	219,835	1,188,007	SD-69	1,612,255	251,754	1,360,500
116	Maintenance of Overhead Lines	593	128,275	1,012,100	SD-69	1,137,430	127,944	1,009,486
117	Maintenance of Underground Lines	594	45,467	411	SD-69	53,058	52,582	476
118	Maintenance of Line Transformers	595	682	7,370	SD-69	9,101	771	8,330
119	Maintenance of Street Lighting and Signal Systems	596	828	626,859	SD-69	746,299	984	745,315
120	Maintenance of Meters	597	-	68,127	SD-69	79,995	-	79,995
121	Maintenance of Miscellaneous Distribution Plant	598	3,790	948,356	SD-69	1,037,349	4,129	1,033,220
122			$ 398,877	$ 3,983,370		$ 4,817,777	$ 438,165	$ 4,379,612
123								
124	**Total Distribution Expenses**		**$ 11,725,052**	**$ 25,815,697**		**$ 38,766,225**	**$ 12,553,905**	**$ 26,212,320**
125								
126	**Customer and Information Expenses**							
127								
128	Customer Accounts Expenses							
129	Supervision	901	$ -	$ 227,329	SD-69	$ 230,365	$ -	$ 230,365
130	Meter Reading Expenses	902	-	3,764,353	SD-69	3,938,836	-	3,938,836
131	Customer Records and Collection Expenses	903	-	14,069,163	SD-69	14,772,673	-	14,772,673
132	Uncollectible Accounts	904	-	-		-	-	-
133	Miscellaneous Customer Accounts Expenses	905	-	-		-	-	-
134			$ -	$ 18,060,845		$ 18,941,874	$ -	$ 18,941,874
135								
136	Cust. Service & Information Expense							
137	Supervision	907	$ 1,721	$ 1,776,529	SD-69	$ 1,898,246	$ 1,837	$ 1,896,409
138	Customer Assistance Expenses	908	378	3,768,624	SD-69	3,989,270	400	3,988,870
139	Informational & Instructional Advertising Expenses	909	-	7,803	SD-69	7,638	-	7,638
140	Misc Customer Service & Informational Expenses	910	-	534,644	SD-69	569,986	-	569,986
141	Supervision	911	105,263	4,507,233	SD-69	4,814,650	109,877	4,704,773
142	Demonstrating & Selling Expense	912	-	2,450,945	SD-69	2,665,522	-	2,665,522
143	Advertising Expense	913	-	292,728	SD-69	329,768	-	329,768
144	Miscellaneous Sales Expense	916	-	2,540		-	-	-
145			$ 107,362	$ 13,341,046		$ 14,275,078	$ 112,113	$ 14,162,965
146								
147	**Total Customer and Information Expenses**		**$ 107,362**	**$ 31,401,891**		**$ 33,216,952**	**$ 112,113**	**$ 33,104,839**
148								
149	**General and Administrative Expenses**							
150	Administrative and General Salaries	920	$ 21,396	$ 36,466,324	SD-69	$ 42,593,484	$ 24,977	$ 42,568,507
151	Office Supplies and Expenses	921	-	18,017	SD-69	14,273	-	14,273
152	Administrative Expense Transferred	922	-	-		-	-	-
153	Outside Services Employed	923	-	4,407	SD-69	4,590	-	4,590
154	Property Insurance	924	-	-		-	-	-
155	Injuries and Damages	925	-	12,972		-	-	-
156	Employee Pension and Benefits	926	-	-		-	-	-
157	Regulatory Commission Expense	928	-	-		-	-	-
158	General Expenses	930	38,862	869,134	SD-69	1,048,137	44,860	1,003,277
159	Rents	931	-	-		-	-	-
160	Maintenance of General Plant	935	112	-	SD-69	136	136	-

Work Paper 3.2 - Labor

Purpose: Develop Known and Measurable Adjustments to Remove GAAP Adju
Retirement) and a General Wage Increase Effective at the Beginning

Line No.		FERC Account	FY 2009 Capitalized Portion	FY 2009 Net of Capitalization	FY 2011 Source Reference	FY 2011 Labor Budget Estimate [1, 2]	FY 2011 Capitalized Estimate Based on FY 2009	FY 2011 Labor Budget Net of Capitalization
A		B	I	J	K	L	M	N
161			$ 60,370	$ 37,370,853		$ 43,660,620	$ 69,973	$ 43,590,647
162								
163	**Total Electric Labor**		**$ 16,095,169**	**$ 123,912,262**		**$ 150,675,844**	**$ 17,272,391**	**$ 133,403,453**
164								
165								
166	**Non-Electric Utility Labor**							
167	Expenses - Non-utility operations	417	$ 160,345	$ 7,341,145	SD-69	$ 7,925,797	$ 169,414	$ 7,756,383
168			$ 160,345	$ 7,341,145		$ 7,925,797	$ 169,414	$ 7,756,383
169								
170	**Total Labor (Including Non-Electric Labor)**		**$ 16,255,513**	**$ 131,253,407**		**$ 158,601,641**	**$ 17,441,805**	**$ 141,159,836**
171								
172			Notes:					
173				[1] FY 2011 labor budget is net of 4.64% vacancy				
174				[2] Terminal pay is not budgeted. The amount listed for the FY 2011 labor budget includes an				
175				assumed terminal pay equal to the five-year average of 2006 through 2010.				

Work Paper 4 - Square Footage

Purpose: Functionalize Useable Square Footage to Use for Allocations

Line No.	Building	Square Feet Source Reference	Useable Square Feet	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A	B	C	D	E	F	G	H	I	J
1	Billing Services	WP 4.1	7,505	Customer	-	-	-	7,505	7,505
2	Customer Service	WP 4.1	15,121	Customer	-	-	-	15,121	15,121
3	Distribution	WP 4.1	24,749	Distribution	-	-	24,749	-	24,749
4	Energy Services	WP 4.1	21,583	Distribution	-	-	21,583	-	21,583
5	Metering	WP 4.1	10,372	Distribution	-	-	10,372	-	10,372
6	Power Production & Generation	WP 4.1	44,336	Production	44,336	-	-	-	44,336
7	Purchasing & SMBR	WP 4.1	2,987	PLTXGNL-N	1,548	366	1,073	-	2,987
8	Support Services	WP 4.1	172,466	PLTXGNL-N	89,396	21,137	61,932	-	172,466
9	Transmission	WP 4.1	11,631	Transmission	-	11,631	-	-	11,631
10			310,751		135,281	33,135	119,710	22,626	310,751

Work Paper 4.1 - Square Footage

Purpose: Useable Square Footage to be Used for Allocation of Select Expenses

Line No.	Building	Source Reference	Billing Services	Customer Service	Distribution	Energy Services	Metering	Power Production & Generation	Purchasing & SMBR	Support Services	Transmission	Useable Square Feet
A	B	C	D	E	F	G	H	I	J	K	L	M
1	RLC	SD-10	-	-	-	-	7,213	-	-	-	-	7,213
2	Decker Power Plant	SD-10	-	-	-	-	-	1,149	-	-	-	1,149
3	Energy Control Center	SD-10	-	502	5,442	-	-	-	-	866	3,213	10,023
4	Holly Power Plant	SD-10	-	-	-	-	-	790	-	-	-	790
5	Kramer Service Center	SD-10	-	-	8,166	-	3,159	733	-	1,276	7,765	21,100
6	811 Barton Springs	SD-10	6,377	-	-	14,012	-	5,000	-	21,070	-	46,459
7	Mopac Steck	SD-10	-	-	-	-	-	-	-	26,618	-	26,618
8	St Elmo	SD-10	-	-	9,631	-	-	-	-	498	652	10,782
9	Rosewood Zaragosa	SD-10	-	820	-	-	-	-	-	-	-	820
10	TLC	SD-10	1,128	13,799	1,511	7,571	-	3,325	2,987	39,717	-	70,038
11	SCC	SD-10	-	-	-	-	-	-	-	-	-	-
12	Justin Lane-Warehouse	SD-10	-	-	-	-	-	33,339	-	33,339	-	66,677
13	Kramer Bldg D-Warehouse	SD-10	-	-	-	-	-	-	-	30,245	-	30,245
14	St. Elmo-Warehouse	SD-10	-	-	-	-	-	-	-	18,836	-	18,836
15			7,505	15,121	24,749	21,583	10,372	44,336	2,987	172,466	11,631	310,751

Work Paper 5 - Debt

Purpose: Identify and Functionalize the Accrual Basis Debt Service in FY 2011 for Inclusion in the Test Year

Line No.	Issue	Source Reference	FY 2009	FY 2010	FY 2011	Lien Status	Allocation Source Reference	Percentage Allocation Production	Transmission	Distribution	Customer	Non-Electric	Total
A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	**GO Series 1999**					**GO/CO**	WP 39	42.9%	12.2%	24.6%	20.3%	0.0%	100.0%
2	Principal	SD-11	$ 5,540	$ -	$ -								
3	Interest	SD-11	267	-	-								
4			$ 5,806	$ -	$ -								
5													
6	**GO Series 2003**					**GO/CO**	SD-76	0.0%	55.2%	44.8%	0.0%	0.0%	100.0%
7	Principal	SD-11	$ 148,387	$ 154,983	$ 13,101								
8	Interest	SD-11	8,961	4,356	1,326								
9			$ 157,348	$ 159,338	$ 14,428								
10													
11	**GO Series 2005**					**GO/CO**	WP 39	42.9%	12.2%	24.6%	20.3%	0.0%	100.0%
12	Principal	SD-11	$ -	$ 53,158	$ 63,177								
13	Interest	SD-11	51,099	50,878	48,178								
14			$ 51,099	$ 104,035	$ 111,355								
15													
16	**GO Series 2008**					**GO/CO**	WP 39	42.9%	12.2%	24.6%	20.3%	0.0%	100.0%
17	Principal	SD-11	$ 8,520	$ 8,583	$ 10,319								
18	Interest	SD-11	5,400	4,973	4,537								
19			$ 13,919	$ 13,556	$ 14,856								
20													
21	**Revenue Series 1990B (CAB)**					**Priority Lien (1)**	SD-12	59.5%	0.0%	40.5%	0.0%	0.0%	100.0%
22	Principal	SD-11	$ -	$ -	$ -								
23	Interest	SD-11	-	-	-								
24			$ -	$ -	$ -								
25													
26	**Revenue Series 1992**					**Priority Lien (1)**	SD-12	47.6%	27.1%	25.3%	0.0%	0.0%	100.0%
27	Principal	SD-11	$ 2,945,037	$ 3,710,617	$ 3,458,463								
28	Interest	SD-11	6,584,902	8,992,448	9,234,625								
29			$ 9,529,939	$ 12,703,065	$ 12,693,088								
30													
31	**Revenue Series 1992AR CAB**					**Priority Lien (1)**	SD-12	74.0%	16.3%	9.7%	0.0%	0.0%	100.0%
32	Principal	SD-11	$ 8,671,195	$ 8,110,473	$ 7,550,244								
33	Interest	SD-11	18,312,189	19,108,648	19,591,152								
34			$ 26,983,384	$ 27,219,121	$ 27,141,396								
35													
36	**Revenue Series 1993**					**Priority Lien (1)**	SD-12	66.1%	25.0%	8.8%	0.0%	0.0%	100.0%
37	Principal	SD-11	$ -	$ -	$ 6,982,792								
38	Interest	SD-11	1,600,800	1,509,975	1,196,394								
39			$ 1,600,800	$ 1,509,975	$ 8,179,186								
40													
41	**Revenue Series 1993 CAB**					**Priority Lien (1)**	SD-12	66.1%	25.0%	8.8%	0.0%	0.0%	100.0%
42	Principal	SD-11	$ 2,806,514	$ 2,481,555	$ 125,255								
43	Interest	SD-11	4,876,724	4,764,389	250,897								
44			$ 7,683,238	$ 7,245,944	$ 376,152								
45													
46	**Revenue Series 1993A CAB**					**Priority Lien (1)**	SD-12	78.7%	12.2%	9.1%	0.0%	0.0%	100.0%
47	Principal	SD-11	$ 2,842,646	$ 2,646,277	$ 327,228								
48	Interest	SD-11	4,356,257	4,517,369	579,246								
49			$ 7,198,903	$ 7,163,646	$ 906,474								
50													
51	**Revenue Series 1996A**					**Priority Lien (1)**	SD-12	94.9%	2.0%	3.2%	0.0%	0.0%	100.0%

Work Paper 5 - Debt

Purpose: Identify and Functionalize the Accrual Basis Debt Service in FY 2011 for Inclusion in the Test Year

Line No.	Issue	Source Reference	FY 2009	FY 2010	FY 2011	Lien Status	Allocation Source Reference	Percentage Allocation Production	Transmission	Distribution	Customer	Non-Electric	Total
A	B	C	D	E	F	G	H	I	J	K	L	M	N
52	Principal	SD-11	$ 14,075,000	$ -	$ -								
53	Interest	SD-11	431,047	-	-								
54			$ 14,506,047	$ -	$ -								
55													
56	**Revenue Series 1998 PRIOR LIEN**					**Priority Lien (1)**	SD-12	95.8%	2.1%	2.0%	0.0%	0.0%	100.0%
57	Principal	SD-11	$ 13,655,421	$ 14,610,596	$ 15,634,074								
58	Interest	SD-11	4,266,888	3,339,527	2,345,115								
59			$ 17,922,308	$ 17,950,122	$ 17,979,189								
60													
61	**Revenue Series 1998 SUBORDINATE LIEN**					**Subordinate Lien (2)**	SD-12	1.3%	32.8%	65.9%	0.0%	0.0%	100.0%
62	Principal	SD-11	$ 1,113,364	$ 931,515	$ 916,670								
63	Interest	SD-11	5,376,271	5,329,402	5,280,789								
64			$ 6,489,635	$ 6,260,917	$ 6,197,459								
65													
66	**Revenue Series 2001**					**Separate Lien (3)**	SD-12	0.0%	0.0%	100.0%	0.0%	0.0%	100.0%
67	Principal	SD-11	$ 2,300,000	$ 3,050,000	$ 775,000								
68	Interest	SD-11	3,898,125	2,567,063	28,094								
69			$ 6,198,125	$ 5,617,063	$ 803,094								
70													
71	**Revenue Series 2002**					**Separate Lien (3)**	SD-12	39.0%	21.7%	39.3%	0.0%	0.0%	100.0%
72	Principal	SD-11	$ 4,258,750	$ 4,558,750	$ 5,105,000								
73	Interest	SD-11	3,050,791	2,839,136	2,596,094								
74			$ 7,309,541	$ 7,397,886	$ 7,701,094								
75													
76	**Revenue Series 2002A**					**Separate Lien (3)**	SD-12	59.3%	22.8%	17.9%	0.0%	0.0%	100.0%
77	Principal	SD-11	$ 3,273,750	$ 183,750	$ 188,750								
78	Interest	SD-11	5,096,392	5,007,700	5,000,325								
79			$ 8,370,142	$ 5,191,450	$ 5,189,075								
80													
81	**Revenue Series 2003**					**Separate Lien (3)**	SD-12	0.0%	46.4%	53.6%	0.0%	0.0%	100.0%
82	Principal	SD-11	$ 4,950,000	$ 5,150,000	$ 5,425,000								
83	Interest	SD-11	7,650,500	7,407,750	7,149,000								
84			$ 12,600,500	$ 12,557,750	$ 12,574,000								
85													
86	**Revenue Series 2006**					**Separate Lien (3)**	SD-12	0.0%	27.5%	72.5%	0.0%	0.0%	100.0%
87	Principal	SD-11	$ 2,975,000	$ 3,150,000	$ 3,275,000								
88	Interest	SD-11	7,369,500	7,223,750	7,065,000								
89			$ 10,344,500	$ 10,373,750	$ 10,340,000								
90													
91	**Revenue Series 2006A**					**Separate Lien (3)**	SD-12	49.9%	7.2%	42.9%	0.0%	0.0%	100.0%
92	Principal	SD-11	$ 12,802,500	$ 14,246,250	$ 12,795,000								
93	Interest	SD-11	6,890,000	6,143,188	5,454,406								
94			$ 19,692,500	$ 20,389,438	$ 18,249,406								
95													
96	**Revenue Series 2007**					**Separate Lien (3)**	SD-12	75.8%	19.3%	4.8%	0.0%	0.0%	100.0%
97	Principal	SD-11	$ 298,750	$ 6,750,000	$ 11,250,000								
98	Interest	SD-11	7,173,469	7,166,000	6,772,250								
99			$ 7,472,219	$ 13,916,000	$ 18,022,250								
100													
101	**Revenue Series 2008**					**Separate Lien (3)**	SD-12	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%
102	Principal	SD-11	$ 813,750	$ 1,111,250	$ 1,150,000								

Work Paper 5 - Debt

Purpose: Identify and Functionalize the Accrual Basis Debt Service in FY 2011 for Inclusion in the Test Year

Line No.	Issue	Source Reference	FY 2009	FY 2010	FY 2011	Lien Status	Allocation Source Reference	Percentage Allocation					
								Production	Transmission	Distribution	Customer	Non-Electric	Total
A	B	C	D	E	F	G	H	I	J	K	L	M	N
103	Interest	SD-11	3,029,207	2,851,917	2,816,097								
104			$ 3,842,957	$ 3,963,167	$ 3,966,097								
105													
106	**Revenue Series 2008A**					**Separate Lien (3)**	SD-12	34.0%	10.9%	55.1%	0.0%	0.0%	100.0%
107	Principal	SD-11	$ -	$ 150,000	$ 200,000								
108	Interest	SD-11	8,837,990	9,222,250	9,215,250								
109			$ 8,837,990	$ 9,372,250	$ 9,415,250								
110													
111	**Series 2010A CP refunding**					**Separate Lien (3)**	SD-12	62.6%	5.9%	31.5%	0.0%	0.0%	100.0%
112	Principal	SD-11	$ -	$ -	$ -								
113	Interest	SD-11	-	760,892	2,202,256								
114			$ -	$ 760,892	$ 2,202,256								
115													
116	**Series 2010A Tax Exempt refunding**					**Separate Lien (3)**	SD-12	4.6%	1.7%	93.6%	0.0%	0.0%	100.0%
117	Principal	SD-11	$ -	$ -	$ -								
118	Interest	SD-11	-	1,187,040	3,435,659								
119			$ -	$ 1,187,040	$ 3,435,659								
120													
121	**Series 2010B BAB CP refunding**					**Separate Lien (3)**	SD-12	50.6%	7.8%	41.6%	0.0%	0.0%	100.0%
122	Principal	SD-11	$ -	$ -	$ -								
123	Interest	SD-11	-	1,212,316	3,621,321								
124			$ -	$ 1,212,316	$ 3,621,321								
125													
126	**Capital Lease**					**Capital Lease**	SD-12	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%
127	Principal	SD-11	$ 30,649	$ 36,371	$ 38,231								
128	Interest	SD-11	78,263	78,863	77,792								
129			$ 108,912	$ 115,233	$ 116,023								
130													
131	**Series FPP Scrubber**					**Separate Lien (3)**	SD-12	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
132	Principal	WP 5.1	$ -	$ -	$ 715,064								
133	Interest	WP 5.1	-	-	1,972,045								
134			$ -	$ -	$ 2,687,109								
135													
136	**Commercial Paper in FY 2011**					**Commercial Paper**	WP 14.1	28.2%	12.1%	41.5%	18.2%	0.0%	100.0%
137	Principal		$ -	$ -	$ -								
138	Interest	WP 5.2	-	-	216,193								
139			$ -	$ -	$ 216,193								
140													
141	**Debt Total**												
142	Principal		$ 77,974,772	$ 71,094,126	$ 75,998,369								
143	Interest		98,945,041	101,289,828	96,154,041								
144			**$ 176,919,813**	**$ 172,383,954**	**$ 172,152,410**								
145													
146													
147													
148	**Priority Lien (1)**												
149	Principal		$ 44,995,813	$ 31,559,518	$ 34,078,056								
150	Interest		40,428,806	42,232,356	33,197,429								
151			$ 85,424,619	$ 73,791,873	$ 67,275,485								
152													

Work Paper 5 - Debt

Purpose: Identify and Functionalize the Accrual Basis Debt Service in FY 2011 for Inclusion in the Test Year

Line No.	Issue	Source Reference	FY 2009	FY 2010	FY 2011	Lien Status	Allocation Source Reference	Percentage Allocation					
								Production	Transmission	Distribution	Customer	Non-Electric	Total
A	B	C	D	E	F	G	H	I	J	K	L	M	N
153	**Subordinate Lien (2)**												
154	Principal		$ 1,113,364	$ 931,515	$ 916,670								
155	Interest		5,376,271	5,329,402	5,280,789								
156			$ 6,489,635	$ 6,260,917	$ 6,197,459								
157													
158	**Separate Lien (3)**												
159	Principal		$ 31,672,500	$ 38,350,000	$ 40,878,814								
160	Interest		52,995,974	53,589,001	57,327,796								
161			$ 84,668,474	$ 91,939,001	$ 98,206,610								
162													
163	**GO/CO**												
164	Principal		$ 162,446	$ 216,723	$ 86,598								
165	Interest		65,727	60,207	54,042								
166			$ 228,173	$ 276,930	$ 140,639								
167													
168	**Capital Lease**												
169	Principal		$ 30,649	$ 36,371	$ 38,231								
170	Interest		78,263	78,863	77,792								
171			$ 108,912	$ 115,233	$ 116,023								
172													
173	**Commercial Paper**												
174	Principal		$ -	$ -	$ -								
175	Interest		-	-	216,193								
176			$ -	$ -	$ 216,193								

Work Paper 5 - Debt

Line No.	Issue	Source Reference	FY 2009 Production	FY 2009 Transmission	FY 2009 Distribution	FY 2009 Customer	FY 2009 Non-Electric	FY 2009 Total	FY 2011 Production	FY 2011 Transmission	FY 2011 Distribution	FY 2011 Customer	FY 2011 Non-Electric	FY 2011 Total
A	B	C	O	P	Q	R	S	T	U	V	W	X	Y	Z
1	**GO Series 1999**													
2	Principal	SD-11	$ 2,378	$ 676	$ 1,361	$ 1,125	$ -	$ 5,540	$ -	$ -	$ -	$ -	$ -	$ -
3	Interest	SD-11	114	33	66	54	-	267	-	-	-	-	-	-
4			$ 2,492	$ 709	$ 1,427	$ 1,179	$ -	$ 5,806	$ -	$ -	$ -	$ -	$ -	$ -
5														
6	**GO Series 2003**													
7	Principal	SD-11	$ -	$ 81,922	$ 66,465	$ -	$ -	$ 148,387	$ -	$ 7,233	$ 5,868	$ -	$ -	$ 13,101
8	Interest	SD-11	-	4,947	4,014	-	-	8,961	-	732	594	-	-	1,326
9			$ -	$ 86,869	$ 70,479	$ -	$ -	$ 157,348	$ -	$ 7,965	$ 6,462	$ -	$ -	$ 14,428
10														
11	**GO Series 2005**													
12	Principal	SD-11	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,115	$ 7,714	$ 15,522	$ 12,826	$ -	$ 63,177
13	Interest	SD-11	21,931	6,239	12,554	10,374	-	51,099	20,678	5,883	11,837	9,781	-	48,178
14			$ 21,931	$ 6,239	$ 12,554	$ 10,374	$ -	$ 51,099	$ 47,793	$ 13,597	$ 27,359	$ 22,607	$ -	$ 111,355
15														
16	**GO Series 2008**													
17	Principal	SD-11	$ 3,657	$ 1,040	$ 2,093	$ 1,730	$ -	$ 8,520	$ 4,429	$ 1,260	$ 2,535	$ 2,095	$ -	$ 10,319
18	Interest	SD-11	2,317	659	1,327	1,096	-	5,400	1,947	554	1,115	921	-	4,537
19			$ 5,974	$ 1,700	$ 3,420	$ 2,826	$ -	$ 13,919	$ 6,376	$ 1,814	$ 3,650	$ 3,016	$ -	$ 14,856
20														
21	**Revenue Series 1990B (CAB)**													
22	Principal	SD-11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Interest	SD-11	-	-	-	-	-	-	-	-	-	-	-	-
24			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25														
26	**Revenue Series 1992**													
27	Principal	SD-11	$ 1,401,415	$ 799,215	$ 744,407	$ -	$ -	$ 2,945,037	$ 1,645,732	$ 938,547	$ 874,184	$ -	$ -	$ 3,458,463
28	Interest	SD-11	3,133,469	1,786,990	1,664,443	-	-	6,584,902	4,394,357	2,506,064	2,334,204	-	-	9,234,625
29			$ 4,534,884	$ 2,586,205	$ 2,408,850	$ -	$ -	$ 9,529,939	$ 6,040,090	$ 3,444,611	$ 3,208,388	$ -	$ -	$ 12,693,088
30														
31	**Revenue Series 1992AR CAB**													
32	Principal	SD-11	$ 6,417,537	$ 1,412,822	$ 840,836	$ -	$ -	$ 8,671,195	$ 5,587,923	$ 1,230,182	$ 732,139	$ -	$ -	$ 7,550,244
33	Interest	SD-11	13,552,822	2,983,655	1,775,712	-	-	18,312,189	14,499,380	3,192,040	1,899,732	-	-	19,591,152
34			$ 19,970,359	$ 4,396,477	$ 2,616,548	$ -	$ -	$ 26,983,384	$ 20,087,304	$ 4,422,222	$ 2,631,870	$ -	$ -	$ 27,141,396
35														
36	**Revenue Series 1993**													
37	Principal	SD-11	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,617,030	$ 1,748,815	$ 616,947	$ -	$ -	$ 6,982,792
38	Interest	SD-11	1,058,451	400,915	141,435	-	-	1,600,800	791,057	299,633	105,704	-	-	1,196,394
39			$ 1,058,451	$ 400,915	$ 141,435	$ -	$ -	$ 1,600,800	$ 5,408,087	$ 2,048,448	$ 722,652	$ -	$ -	$ 8,179,186
40														
41	**Revenue Series 1993 CAB**													
42	Principal	SD-11	$ 1,855,670	$ 702,881	$ 247,963	$ -	$ -	$ 2,806,514	$ 82,819	$ 31,370	$ 11,067	$ -	$ -	$ 125,255
43	Interest	SD-11	3,224,495	1,221,358	430,871	-	-	4,876,724	165,893	62,836	22,167	-	-	250,897
44			$ 5,080,165	$ 1,924,239	$ 678,833	$ -	$ -	$ 7,683,238	$ 248,712	$ 94,206	$ 33,234	$ -	$ -	$ 376,152
45														
46	**Revenue Series 1993A CAB**													
47	Principal	SD-11	$ 2,237,399	$ 346,462	$ 258,786	$ -	$ -	$ 2,842,646	$ 257,556	$ 39,883	$ 29,790	$ -	$ -	$ 327,228
48	Interest	SD-11	3,428,736	530,941	396,580	-	-	4,356,257	455,915	70,599	52,733	-	-	579,246
49			$ 5,666,135	$ 877,402	$ 655,366	$ -	$ -	$ 7,198,903	$ 713,470	$ 110,481	$ 82,523	$ -	$ -	$ 906,474
50														
51	**Revenue Series 1996A**													

Work Paper 5 - Debt

Line No.	Issue	Source Reference	FY 2009 Production	FY 2009 Transmission	FY 2009 Distribution	FY 2009 Customer	FY 2009 Non-Electric	FY 2009 Total	FY 2011 Production	FY 2011 Transmission	FY 2011 Distribution	FY 2011 Customer	FY 2011 Non-Electric	FY 2011 Total
A	B	C	O	P	Q	R	S	T	U	V	W	X	Y	Z
52	Principal	SD-11	$ 13,352,574	$ 276,899	$ 445,527	$ -	$ -	$ 14,075,000	$ -	$ -	$ -	$ -	$ -	$ -
53	Interest	SD-11	408,923	8,480	13,644	-	-	431,047	-	-	-	-	-	-
54			$ 13,761,497	$ 285,379	$ 459,172	$ -	$ -	$ 14,506,047	$ -	$ -	$ -	$ -	$ -	$ -
55														
56	**Revenue Series 1998 PRIOR LIEN**													
57	Principal	SD-11	$ 13,085,228	$ 292,980	$ 277,212	$ -	$ -	$ 13,655,421	$ 14,981,262	$ 335,433	$ 317,379	$ -	$ -	$ 15,634,074
58	Interest	SD-11	4,088,721	91,547	86,620	-	-	4,266,888	2,247,193	50,315	47,607	-	-	2,345,115
59			$ 17,173,949	$ 384,527	$ 363,832	$ -	$ -	$ 17,922,308	$ 17,228,455	$ 385,748	$ 364,986	$ -	$ -	$ 17,979,189
60														
61	**Revenue Series 1998 SUBORDINATI**													
62	Principal	SD-11	$ 13,949	$ 365,292	$ 734,123	$ -	$ -	$ 1,113,364	$ 11,485	$ 300,757	$ 604,428	$ -	$ -	$ 916,670
63	Interest	SD-11	67,359	1,763,942	3,544,970	-	-	5,376,271	66,162	1,732,615	3,482,012	-	-	5,280,789
64			$ 81,308	$ 2,129,234	$ 4,279,093	$ -	$ -	$ 6,489,635	$ 77,647	$ 2,033,372	$ 4,086,440	$ -	$ -	$ 6,197,459
65														
66	**Revenue Series 2001**													
67	Principal	SD-11	$ -	$ -	$ 2,300,000	$ -	$ -	$ 2,300,000	$ -	$ -	$ 775,000	$ -	$ -	$ 775,000
68	Interest	SD-11	-	-	3,898,125	-	-	3,898,125	-	-	28,094	-	-	28,094
69			$ -	$ -	$ 6,198,125	$ -	$ -	$ 6,198,125	$ -	$ -	$ 803,094	$ -	$ -	$ 803,094
70														
71	**Revenue Series 2002**													
72	Principal	SD-11	$ 1,662,884	$ 922,810	$ 1,673,056	$ -	$ -	$ 4,258,750	$ 1,993,313	$ 1,106,180	$ 2,005,507	$ -	$ -	$ 5,105,000
73	Interest	SD-11	1,191,221	661,063	1,198,508	-	-	3,050,791	1,013,679	562,536	1,019,879	-	-	2,596,094
74			$ 2,854,105	$ 1,583,872	$ 2,871,564	$ -	$ -	$ 7,309,541	$ 3,006,992	$ 1,668,716	$ 3,025,386	$ -	$ -	$ 7,701,094
75														
76	**Revenue Series 2002A**													
77	Principal	SD-11	$ 1,941,216	$ 745,701	$ 586,832	$ -	$ -	$ 3,273,750	$ 111,922	$ 42,994	$ 33,834	$ -	$ -	$ 188,750
78	Interest	SD-11	3,021,978	1,160,866	913,548	-	-	5,096,392	2,965,014	1,138,984	896,328	-	-	5,000,325
79			$ 4,963,194	$ 1,906,567	$ 1,500,381	$ -	$ -	$ 8,370,142	$ 3,076,936	$ 1,181,978	$ 930,162	$ -	$ -	$ 5,189,075
80														
81	**Revenue Series 2003**													
82	Principal	SD-11	$ -	$ 2,299,210	$ 2,650,790	$ -	$ -	$ 4,950,000	$ -	$ 2,519,841	$ 2,905,159	$ -	$ -	$ 5,425,000
83	Interest	SD-11	-	3,553,557	4,096,943	-	-	7,650,500	-	3,320,617	3,828,383	-	-	7,149,000
84			$ -	$ 5,852,767	$ 6,747,733	$ -	$ -	$ 12,600,500	$ -	$ 5,840,458	$ 6,733,542	$ -	$ -	$ 12,574,000
85														
86	**Revenue Series 2006**													
87	Principal	SD-11	$ -	$ 817,709	$ 2,157,292	$ -	$ -	$ 2,975,000	$ -	$ 900,167	$ 2,374,834	$ -	$ -	$ 3,275,000
88	Interest	SD-11	-	2,025,581	5,343,919	-	-	7,369,500	-	1,941,886	5,123,114	-	-	7,065,000
89			$ -	$ 2,843,289	$ 7,501,211	$ -	$ -	$ 10,344,500	$ -	$ 2,842,052	$ 7,497,948	$ -	$ -	$ 10,340,000
90														
91	**Revenue Series 2006A**													
92	Principal	SD-11	$ 6,384,493	$ 920,332	$ 5,497,676	$ -	$ -	$ 12,802,500	$ 6,380,752	$ 919,793	$ 5,494,455	$ -	$ -	$ 12,795,000
93	Interest	SD-11	3,435,982	495,301	2,958,718	-	-	6,890,000	2,720,064	392,100	2,342,242	-	-	5,454,406
94			$ 9,820,474	$ 1,415,632	$ 8,456,394	$ -	$ -	$ 19,692,500	$ 9,100,816	$ 1,311,893	$ 7,836,697	$ -	$ -	$ 18,249,406
95														
96	**Revenue Series 2007**													
97	Principal	SD-11	$ 226,513	$ 57,752	$ 14,485	$ -	$ -	$ 298,750	$ 8,529,785	$ 2,174,764	$ 545,451	$ -	$ -	$ 11,250,000
98	Interest	SD-11	5,438,947	1,386,720	347,802	-	-	7,173,469	5,134,741	1,309,160	328,349	-	-	6,772,250
99			$ 5,665,460	$ 1,444,472	$ 362,287	$ -	$ -	$ 7,472,219	$ 13,664,527	$ 3,483,923	$ 873,800	$ -	$ -	$ 18,022,250
100														
101	**Revenue Series 2008**													
102	Principal	SD-11	$ -	$ -	$ -	$ -	$ 813,750	$ 813,750	$ -	$ -	$ -	$ -	$ 1,150,000	$ 1,150,000

Work Paper 5 - Debt

Line No.	Issue	Source Reference	FY 2009						FY 2011					
			Production	Transmission	Distribution	Customer	Non-Electric	Total	Production	Transmission	Distribution	Customer	Non-Electric	Total
A	B	C	O	P	Q	R	S	T	U	V	W	X	Y	Z
103	Interest	SD-11	-	-	-	-	3,029,207	3,029,207	-	-	-	-	2,816,097	2,816,097
104			$ -	$ -	$ -	$ -	$ 3,842,957	$ 3,842,957	$ -	$ -	$ -	$ -	$ 3,966,097	$ 3,966,097
105														
106	**Revenue Series 2008A**													
107	Principal	SD-11	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,918	$ 21,798	$ 110,284	$ -	$ -	$ 200,000
108	Interest	SD-11	3,001,293	963,253	4,873,444	-	-	8,837,990	3,129,407	1,004,370	5,081,473	-	-	9,215,250
109			$ 3,001,293	$ 963,253	$ 4,873,444	$ -	$ -	$ 8,837,990	$ 3,197,325	$ 1,026,168	$ 5,191,757	$ -	$ -	$ 9,415,250
110														
111	**Series 2010A CP refunding**													
112	Principal	SD-11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
113	Interest	SD-11	-	-	-	-	-	-	1,378,392	130,153	693,710	-	-	2,202,256
114			$ -	$ -	$ -	$ -	$ -	$ -	$ 1,378,392	$ 130,153	$ 693,710	$ -	$ -	$ 2,202,256
115														
116	**Series 2010A Tax Exempt refunding**													
117	Principal	SD-11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118	Interest	SD-11	-	-	-	-	-	-	158,487	60,031	3,217,141	-	-	3,435,659
119			$ -	$ -	$ -	$ -	$ -	$ -	$ 158,487	$ 60,031	$ 3,217,141	$ -	$ -	$ 3,435,659
120														
121	**Series 2010B BAB CP refunding**													
122	Principal	SD-11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
123	Interest	SD-11	-	-	-	-	-	-	1,832,750	281,014	1,507,556	-	-	3,621,321
124			$ -	$ -	$ -	$ -	$ -	$ -	$ 1,832,750	$ 281,014	$ 1,507,556	$ -	$ -	$ 3,621,321
125														
126	**Capital Lease**													
127	Principal	SD-11	$ -	$ -	$ -	$ -	$ 30,649	$ 30,649	$ -	$ -	$ -	$ -	$ 38,231	$ 38,231
128	Interest	SD-11	-	-	-	-	78,263	78,263	-	-	-	-	77,792	77,792
129			$ -	$ -	$ -	$ -	$ 108,912	$ 108,912	$ -	$ -	$ -	$ -	$ 116,023	$ 116,023
130														
131	**Series FPP Scrubber**													
132	Principal	WP 5.1	$ -	$ -	$ -	$ -	$ -	$ -	$ 715,064	$ -	$ -	$ -	$ -	$ 715,064
133	Interest	WP 5.1	-	-	-	-	-	-	1,972,045	-	-	-	-	1,972,045
134			$ -	$ -	$ -	$ -	$ -	$ -	$ 2,687,109	$ -	$ -	$ -	$ -	$ 2,687,109
135														
136	**Commercial Paper in FY 2011**													
137	Principal		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
138	Interest	WP 5.2	-	-	-	-	-	-	61,004	26,061	89,701	39,428	-	216,193
139			$ -	$ -	$ -	$ -	$ -	$ -	$ 61,004	$ 26,061	$ 89,701	$ 39,428	$ -	$ 216,193
140														
141	**Debt Total**													
142	Principal		$ 48,584,914	$ 10,043,702	$ 18,498,902	$ 2,854	$ 844,399	$ 77,974,772	$ 45,014,106	$ 12,326,729	$ 17,454,381	$ 14,921	$ 1,188,231	$ 75,998,369
143	Interest		45,076,758	19,046,046	31,703,243	11,524	3,107,470	98,945,041	43,008,165	18,088,182	32,113,676	50,130	2,893,889	96,154,041
144			**$ 93,661,672**	**$ 29,089,748**	**$ 50,202,145**	**$ 14,379**	**$ 3,951,869**	**$ 176,919,813**	**$ 88,022,271**	**$ 30,414,912**	**$ 49,568,057**	**$ 65,051**	**$ 4,082,120**	**$ 172,152,410**
145														
146														
147														
148	**Priority Lien (1)**													
149	Principal		$ 38,349,824	$ 3,831,259	$ 2,814,730	$ -	$ -	$ 44,995,813	$ 27,172,322	$ 4,324,229	$ 2,581,505	$ -	$ -	$ 34,078,056
150	Interest		28,895,616	7,023,886	4,509,305	-	-	40,428,806	22,553,796	6,181,486	4,462,147	-	-	33,197,429
151			$ 67,245,440	$ 10,855,144	$ 7,324,035	$ -	$ -	$ 85,424,619	$ 49,726,117	$ 10,505,715	$ 7,043,653	$ -	$ -	$ 67,275,485
152														

Work Paper 5 - Debt

Line		Source	FY 2009						FY 2011					
No.	Issue	Reference	Production	Transmission	Distribution	Customer	Non-Electric	Total	Production	Transmission	Distribution	Customer	Non-Electric	Total
A	B	C	O	P	Q	R	S	T	U	V	W	X	Y	Z
153	**Subordinate Lien (2)**													
154	Principal		$ 13,949	$ 365,292	$ 734,123	$ -	$ -	$ 1,113,364	$ 11,485	$ 300,757	$ 604,428	$ -	$ -	$ 916,670
155	Interest		67,359	1,763,942	3,544,970	-	-	5,376,271	66,162	1,732,615	3,482,012	-	-	5,280,789
156			$ 81,308	$ 2,129,234	$ 4,279,093	$ -	$ -	$ 6,489,635	$ 77,647	$ 2,033,372	$ 4,086,440	$ -	$ -	$ 6,197,459
157														
158	**Separate Lien (3)**													
159	Principal		$ 10,215,106	$ 5,763,513	$ 14,880,130	$ -	$ 813,750	$ 31,672,500	$ 17,798,755	$ 7,685,536	$ 14,244,523	$ -	$ 1,150,000	$ 40,878,814
160	Interest		16,089,420	10,246,339	23,631,008	-	3,029,207	52,995,974	20,304,578	10,140,851	24,066,270	-	2,816,097	57,327,796
161			$ 26,304,527	$ 16,009,852	$ 38,511,138	$ -	$ 3,842,957	$ 84,668,474	$ 38,103,333	$ 17,826,387	$ 38,310,793	$ -	$ 3,966,097	$ 98,206,610
162														
163	**GO/CO**													
164	Principal		$ 6,034	$ 83,638	$ 69,919	$ 2,854	$ -	$ 162,446	$ 31,544	$ 16,207	$ 23,925	$ 14,921	$ -	$ 86,598
165	Interest		24,363	11,879	17,960	11,524	-	65,727	22,625	7,169	13,546	10,702	-	54,042
166			$ 30,397	$ 95,517	$ 87,879	$ 14,379	$ -	$ 228,173	$ 54,169	$ 23,376	$ 37,471	$ 25,623	$ -	$ 140,639
167														
168	**Capital Lease**													
169	Principal		$ -	$ -	$ -	$ -	$ 30,649	$ 30,649	$ -	$ -	$ -	$ -	$ 38,231	$ 38,231
170	Interest		-	-	-	-	78,263	78,263	-	-	-	-	77,792	77,792
171			$ -	$ -	$ -	$ -	$ 108,912	$ 108,912	$ -	$ -	$ -	$ -	$ 116,023	$ 116,023
172														
173	**Commercial Paper**													
174	Principal		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
175	Interest		-	-	-	-	-	-	61,004	26,061	89,701	39,428	-	216,193
176			$ -	$ -	$ -	$ -	$ -	$ -	$ 61,004	$ 26,061	$ 89,701	$ 39,428	$ -	$ 216,193

Work Paper 5.1 - Debt

Purpose: Estimate Debt Service for a Permanent Debt Issue Associated with the FPP Scrubbers Put in Service in FY 2011

Line No.		Source Reference		Test Year
A		B		C
1	Scrubber related Commercial Paper Outstanding	WP 5.2	$	18,000,000
2				
3	Remaining Capital Spending on Scrubbers	WP 14	$	26,000,000
4				
5	**Total Scrubber CIP to be Included in Permanent Debt**		**$**	**44,000,000**
6				
7				
8	Debt Assumptions			
9	Term (years)			30
10	Rate			4.50%
11	Level, Semi-Annual Payments			
12				
13	Test Year Debt Service [1]			
14	Principal		$	715,064
15	Interest			1,972,045
16			**$**	**2,687,109**
17				
18	Notes:			
19	[1] This hypothetical debt issue contains all FPP scrubber capital costs not already captured in			
20	outstanding permanent debt			

Work Paper 5.2 - Debt

Purpose: Estimate Test Year Interest on Commercial Paper

Line No.		Source Reference	Test Year		
A		B	C		
1	Average Annual Capital Spending	WP 14	$ 222,182,023		
2	Average Annual Capital Spending to be Cash Funded	WP 14	111,091,011		
3	Average Annual Capital Spending to be Debt Funded		$ 111,091,011		
4					
5	Average Capital Spending Related to FPP Scrubbers [1]	WP 14	$ 39,159,914		
6					
7	Remaining Capital Spending to be Included in Commercial Paper		**$ 71,931,098**		
8					
9	Average Addition to Commercial Paper Balance per Month		$ 5,994,258		
10					
11					
12	Outstanding Commercial Paper (as of 10/31/2010) [3]	SD-13	$ 51,615,000		
13	Portion Associated with FPP Scrubbers [2]	SD-13	18,000,000		
14	Net Amount to be Included in Commercial Paper Balance		**$ 33,615,000**		
15					
16					
17	**Commercial Paper Balance by Month (Estimated)**		**Beginning**	**Ending**	**Average**
18	1 October 2010		$ 27,620,742	$ 33,615,000	$ 30,617,871
19	2 November 2010		33,615,000	39,609,258	36,612,129
20	3 December 2010		39,609,258	45,603,516	42,606,387
21	4 January 2011		45,603,516	51,597,774	48,600,645
22	5 February 2011		51,597,774	57,592,033	54,594,903
23	6 March 2011		57,592,033	63,586,291	60,589,162
24	7 April 2011		63,586,291	69,580,549	66,583,420
25	8 May 2011		69,580,549	75,574,807	72,577,678
26	9 June 2011		75,574,807	81,569,065	78,571,936
27	10 July 2011		81,569,065	87,563,323	84,566,194
28	11 August 2011		87,563,323	93,557,581	90,560,452
29	12 September 2011		93,557,581	99,551,839	96,554,710
30					
31	Interest Rate on Commercial Paper [4]	SD-33	0.34%		
32					
33	**Interest Expense on in Test Year (based on Average Balance)**		**$ 216,193**		
34					
35	Notes:				
36	[1] Scrubber spending is assumed to be captured within a permanent debt issue, as shown on WP 5.1				
37	[2] This amount associated with FPP Scrubbers will be included in an assumed permanent debt issue as shown on WP 5.1				
38	[3] Commercial paper is typically rolled to permanent debt at around $150 million				
39	[4] Based on commercial paper rate in October 2010				

Work Paper 5.3 - Debt

Purpose: Sub-Functionalize the Debt Service Associated with the Production Function

Line No.	Issue	Source Reference	Production Test Year	Allocation Reference	Facility	Net Plant In Service Intermediate	Net Plant In Service Peak	Net Plant In Service Total	Holly Intermediate Gas	FPP Base Load Coal	STP Base Load Nuclear	SHEC Peak Gas	SHEC Intermediate Gas	Energy Efficiency	Other
A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**GO Series 1999**				**Decker**	$ 43,601,082	$ 25,236,386	$ 68,837,468							
2	Principal	WP 5	$ -			**63.3%**	**36.7%**	**100.0%**							
3	Interest	WP 5	-			Source Reference: WP 26 - Prod Plant									
4			$ -	WP 26					0.0%	25.3%	42.8%	12.1%	13.4%	0.0%	0.0%
5															
6	**GO Series 2003**														
7	Principal	WP 5	$ -												
8	Interest	WP 5	-												
9			$ -	WP 26					0.0%	25.3%	42.8%	12.1%	13.4%	0.0%	0.0%
10															
11	**GO Series 2005**														
12	Principal	WP 5	$ 27,115												
13	Interest	WP 5	20,678												
14			$ 47,793	WP 26					0.0%	25.3%	42.8%	12.1%	13.4%	0.0%	0.0%
15															
16	**GO Series 2008**														
17	Principal	WP 5	$ 4,429												
18	Interest	WP 5	1,947												
19			$ 6,376	WP 26					0.0%	25.3%	42.8%	12.1%	13.4%	0.0%	0.0%
20															
21	**Revenue Series 1990B (CAB)**														
22	Principal	WP 5	$ -												
23	Interest	WP 5	-												
24			$ -	SD-12					0.0%	0.0%	58.4%	0.0%	0.0%	0.0%	4.9%
25															
26	**Revenue Series 1992**														
27	Principal	WP 5	$ 1,645,732												
28	Interest	WP 5	4,394,357												
29			$ 6,040,090	SD-12					0.0%	0.0%	86.2%	0.0%	0.0%	0.0%	13.8%
30															
31	**Revenue Series 1992AR CAB**														
32	Principal	WP 5	$ 5,587,923												
33	Interest	WP 5	14,499,380												
34			$ 20,087,304	SD-12					0.0%	0.0%	82.5%	0.0%	0.0%	0.0%	17.5%
35															
36	**Revenue Series 1993**														
37	Principal	WP 5	$ 4,617,030												
38	Interest	WP 5	791,057												
39			$ 5,408,087	SD-12					0.0%	2.1%	80.8%	0.0%	0.0%	0.0%	14.1%
40															
41	**Revenue Series 1993 CAB**														
42	Principal	WP 5	$ 82,819												
43	Interest	WP 5	165,893												
44			$ 248,712	SD-12					0.0%	2.1%	80.8%	0.0%	0.0%	0.0%	14.1%
45															
46	**Revenue Series 1993A CAB**														
47	Principal	WP 5	$ 257,556												
48	Interest	WP 5	455,915												
49			$ 713,470	SD-12					0.0%	13.8%	80.7%	0.0%	0.0%	0.0%	5.0%
50															

Work Paper 5.3 - Debt

Purpose: Sub-Functionalize the Debt Service Associated with the Production Function

Line No.	Issue	Source Reference	Production Test Year	Allocation Reference	Facility	Net Plant In Service Intermediate	Net Plant In Service Peak	Net Plant In Service Total	Holly Intermediate Gas	FPP Base Load Coal	STP Base Load Nuclear	SHEC Peak Gas	SHEC Intermediate Gas	Energy Efficiency	Other
A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
51	**Revenue Series 1996A**														
52	Principal	WP 5	$ -												
53	Interest	WP 5	-												
54			$ -	SD-12					0.0%	0.0%	95.4%	0.0%	0.0%	0.0%	2.1%
55															
56	**Revenue Series 1998 PRIOR LIEN**														
57	Principal	WP 5	$ 14,981,262												
58	Interest	WP 5	2,247,193												
59			$ 17,228,455	SD-12					0.0%	19.0%	80.1%	0.0%	0.0%	0.0%	0.7%
60															
61	**Revenue Series 1998 SUBORDINATE LIEN**														
62	Principal	WP 5	$ 11,485												
63	Interest	WP 5	66,162												
64			$ 77,647	SD-12					0.0%	13.6%	81.6%	0.0%	0.0%	0.0%	3.8%
65															
66	**Revenue Series 2001**														
67	Principal	WP 5	$ -												
68	Interest	WP 5	-												
69			$ -						0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
70															
71	**Revenue Series 2002**														
72	Principal	WP 5	$ 1,993,313												
73	Interest	WP 5	1,013,679												
74			$ 3,006,992	SD-12					0.0%	0.0%	92.2%	0.0%	0.0%	0.0%	7.8%
75															
76	**Revenue Series 2002A**														
77	Principal	WP 5	$ 111,922												
78	Interest	WP 5	2,965,014												
79			$ 3,076,936	SD-12					0.0%	0.0%	83.7%	0.0%	0.0%	0.0%	16.3%
80															
81	**Revenue Series 2003**														
82	Principal	WP 5	$ -												
83	Interest	WP 5	-												
84			$ -						0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
85															
86	**Revenue Series 2006**														
87	Principal	WP 5	$ -												
88	Interest	WP 5	-												
89			$ -						0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
90															
91	**Revenue Series 2006A**														
92	Principal	WP 5	$ 6,380,752												
93	Interest	WP 5	2,720,064												
94			$ 9,100,816	SD-12					0.0%	0.0%	95.4%	0.0%	0.0%	0.0%	2.1%
95															
96	**Revenue Series 2007**														
97	Principal	WP 5	$ 8,529,785												
98	Interest	WP 5	5,134,741												
99			$ 13,664,527	SD-12					0.0%	1.4%	93.0%	0.0%	0.0%	0.0%	4.3%
100															

Work Paper 5.3 - Debt

Purpose: Sub-Functionalize the Debt Service Associated with the Production Function

Line No.	Issue	Source Reference	Production Test Year	Allocation Reference	Facility	Net Plant In Service: Intermediate	Net Plant In Service: Peak	Net Plant In Service: Total	Holly Intermediate Gas	FPP Base Load Coal	STP Base Load Nuclear	SHEC Peak Gas	SHEC Intermediate Gas	Energy Efficiency	Other
A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
101	**Revenue Series 2008**														
102	Principal	WP 5	$ -												
103	Interest	WP 5	-												
104			$ -						0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
105															
106	**Revenue Series 2008A**														
107	Principal	WP 5	$ 67,918												
108	Interest	WP 5	3,129,407												
109			$ 3,197,325	SD-12					0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%
110															
111	**Series 2010A CP refunding**														
112	Principal	WP 5	$ -												
113	Interest	WP 5	1,378,392												
114			$ 1,378,392	SD-12					0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%
115															
116	**Series 2010A Tax Exempt refunding**														
117	Principal	WP 5	$ -												
118	Interest	WP 5	158,487												
119			$ 158,487	SD-12					0.0%	2.1%	80.8%	0.0%	0.0%	0.0%	14.1%
120															
121	**Series 2010B BAB CP refunding**														
122	Principal	WP 5	$ -												
123	Interest	WP 5	1,832,750												
124			$ 1,832,750	SD-12					0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%
125															
126	**Capital Lease**														
127	Principal	WP 5	$ -												
128	Interest	WP 5	-												
129			$ -						0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
130															
131	**Series FPP Scrubber**														
132	Principal	WP 5	$ 715,064												
133	Interest	WP 5	1,972,045												
134			$ 2,687,109	SD-12					0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%
135															
136	**Commercial Paper in FY 2011**														
137	Principal	WP 5	$ -												
138	Interest	WP 5	61,004												
139			$ 61,004	WP 26					0.0%	25.3%	42.8%	12.1%	13.4%	0.0%	0.0%
140															
141	**Debt Total**														
142	Principal		$ 45,014,106												
143	Interest		43,008,165												
144			**$ 88,022,271**												

Work Paper 5.3 - Debt

Line No.	Issue	Source Reference	Decker Intermediate Gas	Decker Peak Gas	Total	Holly Intermediate Gas	FPP Base Load Coal	STP Base Load Nuclear	SHEC Peak Gas	SHEC Intermediate Gas	Energy Efficiency	Other	Decker Intermediate Gas	Decker Peak Gas	Total
A	B	C	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC
1	**GO Series 1999**														
2	Principal	WP 5													
3	Interest	WP 5													
4			4.0%	2.3%	100.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5															
6	**GO Series 2003**														
7	Principal	WP 5													
8	Interest	WP 5													
9			4.0%	2.3%	100.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10															
11	**GO Series 2005**														
12	Principal	WP 5													
13	Interest	WP 5													
14			4.0%	2.3%	100.0%	$ -	$ 12,105	$ 20,476	$ 5,767	$ 6,408	$ -	$ -	$ 1,923	$ 1,113	$ 47,793
15															
16	**GO Series 2008**														
17	Principal	WP 5													
18	Interest	WP 5													
19			4.0%	2.3%	100.0%	$ -	$ 1,615	$ 2,732	$ 769	$ 855	$ -	$ -	$ 257	$ 148	$ 6,376
20															
21	**Revenue Series 1990B (CAB)**														
22	Principal	WP 5													
23	Interest	WP 5													
24			23.2%	13.4%	100.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25															
26	**Revenue Series 1992**														
27	Principal	WP 5													
28	Interest	WP 5													
29			0.0%	0.0%	100.0%	$ -	$ -	$ 5,209,325	$ -	$ -	$ -	$ 830,765	$ -	$ -	$ 6,040,090
30															
31	**Revenue Series 1992AR CAB**														
32	Principal	WP 5													
33	Interest	WP 5													
34			0.0%	0.0%	100.0%	$ -	$ -	$ 16,569,826	$ -	$ -	$ -	$ 3,517,478	$ -	$ -	$ 20,087,304
35															
36	**Revenue Series 1993**														
37	Principal	WP 5													
38	Interest	WP 5													
39			1.9%	1.1%	100.0%	$ -	$ 112,958	$ 4,371,094	$ -	$ -	$ -	$ 762,578	$ 102,265	$ 59,191	$ 5,408,087
40															
41	**Revenue Series 1993 CAB**														
42	Principal	WP 5													
43	Interest	WP 5													
44			1.9%	1.1%	100.0%	$ -	$ 5,195	$ 201,022	$ -	$ -	$ -	$ 35,070	$ 4,703	$ 2,722	$ 248,712
45															
46	**Revenue Series 1993A CAB**														
47	Principal	WP 5													
48	Interest	WP 5													
49			0.3%	0.2%	100.0%	$ -	$ 98,149	$ 575,874	$ -	$ -	$ -	$ 35,531	$ 2,481	$ 1,436	$ 713,470
50															

Work Paper 5.3 - Debt

Line No.	Issue	Source Reference	Decker Intermediate Gas	Decker Peak Gas	Total	Holly Intermediate Gas	FPP Base Load Coal	STP Base Load Nuclear	SHEC Peak Gas	SHEC Intermediate Gas	Energy Efficiency	Other	Decker Intermediate Gas	Decker Peak Gas	Total
A	B	C	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC
51	**Revenue Series 1996A**														
52	Principal	WP 5													
53	Interest	WP 5													
54			1.6%	0.9%	100.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55															
56	**Revenue Series 1998 PRIOR LIEN**														
57	Principal	WP 5													
58	Interest	WP 5													
59			0.1%	0.1%	100.0%	$ -	$ 3,272,299	$ 13,808,114	$ -	$ -	$ -	$ 122,091	$ 16,437	$ 9,514	$ 17,228,455
60															
61	**Revenue Series 1998 SUBORDINATE**														
62	Principal	WP 5													
63	Interest	WP 5													
64			0.7%	0.4%	100.0%	$ -	$ 10,523	$ 63,322	$ -	$ -	$ -	$ 2,960	$ 534	$ 309	$ 77,647
65															
66	**Revenue Series 2001**														
67	Principal	WP 5													
68	Interest	WP 5													
69			0.0%	0.0%	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70															
71	**Revenue Series 2002**														
72	Principal	WP 5													
73	Interest	WP 5													
74			0.0%	0.0%	100.0%	$ -	$ -	$ 2,771,605	$ -	$ -	$ -	$ 235,387	$ -	$ -	$ 3,006,992
75															
76	**Revenue Series 2002A**														
77	Principal	WP 5													
78	Interest	WP 5													
79			0.0%	0.0%	100.0%	$ -	$ -	$ 2,575,631	$ -	$ -	$ -	$ 501,304	$ -	$ -	$ 3,076,936
80															
81	**Revenue Series 2003**														
82	Principal	WP 5													
83	Interest	WP 5													
84			0.0%	0.0%	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85															
86	**Revenue Series 2006**														
87	Principal	WP 5													
88	Interest	WP 5													
89			0.0%	0.0%	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90															
91	**Revenue Series 2006A**														
92	Principal	WP 5													
93	Interest	WP 5													
94			1.6%	0.9%	100.0%	$ -	$ -	$ 8,683,777	$ -	$ -	$ -	$ 194,309	$ 141,075	$ 81,655	$ 9,100,816
95															
96	**Revenue Series 2007**														
97	Principal	WP 5													
98	Interest	WP 5													
99			0.8%	0.5%	100.0%	$ -	$ 186,289	$ 12,710,079	$ -	$ -	$ -	$ 589,835	$ 112,949	$ 65,375	$ 13,664,527
100															

Work Paper 5.3 - Debt

Line No.	Issue	Source Reference	Decker Intermediate Gas	Decker Peak Gas	Total	Holly Intermediate Gas	FPP Base Load Coal	STP Base Load Nuclear	SHEC Peak Gas	SHEC Intermediate Gas	Energy Efficiency	Other	Decker Intermediate Gas	Decker Peak Gas	Total
A	B	C	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC
101	**Revenue Series 2008**														
102	Principal	WP 5													
103	Interest	WP 5													
104			0.0%	0.0%	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
105															
106	**Revenue Series 2008A**														
107	Principal	WP 5													
108	Interest	WP 5													
109			0.0%	0.0%	100.0%	$ -	$ 3,197,325	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,197,325
110															
111	**Series 2010A CP refunding**														
112	Principal	WP 5													
113	Interest	WP 5													
114			0.0%	0.0%	100.0%	$ -	$ 1,378,392	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,378,392
115															
116	**Series 2010A Tax Exempt refunding**														
117	Principal	WP 5													
118	Interest	WP 5													
119			1.9%	1.1%	100.0%	$ -	$ 3,310	$ 128,097	$ -	$ -	$ -	$ 22,348	$ 2,997	$ 1,735	$ 158,487
120															
121	**Series 2010B BAB CP refunding**														
122	Principal	WP 5													
123	Interest	WP 5													
124			0.0%	0.0%	100.0%	$ -	$ 1,832,750	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,832,750
125															
126	**Capital Lease**														
127	Principal	WP 5													
128	Interest	WP 5													
129			0.0%	0.0%	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
130															
131	**Series FPP Scrubber**														
132	Principal	WP 5													
133	Interest	WP 5													
134			0.0%	0.0%	100.0%	$ -	$ 2,687,109	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,687,109
135															
136	**Commercial Paper in FY 2011**														
137	Principal	WP 5													
138	Interest	WP 5													
139			4.0%	2.3%	100.0%	$ -	$ 15,452	$ 26,137	$ 7,362	$ 8,179	$ -	$ -	$ 2,454	$ 1,421	$ 61,004
140															
141	**Debt Total**														
142	Principal														
143	Interest														
144						**$ -**	**$ 12,813,471**	**$ 67,717,112**	**$ 13,898**	**$ 15,443**	**$ -**	**$ 6,849,656**	**$ 388,074**	**$ 224,618**	**$ 88,022,271**

Work Paper 6 - G&A

Purpose: Identify Direct Allocations of General and Administrative (G&A) Expenses to the Production Function and Functionalize the Remaining G&A on Selected Allocators

Line No.		FERC Account	Test Year Source Reference	Adjusted Test Year	Direct Allocation to Production: Source Reference	2300 Joint Project	2411 FPP	2415 STP	Boiler Insurance	Other	Total
A		B	C	D	E	F	G	H	I	J	K
1	**General and Administrative Expenses**										
2	Administrative and General Salaries	920	Functional Unbundling	$ 30,891,148	SD-14	$ -	$ -	$ 1,913,089	$ -	$ -	$ 1,913,089
3	Office Supplies and Expenses	921	Functional Unbundling	20,495,909	SD-14	3,988	-	479,503	-	-	483,491
4	Administrative Expense Transferred	922	Functional Unbundling	964,581	SD-14	-	(125,415)	(163,292)	-	-	(288,707)
5	Outside Services Employed	923	Functional Unbundling	9,975,100	SD-14	-	-	1,513,819	-	-	1,513,819
6	Property Insurance	924	Functional Unbundling	2,893,058	SD-14	-	233,550	425,511	41,923	-	700,984
7	Injuries and Damages	925	Functional Unbundling	2,963,720	SD-14	-	125,803	384,328	-	-	510,131
8	Employee Pension and Benefits	926	Functional Unbundling	10,381,582	SD-14 & WP 33	-	3,249,249	6,541,200	-	-	9,790,449
9	Regulatory Commission Expense	928	Functional Unbundling	1,292,907	SD-14	-	-	-	-	-	-
10	General Expenses	930	Functional Unbundling	21,470,867	SD-14	-	1,070,546	749,995	-	-	1,820,541
11	Rents	931	Functional Unbundling	2,124,920	SD-14	-	-	-	-	-	-
12	Maintenance of General Plant	935	Functional Unbundling	947,017	SD-14	-	-	874,593	-	-	874,593
13				$ 104,400,808		$ 3,988	$ 4,553,733	$ 12,718,746	$ 41,923	$ -	$ 17,318,390

Work Paper 6 - G&A

Line No.		FERC Account	Net After Direct Allocation	Net Allocation Basis	Allocation of Net Production	Transmission	Distribution	Customer	Total
A		B	L	M	N	O	P	Q	R
1	**General and Administrative Expenses**								
2	Administrative and General Salaries	920	$ 28,978,060	PAYXAG	$ 6,936,655	$ 2,761,525	$ 8,519,743	$ 10,760,137	$ 28,978,060
3	Office Supplies and Expenses	921	20,012,417	PAYXAG	4,790,494	1,907,125	5,883,784	7,431,014	20,012,417
4	Administrative Expense Transferred	922	1,253,287	PAYXAG	300,007	119,435	368,475	465,371	1,253,287
5	Outside Services Employed	923	8,461,281	TOMXFP	4,240,190	1,904,049	1,199,951	1,117,091	8,461,281
6	Property Insurance	924	2,192,074	INSUR	1,557,031	95,671	532,369	7,004	2,192,074
7	Injuries and Damages	925	2,453,589	PAYXAG	587,331	233,820	721,372	911,067	2,453,589
8	Employee Pension and Benefits	926	591,133	PAYXAG	141,503	56,333	173,797	219,500	591,133
9	Regulatory Commission Expense	928	1,292,907	PLTXGNL-N	670,167	158,459	464,281	-	1,292,907
10	General Expenses	930	19,650,325	PAYXAG	4,703,818	1,872,619	5,777,327	7,296,562	19,650,325
11	Rents	931	2,124,920	PAYXAGT	562,234	-	690,548	872,138	2,124,920
12	Maintenance of General Plant	935	72,424	GNLPLT-N	20,566	8,006	22,537	21,316	72,424
13			$ 87,082,418		$ 24,509,995	$ 9,117,040	$ 24,354,184	$ 29,101,199	$ 87,082,418

Work Paper 6 - G&A

Line No.		FERC Account	Allocation of Total Production	Transmission	Distribution	Customer	Total
A		B	S	T	U	V	W
1	**General and Administrative Expenses**						
2	Administrative and General Salaries	920	$ 8,849,743	$ 2,761,525	$ 8,519,743	$ 10,760,137	$ 30,891,148
3	Office Supplies and Expenses	921	5,273,986	1,907,125	5,883,784	7,431,014	20,495,909
4	Administrative Expense Transferred	922	11,300	119,435	368,475	465,371	964,581
5	Outside Services Employed	923	5,754,009	1,904,049	1,199,951	1,117,091	9,975,100
6	Property Insurance	924	2,258,015	95,671	532,369	7,004	2,893,058
7	Injuries and Damages	925	1,097,461	233,820	721,372	911,067	2,963,720
8	Employee Pension and Benefits	926	9,931,952	56,333	173,797	219,500	10,381,582
9	Regulatory Commission Expense	928	670,167	158,459	464,281	-	1,292,907
10	General Expenses	930	6,524,359	1,872,619	5,777,327	7,296,562	21,470,867
11	Rents	931	562,234	-	690,548	872,138	2,124,920
12	Maintenance of General Plant	935	895,159	8,006	22,537	21,316	947,017
13			$ 41,828,385	$ 9,117,040	$ 24,354,184	$ 29,101,199	$ 104,400,808

Work Paper 7 - City Services

Purpose: Identify Adjustment to Costs Associated with City of Austin Programs and Transfers for the Test Year

Line No.		FERC Account	Source Reference	FY 2009 Actual	FY 2010 Actual	Increase / (Decrease)	Additional Adjustments Source Reference	Revised
A		B	C	D	E	F	G	H
1	**Transfers and Program Funding**							
2	Transfer to DSMBR for Service Provider Contracts	923	SD-15	$ 167,000	$ 167,000	$ -		$ 167,000
3	311 Call Center	417	WP 7.1	5,958,622	7,635,167	1,676,545	WP 7.1	7,635,167
4	311 Call Center	921	WP 7.1	(2,100,000)	(2,000,000)	100,000	WP 7.1	(2,000,000)
5	General Fund Transfer		SD-15	95,000,000	101,000,000	6,000,000	SD-15	101,000,000
6	CC & B CIP Allocation	905		-	-	-	SD-42	-
7				$ 99,025,622	$ 106,802,167	$ 7,776,545		$ 106,802,167
8								
9	**Economic Development (EGRSO)**							
10	EGRSO - Eco Devel Cultural Arts	911	SD-15	$ 1,156,145	$ 1,401,804	$ 245,660	SD-15	$ 1,401,804
11	EGRSO - Legal Contracts City-wide	911	SD-15	500,000	304,000	(196,000)	SD-15	304,000
12	EGRSO - Economic Development	911	SD-15	6,093,421	6,197,198	103,777	SD-15	6,197,198
13				$ 7,749,565	$ 7,903,002	$ 153,437		$ 7,903,002
14								
15	**City Support, Purchases & Payments for Services**							
16	Records Retention	921	SD-15	$ 31,674	$ 30,484	$ (1,190)		$ 30,484
17	APD - Homeland Security Services at power plants	923	SD-15	910,798	903,764	(7,034)	SD-15	903,764
18	Other Purchases - Legal Dept Continuing Education for Law Dept Attorneys	921	SD-15	12,000	12,000	-		12,000
19	Ecapris and eCOMBS Support	921	SD-15	312,448	318,660	6,212		318,660
20	Other Purchases - Fixed Assets FTE/eCOMBS Support Back charge	921	SD-15	129,476	-	(129,476)		-
21	Other - Drug/Alcohol Testing	921	SD-15	4,743	3,345	(1,398)		3,345
22	Other - FLEXTRA Administration	921	SD-15	30,054	-	(30,054)		-
23	Purchasing Back charge for staff dedicated strictly to AE needs	921	SD-15	1,407,968	1,252,333	(155,635)	SD-15	1,252,333
24	Information System Department	921	SD-15	6,053,349	5,212,512	(840,837)	SD-15	5,212,512
25	Other Purchases - Lobbyist Paid to Outside Organization	921	SD-15	97,256	107,250	9,994		107,250
26	Library - Cards for outside City Electric customers	930	SD-15	-	-	-		-
27	Other City Support - Clean Air Program - City Employee Bus Pass Program	921	SD-15	110,000	-	(110,000)		-
28	Consolidated operations Additional GIS services for AE - CTM	930	SD-15	-	-	-		-
29	Consolidated operations of Organizational Development and Learning Resource Center - HRD	930	SD-15	1,309,660	-	(1,309,660)		-
30	Other Purchases - Voice of the Citizen Survey	930	SD-15	41,520	-	(41,520)		-
31	Other Purchases - Building Services	451	SD-15	21,544	31,139	9,595	SD-15	31,139
32	Other Purchases - Green Building Program Energy Inspections	908	SD-15	170,520	139,760	(30,760)		139,760
33	Reorganization - Clean Air Program - Transfer Air Quality from TPSD 4 FTEs to AE	902	SD-15	340,475	244,151	(96,324)		244,151
34	Other City Support - One Stop Support	920	SD-15	213,902	182,334	(31,568)		182,334
35	Office of City Auditor (OCA) - staff working directly on AE related projects	923	SD-15	200,000	200,000	-		200,000
36	Other Purchases - APD Current Diversion Investigations	921	SD-15	81,844	133,276	51,432		133,276
37	Street Lighting - Public Works	921	SD-15	7,423,182	5,203,724	(2,219,458)	SD-15	5,203,724
38	Administrative Support	930	SD-15	13,876,374	14,523,426	647,052	SD-15	14,523,426
39	Workers' Compensation	925	SD-15	534,000	1,563,349	1,029,349	SD-15	1,563,349
40	Liability Reserve	925	SD-15	594,000	594,000	-	SD-15	594,000
41				$ 33,906,787	$ 30,655,506	$ (3,251,281)		$ 30,655,506
42								
43				**$ 140,681,974**	**$ 145,360,675**	**$ 4,678,701**		**$ 145,360,675**

Work Paper 7 - City Services

Purpose: Identify Adjustment to Costs Associated with City of Austin Programs and Transfers for the Test Year

Line No.		Additional Adjustments	Test Year	Total Adjustment
A		I	J	K
1	**Transfers and Program Funding**			
2	Transfer to DSMBR for Service Provider Contracts		$ 167,000	$ -
3	311 Call Center	(5,556,081)	2,079,086	(3,879,536)
4	311 Call Center	2,000,000	-	2,100,000
5	General Fund Transfer	2,000,000	103,000,000	8,000,000
6	CC & B CIP Allocation	(1,339,036)	(1,339,036)	(1,339,036)
7			$ 103,907,050	$ 4,881,428
8				
9	**Economic Development (EGRSO)**			
10	EGRSO - Eco Devel Cultural Arts	$ (7,809)	$ 1,393,995	$ 237,850
11	EGRSO - Legal Contracts City-wide	193,724	497,724	(2,276)
12	EGRSO - Economic Development	1,390,590	7,587,788	1,494,367
13			$ 9,479,507	$ 1,729,942
14				
15	**City Support, Purchases & Payments for Services**			
16	Records Retention		$ 30,484	$ (1,190)
17	APD - Homeland Security Services at power plants	(18,075)	885,689	(25,109)
18	Other Purchases - Legal Dept Continuing Education for Law Dept Attorneys		12,000	-
19	Ecapris and eCOMBS Support		318,660	6,212
20	Other Purchases - Fixed Assets FTE/eCOMBS Support Back charge		-	(129,476)
21	Other - Drug/Alcohol Testing		3,345	(1,398)
22	Other - FLEXTRA Administration		-	(30,054)
23	Purchasing Back charge for staff dedicated strictly to AE needs	66,567	1,318,899	(89,069)
24	Information System Department	712,291	5,924,803	(128,546)
25	Other Purchases - Lobbyist Paid to Outside Organization		107,250	9,994
26	Library - Cards for outside City Electric customers		-	-
27	Other City Support - Clean Air Program - City Employee Bus Pass Program		-	(110,000)
28	Consolidated operations Additional GIS services for AE - CTM		-	-
29	Consolidated operations of Organizational Development and Learning Resource Center - H		-	(1,309,660)
30	Other Purchases - Voice of the Citizen Survey		-	(41,520)
31	Other Purchases - Building Services	(1,744)	29,394	7,850
32	Other Purchases - Green Building Program Energy Inspections		139,760	(30,760)
33	Reorganization - Clean Air Program - Transfer Air Quality from TPSD 4 FTEs to AE		244,151	(96,324)
34	Other City Support - One Stop Support		182,334	(31,568)
35	Office of City Auditor (OCA) - staff working directly on AE related projects		200,000	-
36	Other Purchases - APD Current Diversion Investigations		133,276	51,432
37	Street Lighting - Public Works	(5,203,724)	-	(7,423,182)
38	Administrative Support	666,133	15,189,559	1,313,185
39	Workers' Compensation	102,640	1,665,989	1,131,989
40	Liability Reserve	(44,000)	550,000	(44,000)
41			$ 26,935,594	$ (6,971,193)
42				
43			**$ 140,322,151**	**$ (359,823)**

Work Paper 7.1 - City Services

Purpose: Adjust Payments Related to the 311 Call Center to Isolate the Proportion Attributable to Austin Energy

Line No.		FERC Account	FY 2009 Source Reference	FY 2010 & FY 2011 Source Reference	FY 2009 Actual	FY 2010 Actual	FY 2011 Budget	% of Total	Test Year
A		B	C	D	E	F	G	H	I
1	**311 Call Center**								
2	Austin Energy		SD-3	SD-16	$ 3,858,622	$ 5,635,167	$ 2,079,086	25.5%	$ 2,079,086
3	General Fund		SD-3	SD-16	2,100,000	1,000,000	1,000,000	12.3%	-
4	Austin water Utility		SD-3	SD-16	-	1,000,000	1,000,000	12.3%	-
5	Solid Waste/Code Compliance		SD-3	SD-16	-	-	4,079,087	50.0%	-
6					$ 5,958,622	$ 7,635,167	$ 8,158,173	100.0%	$ 2,079,086
7									
8	**Summary in FERC**								
9	Gross Expense	417	SD-3	SD-16	$ 5,958,622	$ 7,635,167	$ 8,158,173		$ 2,079,086
10	Contra-Expense (transfers)	921	SD-3	SD-16	(2,100,000)	(2,000,000)	(6,079,087)		-
11	Net 311 Call Center (cost to AE)				$ 3,858,622	$ 5,635,167	$ 2,079,086		$ 2,079,086
12									

Austin Energy
Electric Cost of Service

Work Paper 8 - Holly Inventory

Purpose: Adjustment to Remove FY 2009 Write-Off of Holly Inventory from Test Year

Line No.		FERC Account	Source Reference	FY 2009 Actual	Test Year	Total Adjustment
A		B	C	D	E	F
1	Holly Inventory Write-Off					
2		921	SD-63	$ 1,756,428	$ -	$ (1,756,428)

Work Paper 9 - Franchise Fees

Purpose: Estimate Franchise Fees Payable by Austin Energy to Other Cities Where AE Provides Electric Servic

Line No.		FY 2009 Source Reference	FY 2010 & Rate Source Reference	FY 2009 Actual	FY 2010 Actual	COS Rate Increase Source Reference	Overall System Cost of Service Rate Increase	Test Year Estimated [1]
A		B	C	D	E	F	G	H
1	**City of Bee Caves**							
2	Revenues	SD-19	SD-20	$ 8,489,799	$ 9,088,216	Functional Unbundling	13.1%	$ 9,604,883
3	Rate		SD-20	0.00%	0.00%			3.00%
4	Franchise Fee			$ -	$ -			$ 288,146
5								
6	**City of Cedar Park**							
7	Revenues	SD-19	SD-20	$ 14,056	$ 13,960	Functional Unbundling	13.1%	$ 15,902
8	Rate		SD-20	0.00%	0.00%			3.00%
9	Franchise Fee			$ -	$ -			$ 477
10								
11	**Village of Lakeway**							
12	Revenues	SD-19	SD-20	$ 8,365,227	$ 8,855,245	Functional Unbundling	13.1%	$ 9,463,949
13	Rate		SD-20	0.00%	0.00%			3.00%
14	Franchise Fee			$ -	$ -			$ 283,918
15								
16	**City of Mustang Ridge**							
17	Revenues	SD-19	SD-20	$ 713	$ 799	Functional Unbundling	13.1%	$ 806
18	Rate		SD-20	0.00%	0.00%			3.00%
19	Franchise Fee			$ -	$ -			$ 24
20								
21	**City of Pflugerville**							
22	Revenues	SD-19	SD-20	$ 673,123	$ 635,426	Functional Unbundling	13.1%	$ 761,533
23	Rate		SD-20	0.00%	0.00%			3.00%
24	Franchise Fee			$ -	$ -			$ 22,846
25								
26	**City of Rollingwood**							
27	Revenues	SD-19	SD-20	$ 2,637,117	$ 2,653,939	Functional Unbundling	13.1%	$ 2,983,487
28	Rate		SD-20	0.00%	0.00%			3.00%
29	Franchise Fee			$ -	$ -			$ 89,505
30								
31	**City of Sunset Valley**							
32	Revenues	SD-19	SD-20	$ 3,003,470	$ 3,033,333	Functional Unbundling	13.1%	$ 3,397,958
33	Rate		SD-20	0.00%	0.00%			3.00%
34	Franchise Fee			$ -	$ -			$ 101,939
35								
36	**City of West Lake Hills**							
37	Revenues	SD-19	SD-20	$ 8,233,566	$ 8,359,684	Functional Unbundling	13.1%	$ 9,314,995
38	Rate		SD-20	0.00%	0.00%			3.00%
39	Franchise Fee			$ -	$ -			$ 279,450
40								
41	**Village of the Hills**							
42	Revenues	SD-19	SD-20	$ 1,693,346	$ 1,819,208	Functional Unbundling	13.1%	$ 1,915,756
43	Rate		SD-20	0.00%	0.00%			3.00%
44	Franchise Fee			$ -	$ -			$ 57,473
45								
46	**Total Franchise Fees**			**$ -**	**$ -**			**$ 1,123,778**
47								
48	Notes:							
49	[1] Test Year revenue estimate based on FY 2009 Actual and the overall system cost of service based rate increase (as identified on the Functional Unbundling worksheet)							

Work Paper 10 - Power Factor Adjustment

Purpose: Adjustment to Power Factor Penalty Revenues to All Applicable Customers at 90% (Rather than the 85% in FY 2009)

Line No.		Source Reference	FY 2009 Actual @ 85% PF	FY 2011 Estimated @ 90% PF	Total Adjustment [1]	Percent of Total	Allocation to Customers > 10 KW
A		B	C	D	E	F	G
1							
2	General Service						
3	Secondary Voltage < 10 kW	SD-21	$ -	$ 6,472	$ 6,472	0.28%	**0.00%**
4	Secondary Voltage 10 - 49.9 kW	SD-21	256	441,369	441,113	19.05%	**19.10%**
5	Secondary Voltage ≥ 50 kW	SD-21	11,089	1,619,158	1,608,069	69.45%	**69.64%**
6	Subtotal		$ 11,345	$ 2,066,999	$ 2,055,655		
7							
8	Primary Service						
9	Primary Voltage < 3 MW	SD-21	$ 51,642	$ 311,559	$ 259,918	11.22%	**11.26%**
10	Primary Voltage 3 - 19.9 MW	SD-21	3,056	3,056	-	0.00%	**0.00%**
11	Primary Voltage ≥ 20 MW	SD-21	-	-	-	0.00%	**0.00%**
12	Subtotal		$ 54,698	$ 314,616	$ 259,918		
13							
14	Transmission Class	SD-21	$ 44,125	$ 44,125	$ -	0.00%	**0.00%**
15							
16			**$ 110,168**	**$ 2,425,740**	**$ 2,315,572**	100.00%	100.00%
17							
18	Notes:						
19	[1] Assumes that Medium Primary Service and Transmission Class revenues will not change due to the power factor adjustment change						

Work Paper 11 - STP - FPP O&M

Purpose: Adjustment to Test Year for O&M Expenses Associated with South Texas Project and Fayette Power Plant Operations

Line No.	FERC Account		Actual & Estimate Source Reference	FY 2009 Actual	FY 2010 Actual	FY 2011 Estimate	Three-Year Ave FY 2009 - FY 2011	Total Adjustment
A	B		C	D	E	F	G	H
1	**South Texas Project**							
2	426	Donations	WP 11.1	$ 38,342	$ 46,281	$ 39,435	$ 41,353	$ 3,011
3	517	Nuclear Operation Supervision	WP 11.1	8,972,486	8,914,267	8,099,638	8,662,131	(310,355)
4	519	Coolants And Water	WP 11.1	953,232	1,101,830	1,055,965	1,037,009	83,777
5	520	Nuclear Steam Expenses	WP 11.1	1,458,922	2,385,014	2,038,545	1,960,827	501,905
6	523	Nuclear Electric Expenses	WP 11.1	4,134,216	4,445,545	4,397,193	4,325,651	191,435
7	524	Misc Nuclear Power Expenses	WP 11.1	7,956,368	8,401,271	8,079,457	8,145,699	189,331
8	525	Nuclear Rents	WP 11.1	-	-	-	-	-
9	528	Nuclear Maintenance Supervision	WP 11.1	4,898,622	6,427,993	6,826,510	6,051,042	1,152,420
10	529	Nuclear Maintenance Of Structures	WP 11.1	2,347,069	3,211,876	2,507,232	2,688,726	341,657
11	530	Nuclear Maintenance Of Reactor Plant	WP 11.1	5,620,149	8,275,211	7,537,177	7,144,179	1,524,030
12	531	Nuclear Maintenance Of Electric Plant	WP 11.1	2,852,587	4,467,395	3,377,666	3,565,883	713,296
13	532	Maintenance Of Miscellaneous Nuclear Plant	WP 11.1	662,509	873,297	710,114	748,640	86,131
14	920	Administrative And General Salaries	WP 11.1	1,913,089	2,574,577	2,487,859	2,325,175	412,086
15	921	Office Supplies & Expenses	WP 11.1	479,503	526,925	420,864	475,764	(3,739)
16	922	Admin. Exp. Transferred -- credit	WP 11.1	(163,292)	(252,489)	(102,175)	(172,652)	(9,360)
17	923	Outside Services Employed	WP 11.1	1,513,819	975,706	791,115	1,093,547	(420,272)
18	924	Property Insurance	WP 11.1	425,511	639,888	521,895	529,098	103,587
19	925	Injuries And Damages	WP 11.1	384,328	349,867	387,157	373,784	(10,544)
20	926	Employee Pensions And Benefits	WP 11.1	8,289,952	8,480,969	9,596,619	8,789,180	499,228
21	930	General Expenses	WP 11.1	749,995	790,337	796,334	778,889	28,893
22	935	Maintenance Of General Plant	WP 11.1	874,593	1,020,004	931,424	942,007	67,414
23	**Total STP O&M**			$ 54,361,999	$ 63,655,763	$ 60,500,024	$ 59,505,929	$ 5,143,930
24								

Work Paper 11 - STP - FPP O&M
Purpose: Adjustment to Test Year for O&M Expenses Associated with South Texas Project and Fayette Power Plant Operations

Line No.	FERC Account		Actual & Estimate Source Reference	FY 2009 Actual	FY 2010 Actual	FY 2011 Estimate	Three-Year Ave FY 2009 - FY 2011	Total Adjustment
A	B		C	D	E	F	G	H
25	**Fayette Power Plant**							
26	408	Taxes Other Than Income	WP 11.1	$ (0)	$ -	$ 52,214	$ 17,405	$ 17,405
27	426	Donations	WP 11.1	(0)	-	-	(0)	0
28	500	Steam Generation Oper Superv And Engineering	WP 11.1	780,351	813,886	662,185	752,141	(28,211)
29	501	Steam Generation - Fuel	WP 11.1	3,731,980	5,115,968	4,910,703	4,586,217	854,237
30	502	Steam Expenses	WP 11.1	1,178,464	768,539	735,611	894,205	(284,260)
31	505	Electric Expenses	WP 11.1	4,958,918	724,814	785,230	2,156,321	(2,802,598)
32	506	Miscellaneous Steam Power	WP 11.1	2,601,966	2,654,380	2,753,551	2,669,966	68,000
33	510	Steam Maintenance Supervision	WP 11.1	-	33,754	260,681	98,145	98,145
34	511	Steam Maintenance Of Structures	WP 11.1	144,351	151,668	268,043	188,021	43,670
35	512	Steam Maintenance Of Boiler Plant	WP 11.1	4,616,691	3,684,413	5,473,068	4,591,391	(25,300)
36	513	Steam Maintenance Of Electric Plant	WP 11.1	1,496,298	2,208,561	4,124,132	2,609,663	1,113,366
37	514	Maintenance Of Misc Steam Plant	WP 11.1	1,312,974	1,374,903	2,175,869	1,621,249	308,275
38	557	Other Power Expenses	WP 11.1	26,189	10,684	78,604	38,493	12,303
39	570	Transmission Maintenance Of Station Equipment	WP 11.1	40,331	112,496	17,400	56,742	16,411
40	922	Admin. Exp. Transferred -- credit	WP 11.1	(125,415)	1,432,489	2,100,737	1,135,937	1,261,352
41	924	Property Insurance	WP 11.1	233,550	-	-	77,850	(155,700)
42	925	Injuries And Damages	WP 11.1	125,803	635,271	240,259	333,778	207,975
43	926	Employee Pensions And Benefits	WP 11.1	3,249,249	3,262,604	3,491,347	3,334,400	85,151
44	930	General Expenses	WP 11.1	1,070,546	189,319	-	419,955	(650,591)
45	**Total FPP O&M**			$ 25,442,246	$ 23,173,749	$ 28,129,632	$ 25,581,876	$ 139,630
46								
47	**Adjustment for Fayette Power Plant Ash Pond Liability** [1]							
48	505	Accrual of Liability	SD-26	$ (3,875,000)	$ -	$ -	$ (1,291,667)	$ (1,291,667)
49	505	Assumed Amortization of Liability (over five years)		775,000	775,000	775,000	775,000	775,000
50	**Adjusted FPP O&M**			$ 22,342,246	$ 23,948,749	$ 28,904,632	$ 25,065,209	$ (377,037)
51								
52	Notes:							
53		[1] Fayette Power Plant ash pond liability accrued in FY 2009 assumed to be amortized equally over five years, as expense is projected to be incurred through FY 2014						

Work Paper 11.1 - STP - FPP O&M

Purpose: Detail Historical O&M Expenses Associated with South Texas Project and Fayette Power Plant Operations

Line No.	FERC Account		Actual and YTD Source Reference	FY 2007 Actual	FY 2008 Actual	FY 2009 Actual	FY 2010 Actual	FY 2011 YTD - 9 Mo.	FY 2011 Estimate [1,2]
A	B		C	D	E	F	G	H	I
1	**South Texas Project**								
2	426	Donations	SD-80	$ 16,623	$ 37,136	$ 38,342	$ 46,281	$ 29,576	$ 39,435
3	517	Nuclear Operation Supervision	SD-80	7,565,439	8,356,872	8,972,486	8,914,267	6,074,729	8,099,638
4	519	Coolants And Water	SD-80	945,876	934,282	953,232	1,101,830	791,974	1,055,965
5	520	Nuclear Steam Expenses	SD-80	1,045,208	1,461,797	1,458,922	2,385,014	1,528,909	2,038,545
6	523	Nuclear Electric Expenses	SD-80	3,882,344	3,969,805	4,134,216	4,445,545	3,297,895	4,397,193
7	524	Misc Nuclear Power Expenses	SD-80	8,112,033	7,723,189	7,956,368	8,401,271	6,059,593	8,079,457
8	525	Nuclear Rents	SD-80	-	-	-	-	-	-
9	528	Nuclear Maintenance Supervision	SD-80	5,208,204	4,873,994	4,898,622	6,427,993	5,119,883	6,826,510
10	529	Nuclear Maintenance Of Structures	SD-80	2,500,088	2,068,619	2,347,069	3,211,876	1,880,424	2,507,232
11	530	Nuclear Maintenance Of Reactor Plant	SD-80	7,640,005	6,115,534	5,620,149	8,275,211	5,652,882	7,537,177
12	531	Nuclear Maintenance Of Electric Plant	SD-80	3,897,810	2,998,361	2,852,587	4,467,395	2,533,250	3,377,666
13	532	Maintenance Of Miscellaneous Nuclear Plant	SD-80	734,818	701,162	662,509	873,297	532,585	710,114
14	920	Administrative And General Salaries	SD-80	1,972,390	2,043,666	1,913,089	2,574,577	1,865,895	2,487,859
15	921	Office Supplies & Expenses	SD-80	427,806	355,815	479,503	526,925	315,648	420,864
16	922	Admin. Exp. Transferred -- credit	SD-80	-	(108,682)	(163,292)	(252,489)	(76,631)	(102,175)
17	923	Outside Services Employed	SD-80	834,147	893,417	1,513,819	975,706	593,336	791,115
18	924	Property Insurance	SD-80	311,933	325,527	425,511	639,888	391,421	521,895
19	925	Injuries And Damages	SD-80	235,529	292,061	384,328	349,867	290,368	387,157
20	926	Employee Pensions And Benefits	SD-80	5,838,811	6,019,253	8,289,952	8,480,969	7,197,464	9,596,619
21	930	General Expenses	SD-80	694,239	708,911	749,995	790,337	597,251	796,334
22	935	Maintenance Of General Plant	SD-80	657,570	748,347	874,593	1,020,004	698,568	931,424
23				$ 52,520,871	$ 50,519,067	$ 54,361,999	$ 63,655,763	$ 45,375,018	$ 60,500,024
24									
25	**Fayette Power Plant**								
26	408	Taxes Other Than Income	SD-26	$ 0	$ (0)	$ (0)	$ -	$ 39,160	$ 52,214
27	426	Donations	SD-26	772	0	(0)	-	-	-
28	500	Steam Generation Oper Superv And Engineering	SD-26	832,089	718,876	780,351	813,886	496,639	662,185
29	501	Steam Generation - Fuel	SD-26	4,115,900	4,762,871	3,731,980	5,115,968	3,683,027	4,910,703
30	502	Steam Expenses	SD-26	(792,764)	1,401,671	1,178,464	768,539	551,708	735,611
31	505	Electric Expenses	SD-26	2,623,096	1,018,302	4,958,918	724,814	588,922	785,230
32	506	Miscellaneous Steam Power	SD-26	2,320,443	3,292,657	2,601,966	2,654,380	2,065,163	2,753,551
33	510	Steam Maintenance Supervision	SD-26	-	-	-	33,754	195,511	260,681
34	511	Steam Maintenance Of Structures	SD-26	101,169	110,043	144,351	151,668	201,032	268,043
35	512	Steam Maintenance Of Boiler Plant	SD-26	3,149,211	3,787,569	4,616,691	3,684,413	4,104,801	5,473,068
36	513	Steam Maintenance Of Electric Plant	SD-26	2,046,233	1,819,847	1,496,298	2,208,561	3,093,099	4,124,132
37	514	Maintenance Of Misc Steam Plant	SD-26	1,472,460	1,338,628	1,312,974	1,374,903	1,631,902	2,175,869
38	557	Other Power Expenses	SD-26	51,713	8,637	26,189	10,684	58,953	78,604
39	570	Transmission Maintenance Of Station Equipment	SD-26	29,260	17,438	40,331	112,496	13,050	17,400
40	922	Admin. Exp. Transferred -- credit	SD-26	(892,345)	(1,447,179)	(125,415)	1,432,489	1,575,553	2,100,737
41	924	Property Insurance	SD-26	518,321	346,041	233,550	-	-	-
42	925	Injuries And Damages	SD-26	38,526	-	125,803	635,271	180,194	240,259
43	926	Employee Pensions And Benefits	SD-26	2,967,994	3,312,536	3,249,249	3,262,604	2,618,510	3,491,347
44	930	General Expenses	SD-26	695,191	878,946	1,070,546	189,319	-	-
45				$ 19,277,269	$ 21,366,882	$ 25,442,246	$ 23,173,749	$ 21,097,224	$ 28,129,632
46									

47 Notes:

48 [1] Based on FY 2011 Year-to-Date results (through June 2011) multiplied by 12/9 to annualize the results

49 [2] The original FY 2011 Budget amount for STP of $53,562,667 did not include the cost associated with a new Safety Review Project as a result of the Fukushima Daiichi plant in Japan.

50 In March 2011, the budget for STP was increased by $0.9 million due to this additional cost.

51 The original FY 2011 Budget amount for FPP was $27,017,991

Work Paper 12 - SHEC

Purpose: Summary of O&M Expenses Adjustments Associated with the Sand Hill Energy Center Due to LTSA and New Combustion Turbines

Line No.		FERC Account	Source Reference	FY 2009 Actual	Test Year	Total Adjustment
A		B	C	D	E	F
1	**Maintenance Contract**					
2	Maintenance-turbine/generator	553	WP 12.1	$ 3,814,314	$ 6,513,568	$ 2,699,254
3						
4	**Operation of New Gas Combustion Turbines**					
5	Total O&M for New CTs	548	WP 12.2	$ -	$ 1,448,193	$ 1,448,193
6						

Work Paper 12.1 - SHEC

Purpose: Adjustment of O&M Expenses Associated with Sand Hill Energy Center Due to LTSA

Line No.	Object Code		FERC Account	Source Reference	FY 2006 Actual	FY 2007 Actual	FY 2008 Actual	FY 2009 Actual	FY 2010 Actual	FY 2011 Estimated	Five-Year Ave [1] FY 2006 - FY 2010	Total Adjustment
A	B		C	D	E	F	G	H	I	J	K	L
1	6391	Maintenance-turbine/generator	553	SD-9	$ 5,901,934	$ 12,917,412	$ 3,728,987	$ 3,814,314	$ 6,205,193	$ 7,077,945	$ 6,513,568	$ 2,699,254
2					$ 5,901,934	$ 12,917,412	$ 3,728,987	$ 3,814,314	$ 6,205,193	$ 7,077,945	$ 6,513,568	$ 2,699,254
3												
4	Notes:											
5		[1] The maintenance contract for SHEC includes periodic over-haul expenses and, thus, a five-year average is necessary to capture these recurring, but uneven, contract costs.										

Work Paper 12.2 - SHEC

Purpose: Adjustment of O&M Expenses Associated with Sand Hill Energy Center Due to Operation of New Combustion Turbines

Line No.		Source Reference	Test Year
A		B	C
1	**Sand Hill Energy Center (SHEC)**		
2			
3	Description:	Added Two 45-MW LM6000 Units at Sand Hill Energy Center	
4	In Service Date:	July 2010	
5			
6	Test Year Generation (MWh)		
7	Unit 6	WP 44	24,907
8	Unit 7	WP 44	24,189
9			49,097
10			
11	Variable O&M ($/MWh)		
12	Unit 6	SD-22	$ 2.00
13	Unit 7	SD-22	$ 2.00
14			
15	Test Year Variable O&M for New CTs		
16	Unit 6		$ 49,815
17	Unit 7		48,378
18			$ 98,193
19			
20			
21	Capacity (MW)		
22	Unit 6	WP 41	45
23	Unit 7	WP 41	45
24			
25	Fixed Annual O&M ($/MW)		
26	Unit 6	SD-22	$ 15,000
27	Unit 7	SD-22	$ 15,000
28			
29	Test Year Fixed O&M for New CTs		
30	Unit 6		$ 675,000
31	Unit 7		675,000
32			$ 1,350,000
33			
34			
35	Test Year Total O&M for New CTs		
36	Unit 6		$ 724,815
37	Unit 7		723,378
38			**$ 1,448,193**

Work Paper 13 - Scrubber

Purpose: Adjust Test Year based on estimated O&M associated with new scrubbers at FPP

Line No.		Source Reference	FY 2009 Actual	Test Year
A		B	C	D
1	**Fayette Power Plant (FPP)**			
2				
3	Adjustment:		Pollution Prevention (Scrubbers) Added to the Fayette Power Plant	
4	In Service Date:		March 2011	
5				
6	**MWh**			
7	Unit 1	WP 44	1,736,955	2,269,021
8	Unit 2	WP 44	2,019,822	2,205,069
9			3,756,777	4,474,090
10				
11	**Incremental Fixed O&M**			
12	MW	SD-23		285
13	$/MW-Yr	SD-23		$ 4,300
14				$ 1,225,500
15				
16	**Incremental Variable O&M**			
17	MWh			4,474,090
18	$ / MWh	SD-23		$ 0.27
19				$ 1,208,004
20				
21	**Total Incremental O&M**			**$ 2,433,504**

Work Paper 14 - CIP

Purpose: Develop Test Year CIP Based on Historical and Projected CIP

Line No.		CIP Actual Source Reference	CIP Projected Source Reference	FY 2006 Actual	FY 2007 Actual	FY 2008 Actual	FY 2009 Actual	FY 2010 Projected	FY 2011 Projected	Three-Year Average FY 2009 - FY 2011
A		B	C	D	E	F	G	J	K	L
1	**CIP Funded by Revenues**									
2	Generation	SD-24	SD-6	$ 28,262,222	$ 24,184,797	$ 80,906,954	$ 63,599,743	$ 34,517,000	$ 29,326,000	$ 42,480,914
3	Transmission	SD-24	SD-6	8,880,445	8,675,858	10,048,122	12,628,211	6,320,000	8,422,400	9,123,537
4	Distribution	SD-24	SD-6	39,999,204	43,653,851	46,530,908	43,434,792	22,774,850	19,501,300	28,570,314
5	Customer	SD-24	SD-6	2,172,971	1,371,409	11,881,840	22,196,029	22,906,600	15,703,000	20,268,543
6	A&G	SD-24	SD-6	7,422,871	8,788,270	9,812,634	8,763,612	16,360,000	10,153,000	11,758,871
7	Street Lighting	SD-24	SD-6	1,665,457	1,998,529	2,689,038	2,047,733	1,349,950	1,691,200	1,696,294
8										
9				$ 88,403,170	$ 88,672,713	$ 161,869,496	$ 152,670,120	$ 104,228,400	$ 84,796,900	$ 113,898,473
10										
11	**CIP Funded by Bonds / Commercial Paper**									
12	Generation	SD-24	SD-6	$ 6,907,829	$ 26,283,972	$ 44,135,394	$ 56,468,742	$ 47,011,000	$ 29,500,000	$ 44,326,581
13	Transmission	SD-24	SD-6	5,256,702	5,450,840	6,250,366	7,170,492	9,480,000	12,633,600	9,761,364
14	Distribution	SD-24	SD-6	20,530,406	22,604,464	24,130,042	22,346,280	42,296,150	36,216,700	33,619,710
15	Customer	SD-24	SD-6	-	-	610,490	140,215	842,400	1,209,000	730,538
16	A&G	SD-24	SD-6	-	18,557,830	253,062	1,883,776	10,094,000	52,761,000	21,579,592
17	Street Lighting	SD-24	SD-6	896,784	1,076,131	1,446,337	1,102,625	2,507,050	3,140,800	2,250,158
18	Sub Total			$ 33,591,721	$ 73,973,236	$ 76,825,691	$ 89,112,130	$ 112,230,600	$ 135,461,100	$ 112,267,943
19										
20	Non-Utility	SD-24	SD-6	13,459,698	15,136,654	22,512,205	14,421,627	15,672,000	8,136,000	12,743,209
21										
22				$ 47,051,419	$ 89,109,890	$ 99,337,896	$ 103,533,756	$ 127,902,600	$ 143,597,100	$ 125,011,152
23										
24	**Total CIP**			**$ 135,454,589**	**$ 177,782,604**	**$ 261,207,391**	**$ 256,203,877**	**$ 232,131,000**	**$ 228,394,000**	**$ 238,909,626**
25										
26	**CIP Associated with Holly Decommissioning**									
27	Generation	SD-24	SD-6	$ -	$ -	$ 1,469,084	$ 1,957,181	$ 1,342,000	$ 8,654,000	$ 3,984,394
28										
29	**Total Electric Utility (Net of Holly Decommissioning)**									
30	Generation			$ 35,170,052	$ 50,468,769	$ 123,573,265	$ 118,111,304	$ 80,186,000	$ 50,172,000	$ 82,823,101
31	Transmission			14,137,146	14,126,698	16,298,488	19,798,703	15,800,000	21,056,000	18,884,901
32	Distribution			60,529,610	66,258,314	70,660,950	65,781,072	65,071,000	55,718,000	62,190,024
33	Customer			2,172,971	1,371,409	12,492,330	22,336,244	23,749,000	16,912,000	20,999,081
34	A&G			7,422,871	27,346,099	10,065,696	10,647,388	26,454,000	62,914,000	33,338,463
35	Street Lighting			2,562,241	3,074,660	4,135,375	3,150,358	3,857,000	4,832,000	3,946,453
36				$ 121,994,891	$ 162,645,950	$ 237,226,103	$ 239,825,069	$ 215,117,000	$ 211,604,000	**$ 222,182,023**
37										
38	**FPP Scrubbers (Included in Above)**	SD-24	SD-6	$ 6,907,829	$ 26,283,972	$ 44,135,394	$ 56,468,742	$ 35,011,000	$ 26,000,000	$ 39,159,914
39										

Work Paper 14 - CIP

Purpose: Develop Test Year CIP Based on Historical and Projected CIP

Line No.		CIP Actual Source Reference	CIP Projected Source Reference	FY 2006 Actual	FY 2007 Actual	FY 2008 Actual	FY 2009 Actual	FY 2010 Projected	FY 2011 Projected	Three-Year Average FY 2009 - FY 2011
A		B	C	D	E	F	G	J	K	L
40	**Total Electric Utility Net of Holly Decommissioning and FPP Scrubbers**									
41	Generation			$ 28,262,222	$ 24,184,797	$ 79,437,870	$ 61,642,562	$ 45,175,000	$ 24,172,000	$ 43,663,187
42	Transmission			14,137,146	14,126,698	16,298,488	19,798,703	15,800,000	21,056,000	18,884,901
43	Distribution			60,529,610	66,258,314	70,660,950	65,781,072	65,071,000	55,718,000	62,190,024
44	Customer			2,172,971	1,371,409	12,492,330	22,336,244	23,749,000	16,912,000	20,999,081
45	A&G			7,422,871	27,346,099	10,065,696	10,647,388	26,454,000	62,914,000	33,338,463
46	Street Lighting			2,562,241	3,074,660	4,135,375	3,150,358	3,857,000	4,832,000	3,946,453
47				$ 115,087,062	$ 136,361,977	$ 193,090,709	$ 183,356,327	$ 180,106,000	$ 185,604,000	$ 183,022,109
48										
49	**Test Year Total Electric Utility CIP**	**$ 222,182,023**								
50	Assumed Capital Structure									
51	Cash	50.0%								
52	Debt	50.0%								
53	Total	100.0%								
54										
55	Sources of Capital Funding									
56	Cash	$ 111,091,011								
57	Debt	111,091,011								
58	Total	$ 222,182,023								

Work Paper 14.1 - CIP

Purpose: Develop Allocation Factors for the Test Year CIP

Line No.		CIP Source Reference	Test Year CIP	Allocation Source Reference	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A		B	C	D	E	F	G	H	I	J
1	**CIP Allocation**									
2	Generation	WP 14	$ 43,663,187		Production	$ 43,663,187	$ -	$ -	$ -	$ 43,663,187
3	Transmission	WP 14	18,884,901		Transmission	-	18,884,901	-	-	18,884,901
4	Distribution	WP 14	62,190,024		Distribution	-	-	62,190,024	-	62,190,024
5	Customer	WP 14	20,999,081		Customer	-	-	-	20,999,081	20,999,081
6	A&G	WP 14	33,338,463	WP 3.1	A&G Labor	7,980,733	3,177,208	9,801,555	12,378,967	33,338,463
7	Street Lighting	WP 14	3,946,453		Distribution	-	-	3,946,453	-	3,946,453
8			$ 183,022,109			$ 51,643,920	$ 22,062,109	$ 75,938,032	$ 33,378,048	$ 183,022,109
9										
10		**CIP Net of FPP Scrubbers (for Allocation of Non-Scrubber Debt on WP 5)**				**28.2%**	**12.1%**	**41.5%**	**18.2%**	**100.0%**
11										
12	FPP Scrubbers	WP 14	$ 39,159,914		Production	$ 39,159,914	$ -	$ -	$ -	$ 39,159,914
13										
14	Total Electric Utility CIP		$ 222,182,023			$ 90,803,834	$ 22,062,109	$ 75,938,032	$ 33,378,048	$ 222,182,023
15										
16				**Total CIP (for Functional Unbundling)**		**40.9%**	**9.9%**	**34.2%**	**15.0%**	**100.0%**

Work Paper 15 - Other Revenue

Purpose: Detail Other (i.e., Non-Rate) Revenue to Facilitate Adjustments (as needed)

Line No.		FY 2009 Source Reference	Adjustment Source Reference	FY 2009 Actual	Adjustments	Test Year	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A		B	C	D	E	F	G	H	I	J	K	L
1	**Operating Revenue**											
2	91104222 Late Payment Penalties	SD-25		$ 5,138,023		$ 5,138,023	Customer	$ -	$ -	$ -	$ 5,138,023	$ 5,138,023
3	91804233 Facilities Rentals	SD-25		2,679,724		2,679,724	Distribution	-	-	2,679,724	-	2,679,724
4	91104475 Transmission Services	SD-25	Calculated [1]	57,003,423	10,066,863	67,070,286	Transmission	-	67,070,286	-	-	67,070,286
5	91804426 Whsle Trans Srv-Dist Voltage	SD-25		83,997		83,997	Distribution	-	-	83,997	-	83,997
6	91804454 Construction	SD-25		-		-	Distribution	-	-	-	-	-
7	91104477 Banners	SD-25		53,800		53,800	Customer	-	-	-	53,800	53,800
8	91104481 Meter Damages/Breakage	SD-25		224,201		224,201	Distribution	-	-	224,201	-	224,201
9	91104747 Electric Meter Damage	SD-25		42,252		42,252	Distribution	-	-	42,252	-	42,252
10	91104748 Broken Seal Fee	SD-25		67,860		67,860	Distribution	-	-	67,860	-	67,860
11	91104749 Labor & Support	SD-25		176,522		176,522	Customer	-	-	-	176,522	176,522
12	91104879 Cash Over/Short	SD-25		-		-		-	-	-	-	-
13	91514222 Chilled Water Late Payments	SD-25	Remove [2]	3,027	(3,027)	-		-	-	-	-	-
14	91514429 Chilled Water Ecwdt	SD-25	Remove [2]	6,096,127	(6,096,127)	-		-	-	-	-	-
15	91514431 Chilled Water Domain	SD-25	Remove [2]	3,493,108	(3,493,108)	-		-	-	-	-	-
16	91514751 Chilled Water Seton-Dellchp	SD-25	Remove [2]	1,868,490	(1,868,490)	-		-	-	-	-	-
17	91514752 Steam Svc Dell Children Hosp	SD-25	Remove [2]	437,239	(437,239)	-		-	-	-	-	-
18	91514432 Steam Svc Domain Plant	SD-25	Remove [2]	477,279	(477,279)	-		-	-	-	-	-
19	91514433 Compressed Air Domain Plt	SD-25	Remove [2]	119,335	(119,335)	-		-	-	-	-	-
20	91514581 911 Call Center Sales	SD-25		307,972		307,972	Distribution	-	-	307,972	-	307,972
21	91304806 Balance Transfers-Util Accts	SD-25		(29,210)		(29,210)	Customer	-	-	-	(29,210)	(29,210)
22	91104940 Sale Of Fixed Assets	SD-25		-		-		-	-	-	-	-
23	91104491 Emergency Outage/Restoration	SD-25		57,122		57,122	Distribution	-	-	57,122	-	57,122
24	91314544 Sales Construction	SD-25		106,067		106,067	Distribution	-	-	106,067	-	106,067
25	91314545 Sales-Metering: Install Only	SD-25		6,955		6,955	Distribution	-	-	6,955	-	6,955
26	91314546 Sales-Reoccur Monthly Charge	SD-25		82,946		82,946	Customer	-	-	-	82,946	82,946
27	91314547 Sales -Special	SD-25		60,772		60,772	Production	60,772	-	-	-	60,772
28	91314552 Sales - Reliability Enhancement.	SD-25		800		800	Distribution	-	-	800	-	800
29	91314551 Sales - Sec Main	SD-25		68,697		68,697	Distribution	-	-	68,697	-	68,697
30				$ 78,626,528	$ (2,427,743)	$ 76,198,786		$ 60,772	$ 67,070,286	$ 3,645,647	$ 5,422,082	$ 76,198,786
31												
32	**Non-Operating Revenue**											
33	91514260 Facility Maintenance	SD-25	Remove [2]	$ 1,305,266	$ (1,305,266)	$ -		$ -	$ -	$ -	$ -	$ -
34	91704273 T-Tower Usage Fees	SD-25		760,287		760,287	Transmission	-	760,287	-	-	760,287
35	91104457 Sale Of S02 Allowance	SD-25		(596,724)		(596,724)	Production	(596,724)	-	-	-	(596,724)
36	91104039 Reinspection Fee	SD-25		13,031		13,031	Distribution	-	-	13,031	-	13,031
37	91314549 Sales-Prim Maint/Emerg Out Res	SD-25		8,605		8,605	Distribution	-	-	8,605	-	8,605
38	91314458 Solar Explorer Prgm	SD-25	Remove [3]	19,807	(19,807)	-	Production	-	-	-	-	-
39	91304479 After Hours Turn/On	SD-25		1,411,572		1,411,572	Distribution	-	-	1,411,572	-	1,411,572
40	91304480 Area Lighting Prgm	SD-25		29,585		29,585	Distribution	-	-	29,585	-	29,585
41	91304514 Green Building Sales	SD-25		9,270		9,270	Production	9,270	-	-	-	9,270
42	91304515 Green Building Consulting	SD-25		97,720		97,720	Production	97,720	-	-	-	97,720
43	91304809 Accts Rec-Adjustments	SD-25		8,529		8,529	Customer	-	-	-	8,529	8,529
44	91304855 Apt Mgr Initiation Fee	SD-25		195,080		195,080	Customer	-	-	-	195,080	195,080
45	91804861 Infrastr Contract Assess-Distr	SD-25		15,860		15,860	Distribution	-	-	15,860	-	15,860
46	91704861 Infrastr Contract Assess-Tran	SD-25		-		-	Transmission	-	-	-	-	-
47	91704866 Tower Application Fees	SD-25		21,000		21,000	Distribution	-	-	21,000	-	21,000
48	91304867 Analytical Lab Fees	SD-25		11,636		11,636	Production	11,636	-	-	-	11,636
49	91104874 Miscellaneous Rev-Oper	SD-25		120,003		120,003	Misc Op Rev 4874	108,000	-	12,003	-	120,003

Work Paper 15 - Other Revenue

Purpose: Detail Other (i.e., Non-Rate) Revenue to Facilitate Adjustments (as needed)

Line No.		FY 2009 Source Reference	Adjustment Source Reference	FY 2009 Actual	Adjustments	Test Year	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A		B	C	D	E	F	G	H	I	J	K	L
50	91304874 Miscellaneous Rev-Nonop	SD-25		17,346		17,346	Misc Non-Op Rev 4874	1,509	207	15,631	-	17,346
51	91304875 Returned Check Fee	SD-25		120,359		120,359	Customer	-	-	-	120,359	120,359
52	91304428 EFT Decline Fee	SD-25		31,750		31,750	Customer	-	-	-	31,750	31,750
53	91104877 Junk/Scrap	SD-25		915,511		915,511	Distribution	-	-	915,511	-	915,511
54	91304877 Junk/Scrap	SD-25		-		-	Distribution	-	-	-	-	-
55	91004879 Cash Over/Short	SD-25		6		6	Customer	-	-	-	6	6
56	91304879 Cash Over/Short	SD-25		-		-	Transmission	-	-	-	-	-
57	91304880 Non-Recurring Revenue	SD-25		-		-		-	-	-	-	-
58	91304881 Sales Tax Discount	SD-25		134,345		134,345	Customer	-	-	-	134,345	134,345
59	91804882 Pole Application Fee	SD-25		53,525		53,525	Distribution	-	-	53,525	-	53,525
60	91304883 New Service Connections	SD-25		2,866,570		2,866,570	Distribution	-	-	2,866,570	-	2,866,570
61	91304889 Construction Loop Fee	SD-25		86,725		86,725	Distribution	-	-	86,725	-	86,725
62	91804894 Infrastructure Misc Rev-Distr	SD-25		253,481		253,481	Distribution	-	-	253,481	-	253,481
63	91704894 Infrastructure Misc Rev-Tran	SD-25		1,000,107		1,000,107	Transmission	-	1,000,107	-	-	1,000,107
64	91304952 Rentals Non Operating	SD-25		24,228		24,228	Misc Non-Op Rev 4952	20,885	-	3,343	-	24,228
65	91104952 Rentals Operating	SD-25		18,333		18,333	Production	18,333	-	-	-	18,333
66	91304953 FPP Rental	SD-25		956,551		956,551	Production	956,551	-	-	-	956,551
67	91424812 Interdpt Water	SD-25		-		-	Distribution	-	-	-	-	-
68	91424816 Interdpt Convention Ctr	SD-25		20,624		20,624	Customer	-	-	-	20,624	20,624
69	91424811 Interdpt Electric	SD-25		-		-	Distribution	-	-	-	-	-
70	91424849 Interdpt Health	SD-25		-		-	Distribution	-	-	-	-	-
71	91114333 ERCOT Svc Rev-Capacity	SD-25	Remove [4]	4,379,381	(4,379,381)	-	Production	-	-	-	-	-
72	91114334 ERCOT Svc Rev-Energy	SD-25	Remove [4]	6,977,166	(6,977,166)	-	Production	-	-	-	-	-
73	91114340 ERCOT Other Revenue	SD-25		-		-	Production	-	-	-	-	-
74	91114365 ERCOT TCR Revenues	SD-25	Remove [4]	6,895,752	(6,895,752)	-	Production	-	-	-	-	-
75	91204378 Sale Plans & Specs	SD-25		-		-	Distribution	-	-	-	-	-
76				$ 28,182,287	$ (19,577,372)	$ 8,604,915		$ 627,179	$ 1,760,601	$ 5,706,442	$ 510,693	$ 8,604,915
77												
78				**$ 106,808,816**	**$ (22,005,115)**	**$ 84,803,701**		**$ 687,951**	**$ 68,830,887**	**$ 9,352,089**	**$ 5,932,775**	**$ 84,803,701**
79												

80 Notes:

81 [1] Calculated to set revenue from Transmission Services equal to the Transmission COS (except wheeling - FERC 565)

82 [2] Remove non-electric revenue from the Test Year

83 [3] Solar Explorer program to be discontinued

84 [4] Assumed benefit is passed back through the fuel charge, making customers whole if the revenue is realized

Work Paper 16 - Fuel

Purpose: Summarize Recoverable and Non-Recoverable Fuel Costs for FY 2009

Line No.		FERC Account	Source Reference	Recoverable	Non Recoverable [1]	FY 2009 Actual
A		B	C	D	E	F
1	**Fuel Cost**					
2		501	SD-8	$ 299,909,760	$ 4,083,544	$ 303,993,304
3		518	SD-8	16,866,183	-	16,866,183
4		547	SD-8	4,206	-	4,206
5		555	SD-8	78,830,176	26,856,820	105,686,996
6		556	SD-8	12,791,041	9,921,783	22,712,824
7				**$ 408,401,366**	**$ 40,862,146**	**$ 449,263,512**
8						

9 Notes:

10 [1] Non-recoverable fuel costs include billed Green Choice costs (all of FERC 555 - wind and some
11 of FERC 556 - congestion).

Work Paper 17 - Uncollectible

Purpose: Adjustment Uncollectible Accounts to Reflect the Impact of the Test Year Revenue Requirement

Line No.		FY 2009 Source Reference	FY 2009 Actual	Normalized Customer Months	Customer Weighting	FY 2009 Allocated Uncollectible Cost	Test Year COS Source Reference	Change In Test Year COS	Test Year	Total Adjustment
A		B	C	D	E	F	G	H	I	J
1	**Uncollectible Accounts**	Functional Unbundling	$ 3,649,195							
2										
3										
4	**Secondary Service less than 50 KW, Excluding Street Lighting, State, City and School Accounts**									
5	Residential	WP 22		4,374,252	89.8%	$ 3,277,682	COS	28.7%	$ 4,217,429	$ 939,748
6	Secondary Voltage < 10 kW	WP 22		376,651	7.7%	282,230	COS	27.5%	359,856	77,626
7	Secondary Voltage 10 - 49.9 kW	WP 22		119,154	2.4%	89,284	COS	3.6%	92,502	3,218
8	Secondary Voltage ≥ 50 kW	WP 22		-	0.0%	-	COS	0.6%	-	-
9	Primary Voltage < 3 MW	WP 22		-	0.0%	-	COS	-3.9%	-	-
10	Primary Voltage 3 - 19.9 MW	WP 22		-	0.0%	-	COS	9.8%	-	-
11	Primary Voltage ≥ 20 MW	WP 22		-	0.0%	-	COS	8.8%	-	-
12	Transmission Voltage	WP 22		-	0.0%	-	COS	-10.3%	-	-
13	Service Area Street Lighting	WP 22		-	0.0%	-	COS		-	-
14	AE-Owned Private Outdoor Lighting	WP 22		-	0.0%	-	COS	97.4%	-	-
15	Non-Metered Lighting	WP 22		-	0.0%	-	COS	34.4%	-	-
16	Metered Lighting	WP 22		-	0.0%	-	COS	126.8%	-	-
17				4,870,058	100.0%	$ 3,649,195			**$ 4,669,787**	**$ 1,020,593**

Work Paper 18 - Interest

Purpose: Adjustment of Interest and Dividend Income for the Test Year

Line No.		FY 2009 & FY 2010 Source Reference	FY 2009 Actual	FY 2010 Actual	Increase / (Decrease)	Additional Adjustment Source Reference	Utilize FY 2010 Basis	Additional Adjustments	Test Year
A		B	C	D	E	F	G	H	I
1	4219 Electric CIP	SD-27	$ 1,793,315	$ 868,892	$ (924,423)		$ 868,892	$ -	$ 868,892
2	4221 Operating Interest	SD-27	6,983,879	2,269,362	(4,714,517)		2,269,362	-	2,269,362
3	4951 FPP Int Rev	SD-27	318,609	296,760	(21,849)		296,760	-	296,760
4	4276 Electric Escrow Int	SD-27	44,235	4,968	(39,267)		4,968	-	4,968
5	4228 Misc Interest	SD-27	406,661	82,119	(324,542)		82,119	-	82,119
6	4220 Decommissioning	SD-27	5,004,129	4,022,289	(981,840)	Remove [1]	4,022,289	(4,022,289)	-
7	4224 Reserve Funds	SD-27	5,594,377	4,074,509	(1,519,868)		4,074,509	-	4,074,509
8	4902 Unrealized Gain	SD-27	(2,743,643)	(726,504)	2,017,139	Remove [2]	(726,504)	726,504	-
9	4903 Unrealized Loss	SD-27	-	(1,152,020)	(1,152,020)	Remove [2]	(1,152,020)	1,152,020	-
10			$ 17,401,562	$ 9,740,374	$ (7,661,188)		$ 9,740,374	$ (2,143,765)	$ 7,596,609
11									
12	Notes:								
13	[1] Not available to offset costs to be recovered from rates								
14	[2] Non-cash								

Work Paper 18 - Interest

Purpose: Adjustment of Interest and Dividend Income for the Test Year

Line No.		FY 2009 & FY 2010 Source Reference	FY 2009 Actual	Total Adjustment	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A		B	C	J	M	N	O	P	Q	R
1	4219 Electric CIP	SD-27	$ 1,793,315	$ (924,423)	CIP-Total	$ 355,108	$ 86,279	$ 296,972	$ 130,532	$ 868,892
2	4221 Operating Interest	SD-27	6,983,879	(4,714,517)	OMAG	1,084,367	438,211	369,963	376,821	2,269,362
3	4951 FPP Int Rev	SD-27	318,609	(21,849)	Production	296,760	-	-	-	296,760
4	4276 Electric Escrow Int	SD-27	44,235	(39,267)	Customer	-	-	-	4,968	4,968
5	4228 Misc Interest	SD-27	406,661	(324,542)	OMAG	39,239	15,857	13,387	13,636	82,119
6	4220 Decommissioning	SD-27	5,004,129	(5,004,129)		-	-	-	-	-
7	4224 Reserve Funds	SD-27	5,594,377	(1,519,868)	OMAG	1,946,919	786,783	664,247	676,560	4,074,509
8	4902 Unrealized Gain	SD-27	(2,743,643)	2,743,643		-	-	-	-	-
9	4903 Unrealized Loss	SD-27	-	-		-	-	-	-	-
10			$ 17,401,562	$ (9,804,953)		$ 3,722,393	$ 1,327,129	$ 1,344,570	$ 1,202,516	$ 7,596,609
11										
12	Notes:									
13	[1] Not available to offset costs to be recovered from rates									
14	[2] Non-cash									

Work Paper 19 - Non-Electric Expense

Purpose: Adjustments to Selected O&M Expenses to Remove Non-Electric Expenses from the Test Year

Line No.		FERC Account	Source Reference	FY 2009 Actual	Adjustment	Test Year	Total Adjustment
A		B	C	D	E	F	G
1	Expenses - Non-utility operations	417	WP 19.1	$ 16,288,944	$ (10,077,720)	$ 6,211,223	$ (10,077,720)
2	Misc Service Revenue	451	WP 19.1	22,056	(497)	21,559	(497)
3	Operation Supervision and Engineering	500	WP 19.1	8,461,250	-	8,461,250	-
4	Maintenance of Miscellaneous Steam Plant	514	WP 19.1	3,553,188	(11,970)	3,541,218	(11,970)
5	Operation Supervision	546	WP 19.1	2,356,493	(613,208)	1,743,285	(613,208)
6	Generation Expenses	548	WP 19.1	2,489,508	(330)	2,489,178	(330)
7	Miscellaneous Other Power Generation Expenses	549	WP 19.1	130,467	(32,164)	98,303	(32,164)
8	Rents	550	WP 19.1	205,134	-	205,134	-
9	Maintenance of Structures	552	WP 19.1	105,620	(210)	105,410	(210)
10	Maintenance of Misc Other Power Generation Plant	554	WP 19.1	1,169,131	(455)	1,168,676	(455)
11	Underground Line Expenses	584	WP 19.1	(674,154)	(573)	(674,727)	(573)
12	Supervision	907	WP 19.1	3,237,337	(320)	3,237,017	(320)
13	Administrative and General Salaries	920	WP 19.1	38,780,376	-	38,780,376	-
14	Office Supplies and Expenses	921	WP 19.1	28,007,506	(2,410)	28,005,096	(2,410)
15	General Expenses	930	WP 19.1	22,428,040	(324)	22,427,716	(324)
16				$ 126,560,895	$ (10,740,180)	$ 115,820,714	$ (10,740,180)

Work Paper 19.1 - Non-Electric Expense

Purpose: Detail on Selected O&M Expenses to Facilitate Removal of Non-Electric Expenses from the Test Year

Line No.		FERC 417 Source Reference	Other Expenses Source Reference	FERC 417	FERC 451	FERC 500	FERC 514	FERC 546	FERC 548	FERC 549	FERC 550
A				B	C	D	E	F	G	H	I
1	**Non-Electric Expenses by FERC**										
2	1124 Energy Products	SD-29	SD-28	$ 175,748	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	2202 Fm812 Landfill	SD-29	SD-28	3,602	-	-	-	-	-	-	-
4	2221 Downtown Plant-Chilled Water	SD-29	SD-28	1,872,393	-	-	-	24,316	-	-	-
5	2222 Admin For District Energy	SD-29	SD-28	1,395,849	-	-	-	-	-	-	-
6	2223 Lamar And 6Th Chilled Water	SD-29	SD-28	30,376	-	-	-	-	-	-	-
7	2224 N. Burnet Dist Energy (Domain)	SD-29	SD-28	3,234,020	497	-	4,365	560	-	-	-
8	2225 911 Call Center-Chilled Water	SD-29	SD-28	770,090	-	-	755	-	-	-	-
9	2226 Bchp-Chiller	SD-29	SD-28	22,771	-	-	-	-	-	-	-
10	2227 Bchp-Gas Turbine	SD-29	SD-28	-	-	-	-	-	-	-	-
11	2229 911 Call Center Chilled H20 Op	SD-29	SD-28	174,688	-	-	-	-	-	-	-
12	2230 911 Back-Up Center	SD-29	SD-28	153,513	-	-	-	-	-	-	-
13	2232 Rmec - District Energy	SD-29	SD-28	1,670,117	-	-	6,850	588,332	330	32,164	-
14	2233 Convention Center Plant-Dcp	SD-29	SD-28	656,504	-	-	-	-	-	-	-
15	2234 Rmec- Generation	SD-29	SD-28	-	-	-	-	-	-	-	-
16	1306 General Operations	SD-29	SD-28	(125,582)	-	-	-	-	-	-	-
17	1310 Corporate Improvement Services	SD-29	SD-28	414	-	-	-	-	-	-	-
18	1350 Office Of Chief Operating Officer	SD-29	SD-28	2,175	-	-	-	-	-	-	-
19	2100 Environmental Management	SD-29	SD-28	618	-	-	-	-	-	-	-
20	2102 Environmental Field Service	SD-29	SD-28	1,022	-	-	-	-	-	-	-
21	7798 One Stop Shop Support	SD-29	SD-28	-	-	-	-	-	-	-	-
22	8821 Call Cntr City Wide Info Cntr	SD-29	SD-28	172	-	-	-	-	-	-	-
23	1112 Human Resources	SD-29	SD-28	13,382	-	-	-	-	-	-	-
24	2212 Generation Plant Support	SD-29	SD-28	24,575	-	-	-	-	-	-	-
25	2227 Bchp-Gas Turbine	SD-29	SD-28	-	-	-	-	-	-	-	-
26	2234 Rmec- Generation	SD-29	SD-28	-	-	-	-	-	-	-	-
27	3510 Network Construction	SD-29	SD-28	1,276	-	-	-	-	-	-	-
28				$ 10,077,720	$ 497	$ -	$ 11,970	$ 613,208	$ 330	$ 32,164	$ -
29											
30	**Electric Expenses**										
31	2227 Bchp-Gas Turbine	SD-29		$ 945	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	2234 Rmec- Generation	SD-29		251,657	-	-	-	-	-	-	-
33				$ 252,602	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Work Paper 19.1 - Non-Electric Expense

Line No.		FERC 552	FERC 554	FERC 584	FERC 907	FERC 920	FERC 921	FERC 930	Total
A		J	K	L	M	N	O	P	Q
1	**Non-Electric Expenses by FERC**								
2	1124 Energy Products	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 175,748
3	2202 Fm812 Landfill	-	-	-	-	-	-	-	3,602
4	2221 Downtown Plant-Chilled Water	-	455	-	-	-	229	-	1,897,393
5	2222 Admin For District Energy	-	-	-	-	-	-	-	1,395,849
6	2223 Lamar And 6Th Chilled Water	-	-	-	-	-	-	-	30,376
7	2224 N. Burnet Dist Energy (Domain)	-	-	573	-	-	1,265	-	3,241,280
8	2225 911 Call Center-Chilled Water	-	-	-	-	-	916	-	771,760
9	2226 Bchp-Chiller	-	-	-	-	-	-	-	22,771
10	2227 Bchp-Gas Turbine	-	-	-	-	-	-	-	-
11	2229 911 Call Center Chilled H20 Op	-	-	-	-	-	-	-	174,688
12	2230 911 Back-Up Center	-	-	-	320	-	-	-	153,832
13	2232 Rmec - District Energy	210	-	-	-	-	-	324	2,298,327
14	2233 Convention Center Plant-Dcp	-	-	-	-	-	-	-	656,504
15	2234 Rmec- Generation	-	-	-	-	-	-	-	-
16	1306 General Operations	-	-	-	-	-	-	-	(125,582)
17	1310 Corporate Improvement Services	-	-	-	-	-	-	-	414
18	1350 Office Of Chief Operating Officer	-	-	-	-	-	-	-	2,175
19	2100 Environmental Management	-	-	-	-	-	-	-	618
20	2102 Environmental Field Service	-	-	-	-	-	-	-	1,022
21	7798 One Stop Shop Support	-	-	-	-	-	-	-	-
22	8821 Call Cntr City Wide Info Cntr	-	-	-	-	-	-	-	172
23	1112 Human Resources	-	-	-	-	-	-	-	13,382
24	2212 Generation Plant Support	-	-	-	-	-	-	-	24,575
25	2227 Bchp-Gas Turbine	-	-	-	-	-	-	-	-
26	2234 Rmec- Generation	-	-	-	-	-	-	-	-
27	3510 Network Construction	-	-	-	-	-	-	-	1,276
28		$ 210	$ 455	$ 573	$ 320	$ -	$ 2,410	$ 324	$ 10,740,180
29									
30	**Electric Expenses**								
31	2227 Bchp-Gas Turbine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 945
32	2234 Rmec- Generation	-	-	-	-	-	-	-	251,657
33		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 252,602

Work Paper 20 - Off-System

Purpose: Detail Off-System Sales to Ensure Removal from the Test Year

Line No.		Source Reference		FY 2009 Actual
A		B		C
1	Off-System Sales in Base Revenue	SD-18	$	4,244,043
2	Off-System Sales in Fuel Revenue - Fuel	SD-18		12,633,914
3	Off-System Sales in Fuel Revenue - ERCOT Fuel	SD-18		8,740,926
4	Ancillary Services in Other Revenue			
5	ERCOT SVC Rev-Capacity	WP 15		4,379,381
6	ERCOT SVC Rev-Energy	WP 15		6,977,166
7	ERCOT TCR Revenues	WP 15		6,895,752
8				
9	Total Revenue		$	43,871,182
10				
11	Fuel Expense	SD-18	$	(21,657,426)
12				
13	Net Revenue		$	22,213,757
14				

Work Paper 21 - Demand and Energy

Purpose: Demand and Energy Data for Development of Production Related Allocation Factors

Line No.	Allocation Factor	Source Reference	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW	Primary Voltage ≥ 20 MW	Transmission Voltage
A	B	C	D	E	F	G	H	I	J	K
1										
2	**Normalized Load Research Data**									
3										
4	Coincident Peak (kW)									
5	Oct-08	SD-30	721,770	98,318	207,547	756,458	59,650	100,008	123,067	29,804
6	Nov-08	SD-30	434,852	87,690	181,709	680,325	57,519	98,137	119,018	32,584
7	Dec-08	SD-30	740,612	72,850	160,104	591,268	45,701	85,320	111,358	24,080
8	Jan-09	SD-30	703,324	66,242	129,771	551,017	44,690	87,056	107,231	25,903
9	Feb-09	SD-30	421,460	84,974	180,723	598,615	51,178	94,412	115,613	29,772
10	Mar-09	SD-30	502,716	75,865	138,131	580,381	46,187	87,124	107,347	26,014
11	Apr-09	SD-30	572,625	95,765	200,432	660,257	56,428	98,384	114,172	22,042
12	May-09	SD-30	797,669	92,837	207,427	743,909	60,031	102,732	124,188	28,869
13	Jun-09	SD-30	985,778	84,940	205,070	757,207	68,852	100,680	119,868	28,921
14	Jul-09	SD-30	949,479	75,896	217,566	801,687	64,503	99,737	121,145	29,075
15	Aug-09	SD-30	987,789	82,121	244,672	863,190	64,703	100,952	120,016	29,410
16	Sep-09	SD-30	865,301	99,100	240,122	869,454	62,171	98,882	118,614	29,235
17										
18	Non-Coincident Peak (kW)									
19	Oct-08	SD-30	824,475	98,318	214,806	764,444	59,869	108,396	126,283	35,217
20	Nov-08	SD-30	587,383	90,081	187,056	696,546	57,519	99,054	120,279	45,412
21	Dec-08	SD-30	820,849	96,152	173,001	647,019	51,243	97,242	120,034	31,908
22	Jan-09	SD-30	744,569	81,139	148,670	614,353	48,441	93,018	118,066	32,196
23	Feb-09	SD-30	582,298	86,481	183,364	610,108	53,082	97,937	116,372	29,772
24	Mar-09	SD-30	642,352	83,010	164,513	660,402	52,257	96,318	117,346	29,766
25	Apr-09	SD-30	713,733	98,017	210,515	681,324	57,624	103,477	121,669	30,892
26	May-09	SD-30	921,022	92,837	224,752	781,556	61,574	106,153	124,299	32,015
27	Jun-09	SD-30	1,121,800	88,325	213,111	817,376	68,852	107,642	124,095	51,459
28	Jul-09	SD-30	1,049,605	79,754	227,155	856,526	70,815	110,081	124,820	33,668
29	Aug-09	SD-30	1,194,076	86,633	250,028	909,375	68,082	109,925	123,168	33,430
30	Sep-09	SD-30	995,358	99,100	257,114	901,475	62,330	105,731	120,332	35,517
31										
32	Coincident Peak @ ERCOT Peak									
33	Jun-09	SD-30	923,037	85,865	209,478	759,072	65,535	103,123	121,037	30,187
34	Jul-09	SD-30	894,245	73,409	214,780	828,369	65,990	100,003	119,782	27,471
35	Aug-09	SD-30	924,093	81,523	242,414	833,147	63,476	103,299	119,820	28,488
36	Sep-09	SD-30	805,087	97,616	257,114	892,655	61,859	101,451	119,356	29,869
37										
38	Energy @ Gen (kWh)									
39	Oct-08	SD-30	307,370,188	33,586,352	85,109,147	369,588,749	35,381,857	67,816,457	87,493,468	23,097,407
40	Nov-08	SD-30	247,344,362	31,079,428	71,042,266	312,236,095	31,154,022	61,833,765	81,331,319	23,184,670
41	Dec-08	SD-30	286,750,943	35,601,154	85,067,482	346,190,302	31,077,361	62,683,200	82,834,202	19,087,427
42	Jan-09	SD-30	301,784,066	35,459,385	79,319,744	340,563,958	29,972,570	62,476,682	81,771,027	17,419,008
43	Feb-09	SD-30	217,794,271	30,127,168	70,671,135	289,058,785	27,787,378	57,394,080	73,585,942	18,349,949
44	Mar-09	SD-30	259,953,993	33,156,074	72,397,327	324,767,296	32,071,564	64,409,019	81,786,102	20,332,687
45	Apr-09	SD-30	254,363,327	32,212,930	76,617,158	321,503,283	32,364,092	63,759,950	80,082,566	20,137,839
46	May-09	SD-30	370,571,311	33,027,735	90,996,880	362,050,628	36,843,676	69,435,447	85,905,577	21,395,102

Work Paper 21 - Demand and Energy

Purpose: Demand and Energy Data for Development of Production Related Allocation Factors

Line No.	Allocation Factor	Source Reference	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW	Primary Voltage ≥ 20 MW	Transmission Voltage
A	B	C	D	E	F	G	H	I	J	K
47	Jun-09	SD-30	471,019,567	33,250,178	95,906,141	387,172,314	39,361,712	69,819,712	84,784,347	21,768,164
48	Jul-09	SD-30	487,711,315	32,787,795	108,122,244	443,707,664	43,766,140	72,918,794	88,335,114	22,475,572
49	Aug-09	SD-30	524,149,759	34,370,674	111,967,308	454,010,844	41,882,880	72,779,652	87,851,510	22,388,123
50	Sep-09	SD-30	341,166,379	34,382,238	92,328,266	412,137,266	36,193,665	67,087,719	80,909,777	21,999,463
51										
52	Retail Energy @ Meter (kWh)									
53	Oct-08	SD-31	330,885,840	31,120,185	84,990,033	359,260,657	37,260,792	65,399,481	81,484,935	21,250,813
54	Nov-08	SD-31	224,996,680	26,163,797	72,797,447	311,837,166	32,655,817	59,539,569	76,417,267	20,795,640
55	Dec-08	SD-31	241,437,435	28,849,984	74,625,870	318,485,895	30,990,104	64,432,795	87,073,197	24,402,891
56	Jan-09	SD-31	299,713,505	33,740,996	81,210,072	337,504,084	32,984,734	65,353,856	87,332,469	18,865,628
57	Feb-09	SD-31	234,147,138	28,270,392	69,074,771	288,618,557	28,138,284	56,185,921	72,437,796	16,640,339
58	Mar-09	SD-31	216,162,072	27,665,862	69,248,614	297,930,440	27,273,399	58,857,457	72,599,770	19,171,906
59	Apr-09	SD-31	220,657,786	28,533,276	72,830,619	307,888,899	28,999,747	60,614,438	76,882,972	19,459,611
60	May-09	SD-31	264,356,501	30,438,596	76,573,671	322,562,699	30,538,134	61,461,390	75,901,429	19,655,704
61	Jun-09	SD-31	373,465,099	33,775,095	90,143,355	378,047,608	35,445,197	69,659,251	85,982,115	21,658,897
62	Jul-09	SD-31	508,713,520	38,224,740	102,032,683	418,974,555	41,044,834	69,403,218	83,938,112	22,252,912
63	Aug-09	SD-31	495,162,736	36,407,638	97,329,680	400,284,243	41,046,229	69,524,123	87,413,192	22,016,570
64	Sep-09	SD-31	454,703,058	35,694,645	96,179,979	401,214,205	39,570,355	69,398,466	80,801,694	21,448,771
65										
66	Sum of Maximum Demands (kW-months)									
67	Oct-08	SD-31	2,247,033	95,838	246,075	879,374	83,619	102,559	125,982	38,192
68	Nov-08	SD-31	1,755,273	94,441	229,910	835,091	77,560	97,080	123,485	34,295
69	Dec-08	SD-31	1,707,667	103,446	234,425	824,785	71,874	100,591	119,512	37,051
70	Jan-09	SD-31	2,098,480	92,874	250,769	831,811	72,487	95,177	116,963	33,451
71	Feb-09	SD-31	2,004,503	96,914	225,751	815,832	70,224	93,735	113,831	30,989
72	Mar-09	SD-31	1,683,566	86,226	225,165	818,994	69,036	97,324	114,198	31,413
73	Apr-09	SD-31	1,606,538	103,952	234,865	812,162	71,297	96,738	114,828	30,924
74	May-09	SD-31	1,412,972	96,339	243,312	841,829	74,252	101,150	118,838	32,395
75	Jun-09	SD-31	1,625,668	103,126	267,471	896,381	81,037	102,483	121,026	32,702
76	Jul-09	SD-31	2,004,622	88,579	286,839	944,112	87,414	103,833	121,181	36,915
77	Aug-09	SD-31	1,977,260	91,074	280,534	937,559	87,679	102,592	121,656	33,853
78	Sep-09	SD-31	2,545,168	102,522	275,187	932,421	88,637	102,184	120,034	36,442
79										
80	**Demand and Energy Allocation Factors**									
81										
82	4CP		3,788,346	342,057	907,429	3,291,538	260,228	400,252	479,642	116,642
83										
84	12CP		8,683,373	1,016,598	2,313,273	8,453,769	681,613	1,153,425	1,401,636	335,710
85										
86	4CP @ ERCOT Peak		3,546,463	338,413	923,786	3,313,242	256,860	407,876	479,994	116,014
87										
88	1NCP		1,194,076	99,100	257,114	909,375	70,815	110,081	126,283	51,459
89										
90	12NCP		10,197,519	1,079,846	2,454,085	8,940,505	711,688	1,234,975	1,456,762	421,250
91										
92	Sum of Maximum Demands		22,668,750	1,155,332	3,000,305	10,370,350	935,115	1,195,446	1,431,533	408,622

Work Paper 21 - Demand and Energy

Purpose: Demand and Energy Data for Development of Production Related Allocation Factors

Line No.	Allocation Factor	Source Reference	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW	Primary Voltage ≥ 20 MW	Transmission Voltage
A	B	C	D	E	F	G	H	I	J	K
93										
94	Average Demand		464,610	45,553	118,670	498,058	47,701	90,458	113,775	28,726
95										
96	Class Excess Demand (net of standby contribution)		729,467	53,547	138,444	411,317	23,014	19,623	12,507	462
97										
98	System Coincident Peak									
99										
100	System Average Demand									
101										
102	System Excess Demand									
103										
104	Excess Allocation Factor		0.521	0.038	0.099	0.294	0.016	0.014	0.009	0.000
105										
106	Allocated Excess Demand		562,149	41,265	106,689	316,974	17,735	15,122	9,639	356
107										
108	Total Average and Excess		1,026,759	86,818	225,359	815,032	65,436	105,581	123,414	29,082
109										
110	Average and Excess Factor		0.412	0.035	0.090	0.327	0.026	0.042	0.049	0.012
111										
112	Net Energy for Load (NEFL)		4,069,979,479	399,041,111	1,039,545,098	4,362,987,184	417,856,916	792,414,476	996,670,950	251,635,412
113										
114	kWh Sold		3,864,401,370	378,885,207	987,036,795	4,142,609,008	405,947,626	769,829,965	968,264,949	247,619,682
115										
116	Sum of Maximum Demands for Summer (June - Sept)		8,152,718	385,302	1,110,031	3,710,473	344,768	411,092	483,896	139,911
117										
118	kWh Sold During Summer Months (June - Sept)		1,832,044,412	144,102,118	385,685,698	1,598,520,610	157,106,615	277,985,057	338,135,114	87,377,150
119										
120	Number of Customers (Cust-Mo.)	WP 22	4,374,252	384,008	124,321	38,566	1,224	240	48	48
121										
122	Green Choice kWh Sold	WP 44.1	54,762,351	9,269,558	27,628,167	152,058,278	8,933,972	-	-	-
123										
124	Green Choice NEFL	WP 44.1	57,675,594	9,762,679	29,097,928	160,147,462	9,196,068	-	-	-
125										
126	Green Choice kWh Sold During Summer Mo	SD-31	26,361,720	3,788,110	11,474,208	62,231,426	3,203,922	-	-	-
127										
128	kWh Sold Net of Green Choice		3,809,639,019	369,615,649	959,408,628	3,990,550,730	397,013,654	769,829,965	968,264,949	247,619,682
129										
130	NEFL Net of Green Choice		4,012,303,885	389,278,432	1,010,447,170	4,202,839,722	408,660,848	792,414,476	996,670,950	251,635,412
131										
132	Summer kWh Sold Net of Green Choice		1,805,682,692	140,314,009	374,211,490	1,536,289,184	153,902,693	277,985,057	338,135,114	87,377,150
133										
134	Standby Contribution to Excess Demand	SD-30	-	-	-	-	101	-	-	22,271

Work Paper 21 - Demand and Energy

Line No.	Allocation Factor	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A	B	L	M	N	O	P
1						
2	**Normalized Load Research Data**					
3						
4	Coincident Peak (kW)					
5	Oct-08	82	-	4	292	2,097,000
6	Nov-08	87	-	4	274	1,692,200
7	Dec-08	90	-	4	912	1,832,300
8	Jan-09	8,013	2,335	334	186	1,726,100
9	Feb-09	93	-	4	657	1,577,500
10	Mar-09	89	-	5	740	1,564,600
11	Apr-09	92	-	5	299	1,820,500
12	May-09	92	-	5	441	2,158,200
13	Jun-09	93	-	6	286	2,351,700
14	Jul-09	88	-	6	318	2,359,500
15	Aug-09	90	-	6	451	2,493,400
16	Sep-09	87	-	5	529	2,383,500
17						
18	Non-Coincident Peak (kW)					
19	Oct-08	8,688	2,883	473	4,187	2,248,038
20	Nov-08	8,948	2,811	421	3,685	1,899,195
21	Dec-08	9,340	2,748	419	1,699	2,051,653
22	Jan-09	9,164	2,688	382	2,176	1,894,860
23	Feb-09	8,936	3,157	371	3,803	1,775,680
24	Mar-09	9,375	3,330	487	3,936	1,863,091
25	Apr-09	9,263	3,710	473	3,498	2,034,196
26	May-09	9,470	4,268	552	1,916	2,360,413
27	Jun-09	9,246	4,595	616	2,291	2,609,408
28	Jul-09	8,766	4,344	643	1,977	2,568,154
29	Aug-09	8,945	4,127	633	3,605	2,792,029
30	Sep-09	8,604	3,610	596	3,693	2,593,459
31						
32	Coincident Peak @ ERCOT Peak					
33	Jun-09	91	-	6	409	2,297,840
34	Jul-09	87	-	6	286	2,324,430
35	Aug-09	88	-	6	315	2,396,670
36	Sep-09	86	-	5	434	2,365,530
37						
38	Energy @ Gen (kWh)					
39	Oct-08	3,040,728	998,906	165,471	502,087	1,014,150,817
40	Nov-08	3,243,637	1,010,178	152,600	390,546	864,002,889
41	Dec-08	3,606,822	1,053,052	161,634	241,239	954,354,817
42	Jan-09	3,486,677	1,007,835	145,185	246,011	953,652,145
43	Feb-09	2,799,797	977,209	116,228	349,877	789,011,819
44	Mar-09	2,994,542	1,050,999	155,616	572,378	893,647,597
45	Apr-09	2,613,807	1,031,020	133,597	386,703	885,206,272
46	May-09	2,336,423	1,032,369	136,079	321,939	1,074,053,165

Work Paper 21 - Demand and Energy

Line No.	Allocation Factor	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A	B	L	M	N	O	P
47	Jun-09	2,151,486	1,046,175	143,216	404,888	1,206,827,901
48	Jul-09	2,113,283	1,003,150	154,962	405,708	1,303,501,741
49	Aug-09	2,421,341	1,021,171	171,362	362,788	1,353,377,411
50	Sep-09	2,592,179	947,784	160,811	407,591	1,090,313,136
51						
52	Retail Energy @ Meter (kWh)					
53	Oct-08	2,202,731	989,593	142,167	368,604	1,015,355,832
54	Nov-08	2,526,996	970,172	142,167	356,439	829,199,159
55	Dec-08	2,646,248	968,522	142,167	347,957	874,403,066
56	Jan-09	2,837,752	973,578	142,167	301,325	960,960,166
57	Feb-09	2,846,011	969,586	142,167	348,345	797,819,309
58	Mar-09	2,300,341	954,062	142,167	424,117	792,730,208
59	Apr-09	2,336,678	963,347	142,167	423,720	819,733,261
60	May-09	2,065,924	963,467	142,167	344,705	885,004,386
61	Jun-09	1,824,190	952,345	142,167	342,531	1,091,437,849
62	Jul-09	1,668,786	955,292	142,167	336,121	1,287,686,940
63	Aug-09	1,724,641	956,108	142,167	363,401	1,252,370,728
64	Sep-09	6,733,321	948,563	142,167	402,555	1,207,237,779
65						
66	Sum of Maximum Demands (kW-months)					
67	Oct-08	8,621	3,873	556	1,443	3,833,167
68	Nov-08	9,890	3,797	556	1,395	3,262,774
69	Dec-08	10,357	3,791	556	1,362	3,215,417
70	Jan-09	11,107	3,810	556	1,179	3,608,665
71	Feb-09	11,139	3,795	556	1,363	3,468,631
72	Mar-09	9,003	3,734	556	1,660	3,140,876
73	Apr-09	9,146	3,770	556	1,658	3,086,436
74	May-09	8,086	3,771	556	1,349	2,934,850
75	Jun-09	7,140	3,727	556	1,341	3,242,657
76	Jul-09	6,531	3,739	556	1,316	3,685,638
77	Aug-09	6,750	3,742	556	1,422	3,644,678
78	Sep-09	26,354	3,713	556	1,576	4,234,794
79						
80	**Demand and Energy Allocation Factors**					
81						
82	4CP	358	-	24	1,583	9,588,100
83						
84	12CP	8,995	2,335	389	5,384	24,056,500
85						
86	4CP @ ERCOT Peak	353	-	24	1,445	9,384,470
87						
88	1NCP	9,470	4,595	643	4,187	2,837,197
89						
90	12NCP	108,745	42,272	6,065	36,466	26,690,177
91						
92	Sum of Maximum Demands	124,124	45,263	6,677	17,064	41,358,581

Work Paper 21 - Demand and Energy

Line No.	Allocation Factor	Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A	B	L	M	N	O	P
93						
94	Average Demand	3,813	1,390	205	524	1,413,482
95						
96	Class Excess Demand (net of standby contrib	5,657	3,205	438	3,662	1,401,344
97						
98	System Coincident Peak					2,493,400
99						
100	System Average Demand					1,413,482
101						
102	System Excess Demand					1,079,918
103						
104	Excess Allocation Factor	0.004	0.002	0.000	0.003	1.000
105						
106	Allocated Excess Demand	4,359	2,470	337	2,822	1,079,918
107						
108	Total Average and Excess	8,172	3,860	543	3,347	2,493,400
109						
110	Average and Excess Factor	0.003	0.002	0.000	0.001	1.000
111						
112	Net Energy for Load (NEFL)	33,400,720	12,179,848	1,796,760	4,591,753	12,382,099,708
113						
114	kWh Sold	31,713,621	11,564,634	1,706,004	4,359,820	11,813,938,683
115						
116	Sum of Maximum Demands for Summer (Jur	46,775	14,921	2,226	5,654	14,807,767
117						
118	kWh Sold During Summer Months (June - Se	11,950,939	3,812,307	568,668	1,444,608	4,838,733,296
119						
120	Number of Customers (Cust-Mo.)	48	-	12	473	4,923,240
121						
122	Green Choice kWh Sold	-	-	-	28,192	252,680,519
123						
124	Green Choice NEFL	-	-	-	29,692	265,909,424
125						
126	Green Choice kWh Sold During Summer Moı	-	-	-	-	107,059,386
127						
128	kWh Sold Net of Green Choice	31,713,621	11,564,634	1,706,004	4,331,628	11,561,258,164
129						
130	NEFL Net of Green Choice	33,400,720	12,179,848	1,796,760	4,562,062	12,116,190,284
131						
132	Summer kWh Sold Net of Green Choice	11,950,939	3,812,307	568,668	1,444,608	4,731,673,910
133						
134	Standby Contribution to Excess Demand	-	-	-	-	22,371

Work Paper 22 - Customer Allocation

Purpose: Customer Count Data for Development of Allocation Factors for Customer Related Costs

Line No.		Source Reference	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW	Primary Voltage ≥ 20 MW	Transmission Voltage
A		B	C	D	E	F	G	H	I	J
1										
2	Number of Customers (Cust-Mo.)	SD-31	4,374,252	384,008	124,321	38,566	1,224	240	48	48
3										
4										
5	**Number of Customer Months by Service Type (Proposed Customer Classes)**									
6	FY 2009 AE Customer Classes:									
7	Residential	SD-31	4,374,252	1,243	5,375	810	-	-	-	-
8	General Service - Non-Demand	SD-31	-	375,408	24,252	-	-	-	-	-
9	Water and Wastewater	SD-31	-	822	717	405	192	-	-	-
10	Other City	SD-31	-	4,605	2,229	1,314	168	-	-	-
11	Street Lighting and Traffic Signals	SD-31	-	-	-	-	-	-	-	-
12	General Service - Demand (Med)	SD-31	-	-	89,527	31,025	-	-	-	-
13	General Service - Demand (Large)	SD-31	-	-	-	-	-	-	-	-
14	Primary Service	SD-31	-	-	-	84	636	-	-	-
15	School General Service - Demand	SD-31	-	-	144	-	-	-	-	-
16	Transmission Service	SD-31	-	-	-	-	-	-	-	24
17	University of Texas	SD-31	-	-	-	-	60	-	-	12
18	State General Service Non-Demand	SD-31	-	1,930	417	-	-	-	-	-
19	State General Service - Demand	SD-31	-	-	933	1,995	12	-	-	-
20	State Large Primary Service	SD-31	-	-	-	-	24	12	-	-
21	State Large Primary Service TOU	SD-31	-	-	-	-	-	24	-	-
22	State Primary Service	SD-31	-	-	-	-	72	-	-	-
23	Security Lighting / Outdoor Lighting	SD-31	-	-	-	-	-	-	-	-
24	Independent School Districts TOU	SD-31	-	-	727	2,321	-	-	-	-
25	LIR1/LIR1S	SD-31	-	-	-	216	-	24	-	-
26	LIR2/LIR3	SD-31	-	-	-	24	24	72	48	12
27	LTC1S	SD-31	-	-	-	12	-	-	-	-
28	LTC2/LTC3	SD-31	-	-	-	360	36	108	-	-
29			4,374,252	384,008	124,321	38,566	1,224	240	48	48
30										
31	**Secondary Service less than 50 KW [1, 2]**		**4,374,252**	**376,651**	**119,154**	**-**	**-**	**-**	**-**	**-**
32										
33	**Street Lighting**									
34	Number of Bulbs [3]	SD-58	-	-	-	-	-	-	-	-
35										
36	**Security Lighting**									
37	Number of Bulbs [4]	SD-59	-	-	-	-	-	-	-	-
38										
39	**City-Owned Lighting**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
40										
41		Notes:								
42			[1] Excluding Street Lighting, State, City and School Accounts							
43			[2] Used for Uncollectible Account Development							
44			[3] As of December 2010							
45			[4] As of September 2009							

Work Paper 22 - Customer Allocation

Line No.		Service Area Street Lighting	AE-Owned Private Outdoor Lighting	Non-Metered Lighting	Metered Lighting	Total
A		K	L	M	N	O
1						
2	Number of Customers (Cust-Mo.)	48	-	12	473	4,923,240
3						
4						
5	**Number of Customer Months by Servic**					
6	FY 2009 AE Customer Classes:					
7	Residential	-	-	-	-	4,381,680
8	General Service - Non-Demand	-	-	-	432	400,092
9	Water and Wastewater	-	-	-	-	2,136
10	Other City	-	-	-	-	8,316
11	Street Lighting and Traffic Signals	48	-	12	-	60
12	General Service - Demand (Med)	-	-	-	-	120,552
13	General Service - Demand (Large)	-	-	-	-	-
14	Primary Service	-	-	-	-	720
15	School General Service - Demand	-	-	-	-	144
16	Transmission Service	-	-	-	-	24
17	University of Texas	-	-	-	-	72
18	State General Service Non-Demand	-	-	-	41	2,388
19	State General Service - Demand	-	-	-	-	2,940
20	State Large Primary Service	-	-	-	-	36
21	State Large Primary Service TOU	-	-	-	-	24
22	State Primary Service	-	-	-	-	72
23	Security Lighting / Outdoor Lighting	-	-	-	-	-
24	Independent School Districts TOU	-	-	-	-	3,048
25	LIR1/LIR1S	-	-	-	-	240
26	LIR2/LIR3	-	-	-	-	180
27	LTC1S	-	-	-	-	12
28	LTC2/LTC3	-	-	-	-	504
29		48	-	12	473	4,923,240
30						
31	**Secondary Service less than 50 KW [1, 2]**	**-**	**-**	**-**	**-**	**4,870,058**
32						
33	**Street Lighting**					
34	Number of Bulbs [3]	43,431	-	-	-	43,431
35						
36	**Security Lighting**					
37	Number of Bulbs [4]	-	15,190	-	-	15,190
38						
39	**City-Owned Lighting**	**43,431**	**15,190**	**-**	**-**	**58,621**
40						
41						
42						
43						
44						
45						

Work Paper 23 - Line Loss

Purpose: Calculation of Allocated Line and Transformer Losses

Line No.		Energy Sales Source Reference	Normalized Energy Sales @ Meter (kWh)	Losses	Normalized Energy Sales @ Generation (kWh)	Sales at Meter	Secondary Losses	Sales Plus Secondary Losses	Primary Losses
A		B	C	D	E	F	G	H	I
1									
2	Residential	WP 21	3,864,401,370	5.05%	4,069,979,479	3,864,401,370	89,580,107	3,953,981,478	51,047,140
3	Secondary Voltage < 10 kW	WP 21	378,885,207	5.05%	399,041,111	378,885,207	8,782,881	387,668,088	5,004,917
4	Secondary Voltage 10 - 49.9 kW	WP 21	987,036,795	5.05%	1,039,545,098	987,036,795	22,880,352	1,009,917,147	13,038,347
5	Secondary Voltage ≥ 50 kW	WP 21	4,142,609,008	5.05%	4,362,987,184	4,142,609,008	96,029,197	4,238,638,205	54,722,148
6	Primary Voltage < 3 MW	WP 21	405,947,626	2.85%	417,856,916	405,947,626	-	405,947,626	5,240,911
7	Primary Voltage 3 - 19.9 MW	WP 21	769,829,965	2.85%	792,414,476	769,829,965	-	769,829,965	9,938,746
8	Primary Voltage ≥ 20 MW	WP 21	968,264,949	2.85%	996,670,950	968,264,949	-	968,264,949	12,500,604
9	Transmission Voltage	WP 21	247,619,682	1.60%	251,635,412	247,619,682	-	247,619,682	-
10	Service Area Street Lighting	WP 21	31,713,621	5.05%	33,400,720	31,713,621	735,149	32,448,770	418,924
11	AE-Owned Private Outdoor Lighting	WP 21	11,564,634	5.05%	12,179,848	11,564,634	268,078	11,832,712	152,764
12	Non-Metered Lighting	WP 21	1,706,004	5.05%	1,796,760	1,706,004	39,547	1,745,551	22,536
13	Metered Lighting	WP 21	4,359,820	5.05%	4,591,753	4,359,820	101,064	4,460,884	57,591
14	Total		11,813,938,683		12,382,099,708	11,813,938,683	218,416,374	12,032,355,057	152,144,627
15									
16									
17	**Losses by Service Type**								
18	Secondary	WP 23.1	38.44%	218,416,374					
19	Primary	WP 23.1	26.78%	152,144,627					
20	Transmission	WP 23.1	34.78%	197,600,024					
21	Total	WP 23.1	100.00%	568,161,025					
22									

Work Paper 23 - Line Loss

Line No.		Sales Plus Primary & Secondary Losses	Transmission Losses	Sales Plus Transmission, Primary & Secondary Losses	Total Losses (kWh)	Total Losses (%)
A		J	K	L	M	N
1						
2	Residential	4,005,028,618	64,950,861	4,069,979,479	205,578,109	5.05%
3	Secondary Voltage < 10 kW	392,673,004	6,368,107	399,041,111	20,155,904	5.05%
4	Secondary Voltage 10 - 49.9 kW	1,022,955,494	16,589,604	1,039,545,098	52,508,303	5.05%
5	Secondary Voltage ≥ 50 kW	4,293,360,353	69,626,832	4,362,987,184	220,378,176	5.05%
6	Primary Voltage < 3 MW	411,188,537	6,668,379	417,856,916	11,909,290	2.85%
7	Primary Voltage 3 - 19.9 MW	779,768,711	12,645,765	792,414,476	22,584,511	2.85%
8	Primary Voltage ≥ 20 MW	980,765,553	15,905,396	996,670,950	28,406,000	2.85%
9	Transmission Voltage	247,619,682	4,015,730	251,635,412	4,015,730	1.60%
10	Service Area Street Lighting	32,867,693	533,026	33,400,720	1,687,099	5.05%
11	AE-Owned Private Outdoor Lighting	11,985,476	194,372	12,179,848	615,214	5.05%
12	Non-Metered Lighting	1,768,087	28,674	1,796,760	90,756	5.05%
13	Metered Lighting	4,518,476	73,278	4,591,753	231,933	5.05%
14	Total	12,184,499,684	197,600,024	12,382,099,708	568,161,025	4.59%
15						
16						
17	**Losses by Service Type**					
18	Secondary					
19	Primary					
20	Transmission					
21	Total					
22						

Work Paper 23.1 - Line Loss

Purpose: Identifies the Results of Transmission and Distribution Line Loss Study for Incorporation into the Cost of Service Analysis

Line No.						
A	B	C	D	E	F	G
1	**Source Reference: SD-32**					
2		**Actual**	**Normalized**			
3	2009 Annual Net-to-System Energy (MWh)	12,659,087	12,382,100			
4	2009 Annual Energy Sales (MWh)	12,076,915	11,813,939			
5	**ANNUAL SYSTEM LOSSES (MWh)**	**582,172**	**568,161**			
6	**PERCENT SYSTEM LOSSES**	**4.60%**	**4.59%**			
7						
8						
9	**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**
10						
11	**Voltage Level: Transmission 345 kV**	15,439	**0.12%**	2.65%	5.37	3.48%
12						
13	Transmission Line Losses	15,439	**0.12%**	2.65%	5.37	3.48%
14						
15	Transmission Substation Transformer Losses					
16	Core	0	**0.00%**	0.00%	0.00	0.00%
17	Winding	0	**0.00%**	0.00%	0.00	0.00%
18						
19	**Voltage Level: Transmission 138 kV**	181,956	**1.44%**	31.25%	60.22	39.04%
20						
21	Transmission Line Losses	153,844	**1.22%**	26.43%	53.51	34.69%
22						
23	Transmission Substation Transformer Losses					
24	Core	13,133	**0.10%**	2.26%	1.50	0.97%
25	Winding	14,979	**0.12%**	2.57%	5.21	3.38%
26						
27	**Voltage Level: Transmission 69 kV**	5,078	**0.04%**	0.87%	1.36	0.88%
28						
29	Transmission Line Losses	2,875	**0.02%**	0.49%	1.00	0.65%
30						
31	Transmission Substation Transformer Losses					
32	Core	1,743	**0.01%**	0.30%	0.20	0.13%
33	Winding	460	**0.00%**	0.08%	0.16	0.10%
34						
35	**Voltage Level: Distribution**	155,897	**1.23%**	26.78%	48.87	31.68%
36						
37	Distribution Line Losses	104,037	**0.82%**	17.87%	36.19	23.46%
38						
39	Distribution Substation Transformer Losses					
40	Core	22,893	**0.18%**	3.93%	2.61	1.69%
41	Winding	28,967	**0.23%**	4.98%	10.08	6.53%
42						
43	**Voltage Level: Secondary**	208,178	**1.64%**	35.76%	38.44	24.92%
44						
45	Distribution Transformer Losses					
46	Core	139,886	**1.11%**	24.03%	15.97	10.35%
47	Winding	21,803	**0.17%**	3.75%	7.58	4.92%
48						
49	Service and Secondary Line Losses	42,789	**0.34%**	7.35%	14.89	9.65%
50						
51	Street & Security Lights[1, 3]	3,700	**0.03%**	0.64%	0.00	0.00%
52						
53	Unmetered Loads, Loose Hardware, Corona or Other	15,625	**0.12%**	2.68%	0.00	0.00%
54	Mechanical Abnormalities and Metering Inaccuracies					
55						
56	TOTALS	582,172	**4.60%**	100.00%	154.26	100.00%
57						
58						

Work Paper 23.1 - Line Loss

Purpose: Identifies the Results of Transmission and Distribution Line Loss Study for Incorporation into the Cost of Service Analysis

Line No. A	B	C	D	E	F	G
59	Notes:					
60	[1] Street and Security Light losses are the difference in billed kWh and total kWh for all lights					
61	[2] Annual Energy Losses were determined using the following equations:					
62	Annual Energy Losses = Peak Demand (kW) * Time (hrs) * Loss Factor					
63	Loss Factor = k * Load Factor + (1 - k) * (Load Factor)^2					
64	"k" constant	0.08				
65	Load Factor	55.54%				
66	[3] Street and Security Light were off at the recorded peak					
67	[4]he high side voltage, all other transformer results are categorized by low side voltage					

Work Paper 24 - Production Non-Fuel O&M

Purpose: Develop Allocators to Sub-Functionalize Major Generating Facilities within the Production Function

Line No.		FERC Account	Source Reference	FY 2009 (before adjustments) Misc	Misc	Sand Hill	Decker	Domain	RMEC
A		B	C	D	E	F	G	H	I
1	Steam Generation Oper Superv And Engineering	500	SD-8	$ 4,047,965	-	$ 719,337	-	-	-
2	Steam Generation - Fuel	501	SD-8	268,983	(311,818)	-	-	-	-
3	Steam Expenses	502	SD-8	1,874,713	-	30,386	-	-	-
4	Electric Expenses	505	SD-8	-	-	30,163	-	-	-
5	Miscellaneous Steam Power	506	SD-8	641,091	-	225,344	-	-	-
6	Steam Rents	507	SD-8	(0)	-	146	-	-	-
7	Steam Maintenance Supervision	510	SD-8	2,034,554	-	21,823	-	-	-
8	Steam Maintenance Of Structures	511	SD-8	(60,817)	-	34,898	-	-	-
9	Steam Maintenance Of Boiler Plant	512	SD-8	2,635	-	555,089	-	-	-
10	Steam Maintenance Of Electric Plant	513	SD-8	914	-	1,631,583	-	-	-
11	Maintenance Of Misc Steam Plant	514	SD-8	137,431	-	203,718	-	-	-
12	Nuclear Operation Supervision	517	SD-8	-	-	-	-	-	-
13	Nuclear Fuel Expense	518	SD-8	-	-	-	-	-	-
14	Coolants And Water	519	SD-8	-	-	-	-	-	-
15	Nuclear Steam Expenses	520	SD-8	-	-	-	-	-	-
16	Nuclear Electric Expenses	523	SD-8	-	-	-	-	-	-
17	Misc Nuclear Power Expenses	524	SD-8	-	-	-	-	-	-
18	Nuclear Maintenance Supervision	528	SD-8	-	-	-	-	-	-
19	Nuclear Maintenance Of Structures	529	SD-8	-	-	-	-	-	-
20	Nuclear Maintenance Of Reactor Plant	530	SD-8	-	-	-	-	-	-
21	Nuclear Maintenance Of Electric Plant	531	SD-8	-	-	-	-	-	-
22	Maintenance Of Miscellaneous Nuclear Plant	532	SD-8	-	-	-	-	-	-
23	Other Power Generation Operation Supervision	546	SD-8	525	-	1,081,250	-	1,875	1,118,266
24	Other Power Generation Fuel Expense	547	SD-8	-	-	-	-	-	-
25	Other Power Generation Expenses	548	SD-8	278,211	-	1,984,961	-	-	330
26	Miscellaneous Other Power Generation Expenses	549	SD-8	-	-	18,689	-	-	39,114
27	Other Power Generation Rents	550	SD-8	189,600	-	-	-	-	15,445
28	Other Power Generation Maint Supv And Engineering	551	SD-8	21	-	21,694	-	-	-
29	Other Power Generation Maint Of Structures	552	SD-8	131	-	76,982	-	-	210
30	Other Power Generation Maint Of Generating & Elec Plant	553	SD-8	259	-	7,031,899	-	-	-
31	Maint Of Miscellaneous Other Power Generation Plant	554	SD-8	446,777	-	653,755	-	-	-
32	Purchased Power	555	SD-8	21,600	-	-	324,533	-	-
33	System Control And Load Dispatching	556	SD-8	1,096,547	636,086	-	-	-	-
34	Other Power Expenses	557	SD-8	461,942	-	-	-	-	-
35				$ 11,443,083	$ 324,269	$ 14,321,716	$ 324,533	$ 1,875	$ 1,173,365
36									
37									

Work Paper 24 - Production Non-Fuel O&M

Purpose: Develop Allocators to Sub-Functionalize Major Generating Facilities within the Production Function

Line		FY 2009 (before adjustments) continued					FY 2009 Major Generation Facilities (FERC 500 - 554)				
No.		Holly	Decker	STP	FPP	Total	Sand Hill	Decker	STP	FPP	Total
A		J	K	L	M	N	O	P	Q	R	S
1	Steam Generation Oper Superv And Engineering	$ 1,351,276	$ 1,318,260	-	$ 1,024,413	$ 8,461,250	$ 719,337	$ 1,318,260	$ -	$ 1,024,413	$ 3,062,009
2	Steam Generation - Fuel	394,399	-	-	-	351,564	-	-	-	-	-
3	Steam Expenses	31,195	985,766	-	5,053,464	7,975,525	30,386	985,766	-	5,053,464	6,069,616
4	Electric Expenses	-	24,507	-	1,083,918	1,138,588	30,163	24,507	-	1,083,918	1,138,588
5	Miscellaneous Steam Power	82,953	843,186	-	2,601,966	4,394,541	225,344	843,186	-	2,601,966	3,670,496
6	Steam Rents	-	-	-	-	146	146	-	-	-	146
7	Steam Maintenance Supervision	133,217	83,492	-	-	2,273,086	21,823	83,492	-	-	105,315
8	Steam Maintenance Of Structures	1,746	95,573	-	144,351	215,751	34,898	95,573	-	144,351	274,821
9	Steam Maintenance Of Boiler Plant	2,194	1,179,613	-	4,616,691	6,356,222	555,089	1,179,613	-	4,616,691	6,351,393
10	Steam Maintenance Of Electric Plant	18,333	387,145	-	1,496,298	3,534,272	1,631,583	387,145	-	1,496,298	3,515,025
11	Maintenance Of Misc Steam Plant	55,896	1,843,170	-	1,312,974	3,553,188	203,718	1,843,170	-	1,312,974	3,359,861
12	Nuclear Operation Supervision	-	-	9,211,756	-	9,211,756	-	-	9,211,756	-	9,211,756
13	Nuclear Fuel Expense	-	-	-	-	-	-	-	-	-	-
14	Coolants And Water	-	-	953,232	-	953,232	-	-	953,232	-	953,232
15	Nuclear Steam Expenses	-	-	1,458,922	-	1,458,922	-	-	1,458,922	-	1,458,922
16	Nuclear Electric Expenses	-	-	4,134,216	-	4,134,216	-	-	4,134,216	-	4,134,216
17	Misc Nuclear Power Expenses	-	-	12,914,335	-	12,914,335	-	-	12,914,335	-	12,914,335
18	Nuclear Maintenance Supervision	-	-	4,898,622	-	4,898,622	-	-	4,898,622	-	4,898,622
19	Nuclear Maintenance Of Structures	-	-	2,347,069	-	2,347,069	-	-	2,347,069	-	2,347,069
20	Nuclear Maintenance Of Reactor Plant	-	-	5,620,149	-	5,620,149	-	-	5,620,149	-	5,620,149
21	Nuclear Maintenance Of Electric Plant	-	-	2,852,587	-	2,852,587	-	-	2,852,587	-	2,852,587
22	Maintenance Of Miscellaneous Nuclear Plant	-	-	662,509	-	662,509	-	-	662,509	-	662,509
23	Other Power Generation Operation Supervision	-	154,577	-	-	2,356,493	1,081,250	154,577	-	-	1,235,827
24	Other Power Generation Fuel Expense	-	-	-	-	-	-	-	-	-	-
25	Other Power Generation Expenses	-	226,006	-	-	2,489,508	1,984,961	226,006	-	-	2,210,967
26	Miscellaneous Other Power Generation Expenses	-	72,664	-	-	130,467	18,689	72,664	-	-	91,353
27	Other Power Generation Rents	-	89	-	-	205,134	-	89	-	-	89
28	Other Power Generation Maint Supv And Engineering	-	901	-	-	22,617	21,694	901	-	-	22,595
29	Other Power Generation Maint Of Structures	-	28,298	-	-	105,620	76,982	28,298	-	-	105,279
30	Other Power Generation Maint Of Generating & Elec Plant	-	1,140,605	-	-	8,172,762	7,031,899	1,140,605	-	-	8,172,504
31	Maint Of Miscellaneous Other Power Generation Plant	-	68,599	-	-	1,169,131	653,755	68,599	-	-	722,354
32	Purchased Power	-	-	-	-	346,133	-	-	-	-	-
33	System Control And Load Dispatching	-	-	-	-	1,732,634	-	-	-	-	-
34	Other Power Expenses	-	-	-	-	461,942	-	-	-	-	-
35		$ 2,071,209	$ 8,452,448	$ 45,053,396	$ 17,334,075	$ 100,499,969	$ 14,321,716	$ 8,452,448	$ 45,053,396	$ 17,334,075	$ 85,161,635
36											
37											

Work Paper 24 - Production Non-Fuel O&M

Purpose: Develop Allocators to Sub-Functionalize Major Generating Facilities within the Production Function

Line		FERC Transition for SHEC	FY 2009 (After FERC Transition for SHEC)						Test Year Adjustments				
									WP 12	WP 13	WP 11	WP 11	
No.		Sand Hill	Sand Hill	Decker	STP	FPP	Total		Sand Hill	FPP	STP	FPP	Total
A		T	U	V	W	X	Y		Z	AA	AB	AC	AD
1	Steam Generation Oper Superv And Engineering	$ (719,337)	$ -	$ 1,318,260	$ -	$ 1,024,413	$ 2,342,672		$ -	$ -	$ -	$ (28,211)	$ (28,211)
2	Steam Generation - Fuel	-	-	-	-	-	-		-	-	-	-	-
3	Steam Expenses	(30,386)	-	985,766	-	5,053,464	6,039,230		-	2,433,504	-	(284,260)	2,149,245
4	Electric Expenses	(30,163)	-	24,507	-	1,083,918	1,108,425		-	-	-	-	-
5	Miscellaneous Steam Power	(225,344)	-	843,186	-	2,601,966	3,445,153		-	-	-	68,000	68,000
6	Steam Rents	(146)	-	-	-	-	-		-	-	-	-	-
7	Steam Maintenance Supervision	(21,823)	-	83,492	-	-	83,492		-	-	-	98,145	98,145
8	Steam Maintenance Of Structures	(34,898)	-	95,573	-	144,351	239,923		-	-	-	43,670	43,670
9	Steam Maintenance Of Boiler Plant	(555,089)	-	1,179,613	-	4,616,691	5,796,304		-	-	-	(25,300)	(25,300)
10	Steam Maintenance Of Electric Plant	(1,631,583)	-	387,145	-	1,496,298	1,883,442		-	-	-	1,113,366	1,113,366
11	Maintenance Of Misc Steam Plant	(203,718)	-	1,843,170	-	1,312,974	3,156,143		-	-	-	308,275	308,275
12	Nuclear Operation Supervision	-	-	-	9,211,756	-	9,211,756		-	-	(310,355)	-	(310,355)
13	Nuclear Fuel Expense	-	-	-	-	-	-		-	-	-	-	-
14	Coolants And Water	-	-	-	953,232	-	953,232		-	-	83,777	-	83,777
15	Nuclear Steam Expenses	-	-	-	1,458,922	-	1,458,922		-	-	501,905	-	501,905
16	Nuclear Electric Expenses	-	-	-	4,134,216	-	4,134,216		-	-	191,435	-	191,435
17	Misc Nuclear Power Expenses	-	-	-	12,914,335	-	12,914,335		-	-	189,331	-	189,331
18	Nuclear Maintenance Supervision	-	-	-	4,898,622	-	4,898,622		-	-	1,152,420	-	1,152,420
19	Nuclear Maintenance Of Structures	-	-	-	2,347,069	-	2,347,069		-	-	341,657	-	341,657
20	Nuclear Maintenance Of Reactor Plant	-	-	-	5,620,149	-	5,620,149		-	-	1,524,030	-	1,524,030
21	Nuclear Maintenance Of Electric Plant	-	-	-	2,852,587	-	2,852,587		-	-	713,296	-	713,296
22	Maintenance Of Miscellaneous Nuclear Plant	-	-	-	662,509	-	662,509		-	-	86,131	-	86,131
23	Other Power Generation Operation Supervision	719,337	1,800,586	154,577	-	-	1,955,163		-	-	-	-	-
24	Other Power Generation Fuel Expense	-	-	-	-	-	-		-	-	-	-	-
25	Other Power Generation Expenses	60,549	2,045,510	226,006	-	-	2,271,516		1,448,193	-	-	-	1,448,193
26	Miscellaneous Other Power Generation Expenses	225,344	244,033	72,664	-	-	316,697		-	-	-	-	-
27	Other Power Generation Rents	146	146	89	-	-	234		-	-	-	-	-
28	Other Power Generation Maint Supv And Engineering	21,823	43,517	901	-	-	44,418		-	-	-	-	-
29	Other Power Generation Maint Of Structures	34,898	111,880	28,298	-	-	140,177		-	-	-	-	-
30	Other Power Generation Maint Of Generating & Elec Plant	2,186,673	9,218,572	1,140,605	-	-	10,359,176		2,699,254	-	-	-	2,699,254
31	Maint Of Miscellaneous Other Power Generation Plant	203,718	857,473	68,599	-	-	926,072		-	-	-	-	-
32	Purchased Power	-	-	-	-	-	-		-	-	-	-	-
33	System Control And Load Dispatching	-	-	-	-	-	-		-	-	-	-	-
34	Other Power Expenses	-	-	-	-	-	-		-	-	-	-	-
35		$ 0	$ 14,321,716	$ 8,452,448	$ 45,053,396	$ 17,334,075	$ 85,161,635		$ 4,147,447	$ 2,433,504	$ 4,473,626	$ 1,293,685	$ 12,348,262
36													
37													

Work Paper 24 - Production Non-Fuel O&M

Purpose: Develop Allocators to Sub-Functionalize Major Generating Facilities within the Production Function

Line		Test Year Non-Fuel O&M					Steam Power Generation (FERC 500 - 515)			Steam Power Generation Sub-Functionalized		
No.		Sand Hill	Decker	STP	FPP	Total	Decker Intermediate Gas	FPP Base Load Coal	Total	Intermediate Gas	Base Load Coal	Total
A		AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO
1	Steam Generation Oper Superv And Engineering	$ -	$ 1,318,260	$ -	$ 996,202	$ 2,314,462	$ 1,318,260	$ 996,202	$ 2,314,462	$ 1,318,260	$ 996,202	$ 2,314,462
2	Steam Generation - Fuel	-	-	-	-	-	-	-	-	-	-	-
3	Steam Expenses	-	985,766	-	7,202,709	8,188,475	985,766	7,202,709	8,188,475	985,766	7,202,709	8,188,475
4	Electric Expenses	-	24,507	-	1,083,918	1,108,425	24,507	1,083,918	1,108,425	24,507	1,083,918	1,108,425
5	Miscellaneous Steam Power	-	843,186	-	2,669,966	3,513,152	843,186	2,669,966	3,513,152	843,186	2,669,966	3,513,152
6	Steam Rents	-	-	-	-	-	-	-	-	-	-	-
7	Steam Maintenance Supervision	-	83,492	-	98,145	181,637	83,492	98,145	181,637	83,492	98,145	181,637
8	Steam Maintenance Of Structures	-	95,573	-	188,021	283,593	95,573	188,021	283,593	95,573	188,021	283,593
9	Steam Maintenance Of Boiler Plant	-	1,179,613	-	4,591,391	5,771,003	1,179,613	4,591,391	5,771,003	1,179,613	4,591,391	5,771,003
10	Steam Maintenance Of Electric Plant	-	387,145	-	2,609,663	2,996,808	387,145	2,609,663	2,996,808	387,145	2,609,663	2,996,808
11	Maintenance Of Misc Steam Plant	-	1,843,170	-	1,621,249	3,464,419	1,843,170	1,621,249	3,464,419	1,843,170	1,621,249	3,464,419
12	Nuclear Operation Supervision	-	-	8,901,401	-	8,901,401	-	-	-	-	-	-
13	Nuclear Fuel Expense	-	-	-	-	-	-	-	-	-	-	-
14	Coolants And Water	-	-	1,037,009	-	1,037,009	-	-	-	-	-	-
15	Nuclear Steam Expenses	-	-	1,960,827	-	1,960,827	-	-	-	-	-	-
16	Nuclear Electric Expenses	-	-	4,325,651	-	4,325,651	-	-	-	-	-	-
17	Misc Nuclear Power Expenses	-	-	13,103,665	-	13,103,665	-	-	-	-	-	-
18	Nuclear Maintenance Supervision	-	-	6,051,042	-	6,051,042	-	-	-	-	-	-
19	Nuclear Maintenance Of Structures	-	-	2,688,726	-	2,688,726	-	-	-	-	-	-
20	Nuclear Maintenance Of Reactor Plant	-	-	7,144,179	-	7,144,179	-	-	-	-	-	-
21	Nuclear Maintenance Of Electric Plant	-	-	3,565,883	-	3,565,883	-	-	-	-	-	-
22	Maintenance Of Miscellaneous Nuclear Plant	-	-	748,640	-	748,640	-	-	-	-	-	-
23	Other Power Generation Operation Supervision	1,800,586	154,577	-	-	1,955,163	-	-	-	-	-	-
24	Other Power Generation Fuel Expense	-	-	-	-	-	-	-	-	-	-	-
25	Other Power Generation Expenses	3,493,703	226,006	-	-	3,719,709	-	-	-	-	-	-
26	Miscellaneous Other Power Generation Expenses	244,033	72,664	-	-	316,697	-	-	-	-	-	-
27	Other Power Generation Rents	146	89	-	-	234	-	-	-	-	-	-
28	Other Power Generation Maint Supv And Engineering	43,517	901	-	-	44,418	-	-	-	-	-	-
29	Other Power Generation Maint Of Structures	111,880	28,298	-	-	140,177	-	-	-	-	-	-
30	Other Power Generation Maint Of Generating & Elec Plant	11,917,826	1,140,605	-	-	13,058,431	-	-	-	-	-	-
31	Maint Of Miscellaneous Other Power Generation Plant	857,473	68,599	-	-	926,072	-	-	-	-	-	-
32	Purchased Power	-	-	-	-	-	-	-	-	-	-	-
33	System Control And Load Dispatching	-	-	-	-	-	-	-	-	-	-	-
34	Other Power Expenses	-	-	-	-	-	-	-	-	-	-	-
35		$ 18,469,164	$ 8,452,448	$ 49,527,022	$ 21,061,263	$ 97,509,898	$ 6,760,710	$ 21,061,263	$ 27,821,974	**$ 6,760,710**	**$ 21,061,263**	**$ 27,821,974**
36												
37										**24.3%**	**75.7%**	**100.0%**

Work Paper 24 - Production Non-Fuel O&M

Purpose: Develop Allocators to Sub-Functionalize Major Generating Facilities within the Production Function

Line No.		Facility	MWh Base	MWh Intermediate	MWh Peak	MWh Total	Other Power Generation (FERC 546 - 554) Sand Hill Intermediate Gas	Sand Hill Peak Gas	Decker Peak Gas	Total	Other Power Generation Sub-Functionalized Intermediate Gas	Peak Gas	Total
A		AP	AQ	AR	AS	AT	AU	AV	AW	AX	AY	AZ	BA
1	Steam Generation Oper Superv And Engineering	**Sand Hill Energy Center**	-	1,613,964	139,038	1,753,002	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Steam Generation - Fuel		**0.00%**	**92.07%**	**7.93%**	**100.00%**	-	-	-	-	-	-	-
3	Steam Expenses			Source Reference: WP 44 - PCR			-	-	-	-	-	-	-
4	Electric Expenses						-	-	-	-	-	-	-
5	Miscellaneous Steam Power						-	-	-	-	-	-	-
6	Steam Rents						-	-	-	-	-	-	-
7	Steam Maintenance Supervision						-	-	-	-	-	-	-
8	Steam Maintenance Of Structures						-	-	-	-	-	-	-
9	Steam Maintenance Of Boiler Plant						-	-	-	-	-	-	-
10	Steam Maintenance Of Electric Plant						-	-	-	-	-	-	-
11	Maintenance Of Misc Steam Plant						-	-	-	-	-	-	-
12	Nuclear Operation Supervision						-	-	-	-	-	-	-
13	Nuclear Fuel Expense						-	-	-	-	-	-	-
14	Coolants And Water						-	-	-	-	-	-	-
15	Nuclear Steam Expenses						-	-	-	-	-	-	-
16	Nuclear Electric Expenses						-	-	-	-	-	-	-
17	Misc Nuclear Power Expenses						-	-	-	-	-	-	-
18	Nuclear Maintenance Supervision						-	-	-	-	-	-	-
19	Nuclear Maintenance Of Structures						-	-	-	-	-	-	-
20	Nuclear Maintenance Of Reactor Plant						-	-	-	-	-	-	-
21	Nuclear Maintenance Of Electric Plant						-	-	-	-	-	-	-
22	Maintenance Of Miscellaneous Nuclear Plant						-	-	-	-	-	-	-
23	Other Power Generation Operation Supervision						1,657,774	142,812	154,577	1,955,163	1,657,774	297,389	1,955,163
24	Other Power Generation Fuel Expense						-	-	-	-	-	-	-
25	Other Power Generation Expenses						3,216,603	277,101	226,006	3,719,709	3,216,603	503,107	3,719,709
26	Miscellaneous Other Power Generation Expenses						224,678	19,355	72,664	316,697	224,678	92,019	316,697
27	Other Power Generation Rents						134	12	89	234	134	100	234
28	Other Power Generation Maint Supv And Engineering						40,065	3,451	901	44,418	40,065	4,353	44,418
29	Other Power Generation Maint Of Structures						103,006	8,874	28,298	140,177	103,006	37,171	140,177
30	Other Power Generation Maint Of Generating & Elec Plant						10,972,571	945,255	1,140,605	13,058,431	10,972,571	2,085,859	13,058,431
31	Maint Of Miscellaneous Other Power Generation Plant						789,463	68,010	68,599	926,072	789,463	136,609	926,072
32	Purchased Power						-	-	-	-	-	-	-
33	System Control And Load Dispatching						-	-	-	-	-	-	-
34	Other Power Expenses						-	-	-	-	-	-	-
35							**$ 17,004,294**	**$ 1,464,870**	**$ 1,691,738**	**$ 20,160,902**	**$ 17,004,294**	**$ 3,156,608**	**$ 20,160,902**
36													
37											**84.3%**	**15.7%**	**100.0%**

Work Paper 24 - Production Non-Fuel O&M
Purpose: Detail Holly O&M in FY 2009 for Removal from the Test Year

Line No.		FERC Account	Source Reference	Labor FY 2009 Actual	Non-Labor FY 2009 Actual	Labor Reimbursements Actual	Non-Labor Reimbursements Actual	Overhead Reimbursements Actual	Total FY 2009 Actual
A		B	C	D	F	G	H	I	J
1	**Holly Power Plant O&M**								
2	Steam Generation Oper Superv And Engineering	500	SD-66	$ 1,414,292	$ 41,667	$ (61,038)	$ (2,315)	$ (41,329)	$ 1,351,276
3	Steam Generation - Fuel	501	SD-66	387,892	6,506	-	-	-	394,399
4	Steam Expenses	502	SD-66	30,456	739	-	-	-	31,195
5	Electric Expenses	505	SD-66	-	-	-	-	-	-
6	Miscellaneous Steam Power	506	SD-66	44,191	45,825	(4,046)	(10)	(3,007)	82,953
7	Steam Rents	507	SD-66	-	-	-	-	-	-
8	Steam Maintenance Supervision	510	SD-66	124,225	8,992	-	-	-	133,217
9	Steam Maintenance Of Structures	511	SD-66	1,510	236	-	-	-	1,746
10	Steam Maintenance Of Boiler Plant	512	SD-66	-	2,194	-	-	-	2,194
11	Steam Maintenance Of Electric Plant	513	SD-66	-	18,333	-	-	-	18,333
12	Maintenance Of Misc Steam Plant	514	SD-66	-	55,896	-	-	-	55,896
13				$ 2,002,567	$ 180,388	$ (65,084)	$ (2,325)	$ (44,336)	$ 2,071,209

Work Paper 24 - Production Non-Fuel O&M
Purpose: Detail Holly O&M in FY 2009 for Removal from the Test Year

Line No.		FERC Account	Net Labor FY 2009 Actual	Net Non-Labor FY 2009 Actual	Overhead FY 2009 Actual	Total FY 2009 Actual	Test Year Labor	Test Year Non-Labor	Test Year Overhead
A		B	K	L	M	N	O	P	Q
1	**Holly Power Plant O&M**								
2	Steam Generation Oper Superv And Engineering	500	$ 1,353,253	$ 39,352	$ (41,329)	$ 1,351,276	$ -	$ -	$ (41,329)
3	Steam Generation - Fuel	501	387,892	6,506	-	394,399	-	-	-
4	Steam Expenses	502	30,456	739	-	31,195	-	-	-
5	Electric Expenses	505	-	-	-	-	-	-	-
6	Miscellaneous Steam Power	506	40,145	45,815	(3,007)	82,953	-	-	(3,007)
7	Steam Rents	507	-	-	-	-	-	-	-
8	Steam Maintenance Supervision	510	124,225	8,992	-	133,217	-	-	-
9	Steam Maintenance Of Structures	511	1,510	236	-	1,746	-	-	-
10	Steam Maintenance Of Boiler Plant	512	-	2,194	-	2,194	-	-	-
11	Steam Maintenance Of Electric Plant	513	-	18,333	-	18,333	-	-	-
12	Maintenance Of Misc Steam Plant	514	-	55,896	-	55,896	-	-	-
13			$ 1,937,482	$ 178,063	$ (44,336)	$ 2,071,209	$ -	$ -	$ (44,336)

Work Paper 24 - Production Non-Fuel O&M

Purpose: Detail Holly O&M in FY 2009 for Removal from the Test Year

Line No.		FERC Account	Test Year Total	Adjustment Labor	Adjustment Non-Labor	Adjustment Overhead	Adjustment Total
A		B	R	S	T	U	V
1	**Holly Power Plant O&M**						
2	Steam Generation Oper Superv And Engineering	500	$ (41,329)	$ (1,353,253)	$ (39,352)	$ -	$ (1,392,605)
3	Steam Generation - Fuel	501	-	(387,892)	(6,506)	-	(394,399)
4	Steam Expenses	502	-	(30,456)	(739)	-	(31,195)
5	Electric Expenses	505	-	-	-	-	-
6	Miscellaneous Steam Power	506	(3,007)	(40,145)	(45,815)	-	(85,960)
7	Steam Rents	507	-	-	-	-	-
8	Steam Maintenance Supervision	510	-	(124,225)	(8,992)	-	(133,217)
9	Steam Maintenance Of Structures	511	-	(1,510)	(236)	-	(1,746)
10	Steam Maintenance Of Boiler Plant	512	-	-	(2,194)	-	(2,194)
11	Steam Maintenance Of Electric Plant	513	-	-	(18,333)	-	(18,333)
12	Maintenance Of Misc Steam Plant	514	-	-	(55,896)	-	(55,896)
13			$ (44,336)	$ (1,937,482)	$ (178,063)	$ -	$ (2,115,545)

Work Paper 25 - Building Lease

Purpose: Identification of the Impact of a New Building Lease

Line No.		FERC Account	Source Reference	FY 2009 Actual	New Lease	Test Year Adjustment
A		B	C	D	E	F
1	**Building Lease Expense**					
2	Lease for 811 Barton Springs Rd.	931	SD-34	$ 1,515,556	$ 2,033,333	$ 517,778
3						
4						

Work Paper 26 - Production Plant

Purpose: Develop Allocators to Sub-Functionalize the Production Function

Line No.		PIS Source Reference	Adjustments Source Reference	Gross Plant In Service 9/30/2009	Gross Plant In Service Adjustments [1]	Gross Plant In Service Test Year	Accumulated Depreciation 9/30/2009	Accumulated Depreciation Adjustments [1]	Accumulated Depreciation Test Year
A		B	C	D	E	F	G	H	I
1	**Steam Power Generation**								
2	Decker Power Plant	SD-1		$ 167,620,590		$ 167,620,590	$ 124,019,508		$ 124,019,508
3	Fayette Power Plant	SD-1	WP 2.3 & SD-4	320,186,851	189,837,407	510,024,258	238,520,609	(3,006,336)	235,514,273
4	Holly Power Plant	SD-1	WP 2.2 & SD-4	10,384,483	(9,509,972)	874,511	7,407,573	(6,978,136)	429,438
5	Misc	SD-1		438,787		438,787	77,829		77,829
6				$ 498,630,712	$ 180,327,435	$ 678,958,146	$ 370,025,519	$ (9,984,472)	$ 360,041,047
7									
8	**Nuclear Power Generation**								
9	South Texas Project	SD-1	SD-4	$ 933,891,167	(7,237,276)	$ 926,653,891	$ 466,090,883	(3,772,882)	$ 462,318,000
10				$ 933,891,167	$ (7,237,276)	$ 926,653,891	$ 466,090,883	$ (3,772,882)	$ 462,318,000
11									
12	**Other Power Generation**								
13	Sand Hill Energy Center	SD-1	WP 2.3	$ 275,659,994	$ 72,869,957	$ 348,529,951	$ 70,003,925	$ 2,428,999	$ 72,432,923
14	Decker Power Plant	SD-1		33,997,128		33,997,128	8,760,742		8,760,742
15	Mueller	SD-1		7,442,119		7,442,119	977,616		977,616
16	Domain	SD-1		3,579,766		3,579,766	927,424		927,424
17	Solar	SD-1		3,186,975		3,186,975	826,368		826,368
18	Wind	SD-1		38,900		38,900	10,078		10,078
19	Fuel Cell	SD-1		5,625		5,625	1,457		1,457
20	Misc	SD-1		22,666		22,666	2,976		2,976
21				$ 323,933,174	$ 72,869,957	$ 396,803,130	$ 81,510,586	$ 2,428,999	$ 83,939,585
22									
23				**$ 1,756,455,053**	**$ 245,960,115**	**$ 2,002,415,168**	**$ 917,626,988**	**$ (11,328,356)**	**$ 906,298,632**
24									
25	**Major Generation Facilities [2,3]**								
26	Decker Power Plant								
27	Fayette Power Plant								
28	South Texas Project								
29	Sand Hill Energy Center								
30									
31									
32		Notes:							
33			[1] Adjustments include the addition of new CTs at SHEC, installation of scrubbers at FPP, retirements in FY 2010 and removal of Holly PIS						
34			[2] Excludes Mueller, Domain, Solar, Wind, Fuel Cell and Misc, as these amounts are either non-electric utility related or insignificant						
35			[3] Used to sub-functionalize production related debt on WP 5.3 - Debt						

Work Paper 26 - Production Plant

Purpose: Develop Allocators to Sub-Functionalize the Production Function

Line No.		Net Plant In Service: 9/30/2009	Net Plant In Service: Adjustments [1]	Net Plant In Service: Test Year	Depreciation Expense: 9/30/2009	Depreciation Expense: Adjustments [1]	Depreciation Expense: Test Year
A		J	K	L	M	N	O
1	**Steam Power Generation**						
2	Decker Power Plant	$ 43,601,082	$ -	$ 43,601,082	$ 4,464,238		$ 4,464,238
3	Fayette Power Plant	81,666,242	192,843,743	274,509,985	8,503,287	6,391,930	14,895,218
4	Holly Power Plant	2,976,910	(2,531,836)	445,073	272,789	(247,112)	25,677
5	Misc	360,958	-	360,958	2,678		2,678
6		$ 128,605,192	$ 190,311,907	$ 318,917,099	$ 13,242,993	$ 6,144,818	$ 19,387,811
7							
8	**Nuclear Power Generation**						
9	South Texas Project	$ 467,800,284	$ (3,464,393)	$ 464,335,891	$ 25,036,012	(171,436)	$ 24,864,576
10		$ 467,800,284	$ (3,464,393)	$ 464,335,891	$ 25,036,012	$ (171,436)	$ 24,864,576
11							
12	**Other Power Generation**						
13	Sand Hill Energy Center	$ 205,656,070	$ 70,440,958	$ 276,097,028	$ 8,943,162	$ 2,428,999	$ 11,372,161
14	Decker Power Plant	25,236,386	-	25,236,386	1,103,036		1,103,036
15	Mueller	6,464,503	-	6,464,503	244,082		244,082
16	Domain	2,652,341	-	2,652,341	116,141		116,141
17	Solar	2,360,608	-	2,360,608	103,497		103,497
18	Wind	28,822	-	28,822	1,262		1,262
19	Fuel Cell	4,168	-	4,168	182		182
20	Misc	19,690	-	19,690	770		770
21		$ 242,422,587	$ 70,440,958	$ 312,863,545	$ 10,512,133	$ 2,428,999	$ 12,941,132
22							
23		**$ 838,828,064**	**$ 257,288,471**	**$ 1,096,116,536**	**$ 48,791,138**	**$ 8,402,381**	**$ 57,193,519**
24							
25	**Major Generation Facilities [2, 3]**						
26	Decker Power Plant						
27	Fayette Power Plant						
28	South Texas Project						
29	Sand Hill Energy Center						
30							
31							
32							
33							
34							
35							

Work Paper 26 - Production Plant

Purpose: Develop Allocators to Sub-Functionalize the Production Function

Line No.		Facility	Name Plate Capacity (MW) Base	Intermediate	Peak	Total
A		P	Q	R	S	T
1	**Steam Power Generation**					
2	Decker Power Plant					
3	Fayette Power Plant					
4	Holly Power Plant					
5	Misc					
6						
7						
8	**Nuclear Power Generation**					
9	South Texas Project					
10						
11						
12	**Other Power Generation**					
13	Sand Hill Energy Center	**Sand Hill Energy Center**	-	300	270	570
14	Decker Power Plant		**0.00%**	**52.63%**	**47.37%**	**100.00%**
15	Mueller			Source Reference: WP 41 - Prod Capacity		
16	Domain					
17	Solar					
18	Wind					
19	Fuel Cell					
20	Misc					
21						
22						
23						
24						
25	**Major Generation Facilities** [2, 3]					
26	Decker Power Plant					
27	Fayette Power Plant					
28	South Texas Project					
29	Sand Hill Energy Center					
30						
31						
32						
33						
34						
35						

Work Paper 26 - Production Plant

Purpose: Develop Allocators to Sub-Functionalize the Production Function

Line No.		Intermediate Gas	Base Load Coal	Base Load Nuclear	Peak Gas	Renewable Wind	Renewable Solar	Total
		Test Year - Gross Plant In Service						
		Power Generation Sub-Functionalized						
A		U	V	W	X	Y	Z	AA
1	**Steam Power Generation**							
2	Decker Power Plant	$ 167,620,590	$ -	$ -	$ -	$ -	$ -	$ 167,620,590
3	Fayette Power Plant	-	510,024,258	-	-	-	-	510,024,258
4	Holly Power Plant	874,511	-	-	-	-	-	874,511
5	Misc	438,787	-	-	-	-	-	438,787
6		$ 168,933,888	$ 510,024,258	$ -	$ -	$ -	$ -	$ 678,958,146
7								
8	**Nuclear Power Generation**							
9	South Texas Project	$ -	$ -	$ 926,653,891	$ -	$ -	$ -	$ 926,653,891
10		$ -	$ -	$ 926,653,891	$ -	$ -	$ -	$ 926,653,891
11								
12	**Other Power Generation**							
13	Sand Hill Energy Center	$ 183,436,816	$ -	$ -	$ 165,093,135	$ -	$ -	$ 348,529,951
14	Decker Power Plant	-	-	-	33,997,128	-	-	33,997,128
15	Mueller	-	-	-	7,442,119	-	-	7,442,119
16	Domain	-	-	-	3,579,766	-	-	3,579,766
17	Solar	-	-	-	-	-	3,186,975	3,186,975
18	Wind	-	-	-	-	38,900	-	38,900
19	Fuel Cell	-	-	-	-	-	5,625	5,625
20	Misc	11,057	-	-	11,610	-	-	22,666
21		$ 183,447,873	$ -	$ -	$ 210,123,757	$ 38,900	$ 3,192,600	$ 396,803,130
22								
23		**$ 352,381,761**	**$ 510,024,258**	**$ 926,653,891**	**$ 210,123,757**	**$ 38,900**	**$ 3,192,600**	**$ 2,002,415,168**
24								
25	**Major Generation Facilities [2, 3]**							
26	Decker Power Plant	$ 167,620,590	$ -	$ -	$ 33,997,128	$ -	$ -	$ 201,617,718
27	Fayette Power Plant	-	510,024,258	-	-	-	-	510,024,258
28	South Texas Project	-	-	926,653,891	-	-	-	926,653,891
29	Sand Hill Energy Center	183,436,816	-	-	165,093,135	-	-	348,529,951
30		$ 351,057,407	$ 510,024,258	$ 926,653,891	$ 199,090,262	$ -	$ -	$ 1,986,825,819
31								
32								
33								
34								
35								

Work Paper 26 - Production Plant

Purpose: Develop Allocators to Sub-Functionalize the Production Function

Line No.		Test Year - Accumulated Depreciation Power Generation Sub-Functionalized Intermediate Gas	Base Load Coal	Base Load Nuclear	Peak Gas	Renewable Wind	Renewable Solar	Total
A		AB	AC	AD	AE	AF	AG	AH
1	**Steam Power Generation**							
2	Decker Power Plant	$ 124,019,508	$ -	$ -	$ -	$ -	$ -	$ 124,019,508
3	Fayette Power Plant	-	235,514,273	-	-	-	-	235,514,273
4	Holly Power Plant	429,438	-	-	-	-	-	429,438
5	Misc	77,829	-	-	-	-	-	77,829
6		$ 124,526,774	$ 235,514,273	$ -	$ -	$ -	$ -	$ 360,041,047
7								
8	**Nuclear Power Generation**							
9	South Texas Project	$ -	$ -	$ 462,318,000	$ -	$ -	$ -	$ 462,318,000
10		$ -	$ -	$ 462,318,000	$ -	$ -	$ -	$ 462,318,000
11								
12	**Other Power Generation**							
13	Sand Hill Energy Center	$ 38,122,591	$ -	$ -	$ 34,310,332	$ -	$ -	$ 72,432,923
14	Decker Power Plant	-	-	-	8,760,742	-	-	8,760,742
15	Mueller	-	-	-	977,616	-	-	977,616
16	Domain	-	-	-	927,424	-	-	927,424
17	Solar	-	-	-	-	-	826,368	826,368
18	Wind	-	-	-	-	10,078	-	10,078
19	Fuel Cell	-	-	-	-	-	1,457	1,457
20	Misc	1,452	-	-	1,524	-	-	2,976
21		$ 38,124,043	$ -	$ -	$ 44,977,639	$ 10,078	$ 827,825	$ 83,939,585
22								
23		**$ 162,650,817**	**$ 235,514,273**	**$ 462,318,000**	**$ 44,977,639**	**$ 10,078**	**$ 827,825**	**$ 906,298,632**
24								
25	**Major Generation Facilities [2, 3]**							
26	Decker Power Plant	$ 124,019,508	$ -	$ -	$ 8,760,742	$ -	$ -	$ 132,780,250
27	Fayette Power Plant	-	235,514,273	-	-	-	-	235,514,273
28	South Texas Project	-	-	462,318,000	-	-	-	462,318,000
29	Sand Hill Energy Center	38,122,591	-	-	34,310,332	-	-	72,432,923
30		$ 162,142,099	$ 235,514,273	$ 462,318,000	$ 43,071,074	$ -	$ -	$ 903,045,446
31								
32								
33								
34								
35								

Work Paper 26 - Production Plant

Purpose: Develop Allocators to Sub-Functionalize the Production Function

Line No.		Test Year - Net Plant In Service / Power Generation Sub-Functionalized						
		Intermediate Gas	Base Load Coal	Base Load Nuclear	Peak Gas	Renewable Wind	Renewable Solar	Total
A		AI	AJ	AK	AL	AM	AN	AO
1	**Steam Power Generation**							
2	Decker Power Plant	$ 43,601,082	$ -	$ -	$ -	$ -	$ -	$ 43,601,082
3	Fayette Power Plant	-	274,509,985	-	-	-	-	274,509,985
4	Holly Power Plant	445,073	-	-	-	-	-	445,073
5	Misc	360,958	-	-	-	-	-	360,958
6		$ 44,407,114	$ 274,509,985	$ -	$ -	$ -	$ -	$ 318,917,099
7								
8	**Nuclear Power Generation**							
9	South Texas Project	$ -	$ -	$ 464,335,891	$ -	$ -	$ -	$ 464,335,891
10		$ -	$ -	$ 464,335,891	$ -	$ -	$ -	$ 464,335,891
11								
12	**Other Power Generation**							
13	Sand Hill Energy Center	$ 145,314,225	$ -	$ -	$ 130,782,803	$ -	$ -	$ 276,097,028
14	Decker Power Plant	-	-	-	25,236,386	-	-	25,236,386
15	Mueller	-	-	-	6,464,503	-	-	6,464,503
16	Domain	-	-	-	2,652,341	-	-	2,652,341
17	Solar	-	-	-	-	-	2,360,608	2,360,608
18	Wind	-	-	-	-	28,822	-	28,822
19	Fuel Cell	-	-	-	-	-	4,168	4,168
20	Misc	9,605	-	-	10,085	-	-	19,690
21		$ 145,323,830	$ -	$ -	$ 165,146,118	$ 28,822	$ 2,364,775	$ 312,863,545
22								
23		**$ 189,730,944**	**$ 274,509,985**	**$ 464,335,891**	**$ 165,146,118**	**$ 28,822**	**$ 2,364,775**	**$ 1,096,116,536**
24								
25	**Major Generation Facilities [2, 3]**							
26	Decker Power Plant	$ 43,601,082	$ -	$ -	$ 25,236,386	$ -	$ -	$ 68,837,468
27	Fayette Power Plant	-	274,509,985	-	-	-	-	274,509,985
28	South Texas Project	-	-	464,335,891	-	-	-	464,335,891
29	Sand Hill Energy Center	145,314,225	-	-	130,782,803	-	-	276,097,028
30		$ 188,915,308	$ 274,509,985	$ 464,335,891	$ 156,019,188	$ -	$ -	$ 1,083,780,372
31								
32								
33								
34								
35								

Work Paper 26 - Production Plant

Purpose: Develop Allocators to Sub-Functionalize the Production Function

Line No.		Intermediate Gas	Base Load Coal	Base Load Nuclear	Peak Gas	Renewable Wind	Renewable Solar	Total
		Test Year - Depreciation Expense						
		Power Generation Sub-Functionalized						
A		AP	AQ	AR	AS	AT	AU	AV
1	**Steam Power Generation**							
2	Decker Power Plant	$ 4,464,238	$ -	$ -	$ -	$ -	$ -	$ 4,464,238
3	Fayette Power Plant	-	14,895,218	-	-	-	-	14,895,218
4	Holly Power Plant	25,677	-	-	-	-	-	25,677
5	Misc	2,678	-	-	-	-	-	2,678
6		$ 4,492,593	$ 14,895,218	$ -	$ -	$ -	$ -	$ 19,387,811
7								
8	**Nuclear Power Generation**							
9	South Texas Project	$ -	$ -	$ 24,864,576	$ -	$ -	$ -	$ 24,864,576
10		$ -	$ -	$ 24,864,576	$ -	$ -	$ -	$ 24,864,576
11								
12	**Other Power Generation**							
13	Sand Hill Energy Center	$ 5,985,348	$ -	$ -	$ 5,386,813	$ -	$ -	$ 11,372,161
14	Decker Power Plant	-	-	-	1,103,036	-	-	1,103,036
15	Mueller	-	-	-	244,082	-	-	244,082
16	Domain	-	-	-	116,141	-	-	116,141
17	Solar	-	-	-	-	-	103,497	103,497
18	Wind	-	-	-	-	1,262	-	1,262
19	Fuel Cell	-	-	-	-	-	182	182
20	Misc	376	-	-	395	-	-	770
21		$ 5,985,724	$ -	$ -	$ 6,850,467	$ 1,262	$ 103,680	$ 12,941,132
22								
23		**$ 10,478,317**	**$ 14,895,218**	**$ 24,864,576**	**$ 6,850,467**	**$ 1,262**	**$ 103,680**	**$ 57,193,519**
24								
25	**Major Generation Facilities [2, 3]**							
26	Decker Power Plant	$ 4,464,238	$ -	$ -	$ 1,103,036	$ -	$ -	$ 5,567,274
27	Fayette Power Plant	-	14,895,218	-	-	-	-	14,895,218
28	South Texas Project	-	-	24,864,576	-	-	-	24,864,576
29	Sand Hill Energy Center	5,985,348	-	-	5,386,813	-	-	11,372,161
30		$ 10,449,586	$ 14,895,218	$ 24,864,576	$ 6,489,849	$ -	$ -	$ 56,699,228
31								
32								
33								
34								
35								

Work Paper 27 - Revenue

Purpose: Develop Base Revenue in the Test Year Under the Current Rate Structure

Line No.		Calculated by Class Source Reference	FY 2009 Actual Base Revenue (SD-56)	Calculated Base Revenue (SD-31)	Revenue Under Reaggregated Classes	Reaggregated Customer Classes Adjustment	Revenue Under Normalized Sales	Normalized Adjustment	Power Factor Adjustment (WP 10 - PF)
A		B	C	D	E	F	G	H	I
1	**Base Revenue**								
2	Residential	SD-31			$ 259,700,558		$ 242,501,132		$ -
3	Secondary Voltage < 10 kW	SD-31			23,461,950		23,586,218		-
4	Secondary Voltage 10 - 49.9 kW	SD-31			57,761,181		57,252,195		442,349
5	Secondary Voltage ≥ 50 kW	SD-31			201,522,551		207,742,170		1,612,577
6	Primary Voltage < 3 MW	SD-31			16,871,129		16,710,024		260,646
7	Primary Voltage 3 - 19.9 MW	SD-31			21,521,683		21,610,267		-
8	Primary Voltage ≥ 20 MW	SD-31			25,502,307		25,508,115		-
9	Transmission Voltage	SD-31			7,744,374		7,731,310		-
10	Service Area Street Lighting	SD-31			6,025,476		4,764,345		-
11	AE-Owned Private Outdoor Lighting	SD-31			1,604,463		1,569,045		-
12	Non-Metered Lighting	SD-31			73,690		73,482		-
13	Metered Lighting	SD-31			220,082		228,765		-
14			$ 614,797,276	$ 617,413,599	$ 622,009,445	$ 4,595,846	$ 609,277,068	$ (12,732,377)	$ 2,315,572
15									
16	Billing Adjustment Factor (Calculation to Actual)			-0.42%	-0.42%		-0.42%		-0.42%
17									
18	Adjusted Totals			**$ 614,797,276**	**$ 619,373,647**	**$ 4,576,371**	**$ 606,695,223**	**$ (12,678,423)**	**$ 2,305,760**
19									

Line No.			Customer Class	Normalized Base Rate Revenue	
20	**Lighting Base Revenue Sub-Detail**				
23	Street and Traffic Lights	SD-31	E05	$ 4,758,521	City of Austin
24	Street and Traffic Lights	SD-31	E05	73,482	TX Dept. of Highways
25	Street and Traffic Lights	SD-31	E05A	5,824	City of Pflugerville
26	State General Service Non-Demand	SD-31	E13	45,318	
27	Greenchoice with E02S	SD-31	GC15A	1,247	
28	Greenchoice with E13	SD-31	GC27	323	
29	General Svc. - ND - Sportslighting	SD-31	E02S	181,878	
30	Security Lighting	SD-31	FACSL	1,569,045	
31	Total			$ 6,635,637	

Work Paper 27 - Revenue

Purpose: Develop Base Revenue in the Test Year Under the Current Rate Structure

Line No.		Test Year Base Revenue (before COA Lighting Adj)	Remove Street Lighting Revenue	Test Year Total Base Revenue
A		J	K	L
1	**Base Revenue**			
2	Residential	$ 242,501,132	$ -	$ 242,501,132
3	Secondary Voltage < 10 kW	23,586,218	-	23,586,218
4	Secondary Voltage 10 - 49.9 kW	57,694,544	-	57,694,544
5	Secondary Voltage ≥ 50 kW	209,354,746	-	209,354,746
6	Primary Voltage < 3 MW	16,970,670	-	16,970,670
7	Primary Voltage 3 - 19.9 MW	21,610,267	-	21,610,267
8	Primary Voltage ≥ 20 MW	25,508,115	-	25,508,115
9	Transmission Voltage	7,731,310	-	7,731,310
10	Service Area Street Lighting	4,764,345	(4,764,345)	-
11	AE-Owned Private Outdoor Lighting	1,569,045	-	1,569,045
12	Non-Metered Lighting	73,482	-	73,482
13	Metered Lighting	228,765	-	228,765
14		$ 611,592,640	$ (4,764,345)	$ 606,828,296
15				
16	Billing Adjustment Factor (Calculation to Actual)	-0.42%	-0.42%	-0.42%
17				
18	Adjusted Totals	**$ 609,000,983**	**$ (4,744,155)**	**$ 604,256,828**
19				
20	**Lighting Base Revenue Sub-Detail**			
21				
22				
23	Street and Traffic Lights			
24	Street and Traffic Lights			
25	Street and Traffic Lights			
26	State General Service Non-Demand			
27	Greenchoice with E02S			
28	Greenchoice with E13			
29	General Svc. - ND - Sportslighting			
30	Security Lighting			
31	Total			

Work Paper 28 - FERC 556

Purpose: Detail FERC 556 to Separate Recoverable and Non-Recoverable Costs and Identify ERCOT Fees for Recovery in the Regulatory Charge

Line No.	Account Code		Source Reference	Eligible Fuel	Non-Eligible Fuel	Total	FY 2009 Actual Eligible Fuel Energy	FY 2009 Actual Eligible Fuel Demand	FY 2009 Actual Regulatory Recovery	FY 2009 Actual Non-Eligible Fuel Capacity
A	B		C	D	E	F	G	H	I	J
1	**System Control and Load Dispatching**									
2		ERCOT Misc Expense	SD-35	$ 186,224	$ -	$ 186,224	$ 186,224	$ -	$ -	$ -
3		ERCOT TCR Credits	SD-35	(4,527,419)	(13,809,364)	(18,336,783)	-	(4,527,419)	-	(13,809,364)
4	**ME**	ERCOT Serv Exp-Capacity	SD-35	-	11,720,144	11,720,144	-	-	-	11,720,144
5	**LE**	ERCOT REC CSG Costs	SD-35	3,367,508	-	3,367,508	3,367,508	-	-	-
6	**DE**	ERCOT Serv Exp-Capacity	SD-35	4,666,192	-	4,666,192	-	4,666,192	-	-
7	**EE**	ERCOT Serv Exp-Energy	SD-35	5,699,253	-	5,699,253	5,699,253	-	-	-
8	**IE**	ERCOT Recv-Load Imbalance	SD-35	1,416,759	-	1,416,759	1,416,759	-	-	-
9	**JE**	ERCOT Recv-Resource Imbalance	SD-35	(7,470,026)	-	(7,470,026)	(7,470,026)	-	-	-
10		ERCOT TCR Expense	SD-35	420,833	10,278,369	10,699,202	-	420,833	-	10,278,369
11				$ 3,759,324	$ 8,189,149	$ 11,948,473	$ 3,199,718	$ 559,606	$ -	$ 8,189,149
12										
13	**HE**	ERCOT Admin Fees	SD-35	$ 7,084,346	$ -	$ 7,084,346	$ -	$ -	$ 7,084,346	$ -
14	**GE**	ERCOT SVC Exp-Other	SD-35	1,785,936	-	1,785,936	1,520,085	265,851	-	-
15	**KE**	ERCOT RECV-Uninstructed RES CH	SD-35	161,435	-	161,435	137,404	24,031	-	-
16				$ 9,031,717	$ -	$ 9,031,717	$ 1,657,489	$ 289,882	$ 7,084,346	$ -
17										
18		Total ERCOT		$ 12,791,041	$ 8,189,149	$ 20,980,190	$ 4,857,207	$ 849,489	$ 7,084,346	$ 8,189,149
19										
20		Payroll & Benefits	SD-35	$ -	$ 1,586,738	$ 1,586,738	$ -	$ -	$ -	$ 1,586,738
21		Other	SD-35	-	145,895	145,895	-	-	-	145,895
22										
23		Total FERC 556 System Control		**$ 12,791,041**	**$ 9,921,783**	**$ 22,712,824**	**$ 4,857,207**	**$ 849,489**	**$ 7,084,346**	**$ 9,921,783**

Work Paper 28.1 - FERC 556

Purpose: Identify the Test Year Cost for the ERCOT Administration Fee

Line No.		Actual Source Reference	FY 2007 Actual	FY 2008 Actual	FY 2009 Actual	FY 2010 Actual	FY 2011 Estimate	Test Year	Total Adjustment
A		B	C	D	E	F	G	H	I
1	**Total ERCOT Administration Fee**								
2	Administration Fee	SD-36	$ 4,447,153	$ 5,016,842	$ 5,052,793	$ 4,788,352	$ 4,938,488	$ 4,938,488	$ (114,304)
3	Nodal Fee	SD-36	1,047,535	1,756,008	2,031,553	3,517,774	4,440,022	4,440,022	2,408,468
4	Texas Regional Entity (TRE) Fee	SD-65	204,634	216,288	220,253	480,206	461,289	461,289	241,036
5			$ 5,699,322	$ 6,989,138	$ 7,304,599	$ 8,786,332	$ 9,839,798	$ 9,839,798	$ 2,535,200
6									
7	**Current Administration Fee ($/MWh generation)**								
8	Rate	SD-65					$ 0.41710		
9									
10	**Current Nodal Implementation Surcharge ($/MWh generation)** [1]								
11	Rate	SD-65					$ 0.37500		
12									
13	**Current Texas Regional Entity Fee ($/MWh generation)**								
14	Rate	SD-65					$ 0.03896		
15									
16	**MWh Generation (excludes bilateral power purchases)**								
17	Traditional	WP 44					9,962,382		
18	Renewable	WP 44					1,877,675		
19							11,840,058		
20									
21	**Administration Fee**						$ 4,938,488		
22									
23	**Nodal Fee**						$ 4,440,022		
24									
25	**Texas Regional Entity Fee**						$ 461,289		
26									
27	Notes:								
28	[1] The Nodal Implementation Surcharge Rate during FY 2009 was $0.169 per MWh generated.								

Work Paper 28.2 - FERC 556

Purpose: Legend to Identify the Expenses Included in Each FERC 556 Account Code, as Shown on WP 28

Line No.	Account Code	Source Reference	Charge Name
A	B	C	D
1	**AR**	SD-37	Non Spin Reserve Service Payment to QSE
2	**AR**	SD-37	OOM Non Spinning Capacity Payment
3	**AR**	SD-37	OOM Regulation Down Capacity Payment
4	**AR**	SD-37	OOM Regulation Up Capacity Payment
5	**AR**	SD-37	OOM Responsive Capacity Payment
6	**AR**	SD-37	Regulation Down Service Payment to QSE
7	**AR**	SD-37	Regulation Up Service Payment to QSE
8	**AR**	SD-37	Responsive Reserve Service Payment to QSE
9	**AR**	SD-37	Local Replacement Reserve to Provider
10	**AR**	SD-37	Zonal Replacement Reserve to Provider
11	**AR**	SD-37	OOM Replacement Capacity Payment
12	**AR**	SD-37	Black Start Standby
13	**AR**	SD-37	RMR Standby
14	**BR**	SD-37	Local Balancing Down to Provider
15	**BR**	SD-37	Local Balancing Up to Provider
16	**BR**	SD-37	OOM Energy Down Payment to Provider
17	**BR**	SD-37	OOM Energy Up Payment to Provider
18	**BR**	SD-37	RMR Energy to Provider
19	**BR**	SD-37	Aggregated OOM_Energy_Down to Provider (SH CC)
20	**BR**	SD-37	Aggregated OOM_Energy_UP to Provider (SH CC)
21	**BR**	SD-37	Aggregated Local Balancing_Energy_Down to Provider (SH CC)
22	**BR**	SD-37	Aggregated Local Balancing_Energy_Up to Provider (SH CC)
23	**CR**	SD-37	RMR Start-Up
24	**DE**	SD-37	Non Spin Reserve Service Charge
25	**DE**	SD-37	Regulation Down Service Charge
26	**DE**	SD-37	Regulation Up Service Charge
27	**DE**	SD-37	Responsive Reserve Service Charge
28	**DE**	SD-37	OOM Replacement Capacity Charge
29	**DE**	SD-37	Replacement Res. Service Under-Sched. Chrg.
30	**DE**	SD-37	Replacement Reserve Uplift Charge
31	**DE**	SD-37	Black Start Capacity Charge
32	**DE**	SD-37	Emergency Interruptible Load Service (EILS)
33	**DE**	SD-37	RMR Reserve Service Charge
34	**DE**	SD-37	OOM Replacement Capacity Charge - ADR Settlement
35	**EE**	SD-37	Local Balancing Service Charge
36	**EE**	SD-37	OOM Energy Charge
37	**EE**	SD-37	Wind OOME Load Allocation Charge
38	**EE**	SD-37	Modified Competitive Solution Method Payment
39	**EE**	SD-37	Modified Competitive Solution Method Charge
40	**EE**	SD-37	MISC_PCRSCE_PAYMENT_CREDIT
41	**EE**	SD-37	MISC_PCRSCE_PAYMENT_DEBIT
42	**GE**	SD-37	Balancing Energy Neutrality Adjustment
43	**GE**	SD-37	Mismatched Schedule Processing Fee
44	**GE**	SD-37	RMR Non-Performance
45	**HE**	SD-37	ERCOT Administration Fee
46	**HE**	SD-37	NODAL IMPLEMENTATION SURCHARGE
47	**IE**	SD-37	Load Imbalance
48	**JE**	SD-37	Resource Imbalance
49	**JE**	SD-37	MisMatch InteroQSE Schedule Received & Delivered
50	**KE**	SD-37	Uninstructed Resource Charge
51	**LE**	SD-37	Balancing Energy CSC Costs Per QSE-STP HOUSTON ZONE
52	**ME**	SD-37	Balancing Energy CSC Costs Per QSE-Wind WEST ZONE
53	**ME**	SD-37	Balancing Energy CSC Cost Per QSE-Wind NORTH ZONE
54	**ME**	SD-37	Wind OOME Payment to Debit(Credit)

Work Paper 29 - Reserves

Purpose: Identify the Test Year Reserve Fund Balances, Targets and Deficiencies (if any)

Line No.		FY 2009 & FY 2010 Balances Source Reference	FY 2009 9/30/2009 Actual	Unaudited FY 2010 9/30/2010 Actual	Under-Recovery Source Reference	Projected FY 2011 Under-Recovery	FY 2011 9/30/2011 Projected	Test Year Source Reference	Test Year
A		B	C	D	E	F	G	H	I
1	**Required Reserve Fund Balance [1]**	SD-38	**$ 442,237,000**	**$ 321,153,000**	SD-39	**$ (20,431,026)**	**$ 300,721,974**		**$ 300,721,974**
2	(excludes restricted reserves for decommissioning and debt as well as deposits)								
3									
4	**Working Capital Reserve Fund**		$ 51,343,997						$ 51,667,404
5	*Target: 45 days of O&M less fuel and purchased power*	Functional Unbundling	*$ 51,343,997*					Functional Unbundling	*$ 51,667,404*
6									
7	Subtotal Reserves Funds after Working Capital Reserve Fund		$ 390,893,003						$ 249,054,570
8									
9	**Strategic Reserve Fund**								
10	Contingency Reserve Fund		$ 68,458,663						$ 68,889,872
11	*Target: 60 days of O&M less fuel and purchased power*	Functional Unbundling	*$ 68,458,663*					Functional Unbundling	*$ 68,889,872*
12	Emergency Reserve Fund		$ 68,458,663						$ 68,889,872
13	*Target: 60 days of O&M less fuel and purchased power*	Functional Unbundling	*$ 68,458,663*					Functional Unbundling	*$ 68,889,872*
14	Rate Stabilization Fund		$ 109,030,479						$ 97,958,754
15	*Target: 90 days of Power Cost (Net of ERCOT Fees)*	WP 16 & WP 28	*$ 109,030,479*					WP 44 & WP 28.1	*$ 97,958,754*
16	Subtotal Strategic Reserve Fund		$ 245,947,805						$ 235,738,498
17									
18	Subtotal Reserves Funds after Strategic Reserve Fund		$ 144,945,198						$ 13,316,072
19									
20	**Repair and Replacement Fund [2]**		$ 57,085,861						$ 13,316,072
21	*Target: 1/2 of annual depreciation*	Functional Unbundling	*$ 57,085,861*					Functional Unbundling	*$ 61,197,672*
22									
23	Subtotal Reserves Funds after Repair and Replacement Fund 2		$ 87,859,337						$ -
24									
25	Total Reserves		$ 442,237,000						$ 300,721,974
26	Total Reserve Requirements		$ 354,377,663						$ 348,603,573
27	Undesignated/Unrestricted Reserve		$ 87,859,337						
28	Reserve Deficiency								$ 47,881,599
29									
30								Years to Resolve Deficiency (if any)	3
31									
32								**Annual Contribution [3]**	**$ 15,960,533**
33									
34	**Non-Nuclear Decommissioning Reserve Funds**								
35									
36	**Non-Nuclear Decommissioning Reserve Requirement**							WP 29.1	**$ 67,169,946**
37									
38	**Non-Nuclear Decommissioning Reserve Balance**								**$ -**
39									
40								Deficiency	$ 67,169,946
41									
42								Years to Resolve Deficiency (if any)	10
43									
44								**Total Annual Non-Nuclear Decommissioning Reserve Contribution**	**$ 6,716,995**
45									
46	Notes:								
47	[1] Sum of Strategic Reserve, Repair and Replacement, Construction and Undesignated/Unrestricted Reserves								
48	[2] Repair and Replacement Fund target of half depreciation is consistent with the capital structure assumptions for the Capital Improvement Program								
49	[3] Annual contribution is assumed not to be reduced by interest earned on the balance, as interest on available reserves contributes to sources of funds in the margin calculation								

Work Paper 29.1 - Reserves

Purpose: Identify the Non-Nuclear Decommissioning Reserve Requirement

Line No.		Capacity Source Reference	Name Plate Capacity MW	Cost Source Reference	Unit Decommissioning Cost $/MW	Total Decommissioning Cost
A		B	C	D	E	F
1	**Decker Power Plant**					
2	Plant Unit 1	WP 41	321	SD-64	$ 32,200	$ 10,336,315
3	Plant Unit 2	WP 41	405	SD-64	32,200	13,041,145
4	Plant Gas Turbine 1	WP 41	50	SD-64	16,100	805,009
5	Plant Gas Turbine 2	WP 41	50	SD-64	16,100	805,009
6	Plant Gas Turbine 3	WP 41	50	SD-64	16,100	805,009
7	Plant Gas Turbine 4	WP 41	50	SD-64	16,100	805,009
8			926			$ 26,597,496
9						
10	**Sand Hill Energy Center**					
11	Gas Turbine 1	WP 41	45	SD-64	$ 16,100	$ 724,508
12	Gas Turbine 2	WP 41	45	SD-64	16,100	724,508
13	Gas Turbine 3	WP 41	45	SD-64	16,100	724,508
14	Gas Turbine 4	WP 41	45	SD-64	16,100	724,508
15	Gas Turbine 6	WP 41	45	SD-64	16,100	724,508
16	Gas Turbine 7	WP 41	45	SD-64	16,100	724,508
17	Combined Cycle 5A & 5C	WP 41	300	SD-64	24,150	7,245,081
18			570			$ 11,592,129
19						
20	**Fayette Power Plant**					
21	Unit 1	WP 41	300	SD-64	$ 48,301	$ 14,490,161
22	Unit 2	WP 41	300	SD-64	48,301	14,490,161
23			600			$ 28,980,322
24						
25	**Total Non-Nuclear Decommissioning Reserve Requirement**					**$ 67,169,946**

Work Paper 30 - Meters
Purpose: Develop Weighted Allocation for Meter Cost in the Test Year

Line No.		Source Reference	Residential	Secondary Voltage < 10 kW	Secondary Voltage 10 - 49.9 kW	Secondary Voltage ≥ 50 kW	Primary Voltage < 3 MW	Primary Voltage 3 - 19.9 MW	Primary Voltage ≥ 20 MW	Transmission Voltage	Metered Lighting	Total
A		B	C	D	E	F	G	H	I	J	K	L
1												
2	**Customer Months**	WP 22	4,374,252	384,008	124,321	38,566	1,224	240	48	48	473	4,923,240
3												
4	**Estimated Meter Count** [1]		364,521	32,001	10,360	3,214	102	20	4	4	39	410,270
5												
6	**Average Meter Cost**	SD-61	$ 234.00	$ 677.00	$ 677.00	$ 1,137.00	$ 5,942.00	$ 5,942.00	$ 6,122.00	$ 75,360.00	$ 234.00	
7												
8	**Weighted Meter Cost**		$ 85,297,914	$ 21,664,455	$ 7,013,766	$ 3,654,165	$ 606,084	$ 118,840	$ 24,488	$ 301,440	$ 9,218	$ 118,690,371
9												
10	Notes:											
11	[1] Calculated as customer-months divided by 12 and, thus, assumes each customer has only one meter											

Work Paper 30.1 - Meters

Purpose: Identify Meters Not in Use for Removal from PIS

Line No.	Source Reference	R/C/I	Description	Quantity	Total Cost	Average Cost ($/Meter)
A	B	C	D	E	F	G
1						
2	SD-40	Com	METER TRANSFORMER 1010KW & K	24	$ 1,416	$ 59.01
3	SD-40	Com	METER COMBO 1/0 INSTTRANSFOR	60	4,999	83.31
4	SD-40	Com	METERING EQUIPMENT SECONDARY	2,546	214,531	84.26
5	SD-40	Com	METER TRANSFORMER 30100KW &	16	1,461	91.32
6	SD-40	Com	METER TRANSFORMER 3010KW & K	2	209	104.65
7	SD-40	Com	METERS SINGLE PHASE	185,711	20,926,929	112.69
8	SD-40	Com	METER DEMAND 3/0 TRANSFOR	54	6,539	121.10
9	SD-40	Com	METERING EQUIPMENT SECONDAR	3,008	455,675	151.49
10	SD-40	Com	METERS - THREE PHASE	3,177	1,840,478	579.31
11	SD-40	Com	METERS-TRANSFORMER VOLTAGE	350	282,714	807.76
12	SD-40	Com	METERS SOLID STATE SWITCHBOA	12	15,312	1,276.00
13				194,960	$ 23,750,263	$ 121.82
14						
15	SD-40	Key Acc	METERS THREE PHASE	2,065	$ 779,269	$ 377.37
16	SD-40	Key Acc	METERS THREE PHASE	1,692	701,875	414.82
17	SD-40	Key Acc	METERS-THREE PHASE	28,401	12,067,703	424.90
18	SD-40	Key Acc	METERS - LOAD SURVEY, ALL SI	50	27,778	555.56
19	SD-40	Key Acc	METERING EQUIPMENT PRIMARY 3	100	60,519	605.19
20	SD-40	Key Acc	METERING EQUIPMENT PRIMARY	263	191,116	726.68
21	SD-40	Key Acc	METERS - LOAD SURVEY	133	127,844	961.23
22	SD-40	Key Acc	METERS-SELF REPORTING	263	271,463	1,032.18
23	SD-40	Key Acc	METERS-WIRELESS	68	83,744	1,231.53
24	SD-40	Key Acc	METER	3	8,051	2,683.67
25				33,038	$ 14,319,362	$ 433.42
26						
27	SD-40	Res	METER BASE 30 200 AMP--EACH	3	$ 105	$ 34.91
28	SD-40	Res	METERS-SINGLE PHASE	124,694	6,947,636	55.72
29	SD-40	Res	METERS-AUTOMATED	132,179	8,073,257	61.08
30	SD-40	Res	METERS - SINGLE PHASE OH	5,324	352,617	66.23
31	SD-40	Res	METERS SINGLE PHASE	9,836	652,179	66.31
32	SD-40	Res	METERS - SINGLE PHASE UG	2,556	175,834	68.79
33	SD-40	Res	METERS - SINGLE PHASE	72,165	5,137,410	71.19
34	SD-40	Res	METERS,-SINGLE PHASE	4,140	418,759	101.15
35	SD-40	Res	METERS-LOAD SURVEY	21,392	2,200,614	102.87
36	SD-40	Res	METERS-PEDESTAL-DOUBLE/SINGLE	435	254,632	585.36
37	SD-40	Res	METER SINGLE PHASE CLASS II	2,253	56,552	25.10
38	SD-40	Res	METER BASE 1/0 150 AMP--EAC	7,508	192,044	25.58
39	SD-40	Res	METER BASE 30 200AMP	460	15,775	34.29
40				382,945	$ 24,477,414	$ 63.92
41						
42	SD-40	SYSTEM	METERS-SOLID STATE-MULTIFUNC	39	$ 134,043	$ 3,437.00
43	SD-40	SYSTEM	METERS SOLIDST MULTIFUNCTION	14	51,884	3,706.00
44	SD-40	SYSTEM	METERS-REVENUE METERS	18	72,190	4,010.54
45	SD-40	SYSTEM	METERSSOLIDSTATESWITCHBOARD	9	36,336	4,037.33
46	SD-40	SYSTEM	METERS-REVENUE	22	91,143	4,142.85
47				102	$ 385,595	$ 3,780.35
48						
49	SD-40	NotUse	7ETER BASE 10 100 AMP--EACH	1,520	$ 5,396	$ 3.55
50	SD-40	NotUse	METER BASE 10 100AMP--EACH	11,756	50,908	4.33
51	SD-40	NotUse	METER BASE 10 100 AMP--EACH	29,423	137,113	4.66
52	SD-40	NotUse	METER BASE 1/0 100 AMP--EAC	45,488	245,208	5.39
53	SD-40	NotUse	METER BASE 10 50 AMP--EACH	66	560	8.48
54	SD-40	NotUse	METER BASE 1/0 150 AMP--EAC	21,362	217,571	10.18
55	SD-40	NotUse	METER BOX SPECIAL NETWORK--E	1,347	15,809	11.74
56	SD-40	NotUse	METER BOX 30ECIAL NETWORK--1	948	11,650	12.29
57	SD-40	NotUse	METER SINGLE PHASE CLASS I--	33,386	518,285	15.52
58	SD-40	NotUse	METER SINGLE PHASE CLASS I-	26,239	433,617	16.53
59	SD-40	NotUse	METER BOX 4KV 2M-EA	1,043	19,927	19.11
60	SD-40	NotUse	METER BOX 4KV 2M--EA	3,245	63,343	19.52
61	SD-40	NotUse	METER BOX SPECIAL NETWORK IM	286	6,336	22.16
62	SD-40	NotUse	WATTHOUR METER 1/0 SELF CON	11,904	267,126	22.44
63	SD-40	NotUse	WATTHOUR METER 1/0 INST TRA	44	1,107	25.15
64	SD-40	NotUse	METER 3 WINDOWS 3M--EACH	66	2,223	33.69
65	SD-40	NotUse	METER 3 PHASE CLASS I--EA	24	827	34.47
66	SD-40	NotUse	METER 3 PHASE CLASS I--EACH	396	15,686	39.61
67	SD-40	NotUse	METER COMBO W&D 30 CLASS I-	6	274	45.60
68	SD-40	NotUse	METER COMBO W&D 10 CLASS+I--	12	574	47.84
69	SD-40	NotUse	METER 3 WINDOWS 2M--EACH	14	686	48.99
70	SD-40	NotUse	METER 3 PHASE CLASS II--EA	120	6,061	50.51

Work Paper 30.1 - Meters
Purpose: Identify Meters Not in Use for Removal from PIS

Line No.	Source Reference	R/C/I	Description	Quantity	Total Cost	Average Cost ($/Meter)
A	B	C	D	E	F	G
71	SD-40	NotUse(	METERING EQUIP SECONDARY POL	2,246	114,164	50.83
72	SD-40	NotUse(	METER 3 PHASE CLASS III--EA	8	408	51.00
73	SD-40	NotUse(	METER 3 PHASE CLASS-IV--EACH	24	1,310	54.60
74	SD-40	NotUse(	METER DEMAND 1/0 SELF CON	12	676	56.37
75	SD-40	NotUse(	METER 3 PHASE CLASS IV--EA	68	4,058	59.67
76	SD-40	NotUse(	METER 3 PHASE CLASS-	8	480	60.00
77	SD-40	NotUse(	METER 3 PHASE CLASS II--EACH	1,293	78,061	60.37
78	SD-40	NotUse(	WATTHOUR METER 3/0 SELF CON	129	8,833	68.47
79	SD-40	NotUse(	METER 3 PHASE CLASS II EA	6	411	68.47
80	SD-40	NotUse(	METER COMBO 1/0 SELFCONTAINE	24	1,645	68.54
81	SD-40	NotUse(	METER COMBO W&D ONE PHASE CL	85	5,921	69.66
82	SD-40	NotUse(	METER DEMAND 3/0 SELF-CON	36	2,546	70.73
83	SD-40	NotUse(	METER 3 PHASE CLASS IV--EACH	237	16,976	71.63
84	SD-40	NotUse(	METER 3 PHASE CLASS III--EAC	37	2,774	74.98
85	SD-40	NotUse(	METER DEMAND 3 PHASECLASS II	11	845	76.78
86	SD-40	NotUse(	METER DEMAND 3/0 SELF CON	46	3,532	76.78
87	SD-40	NotUse(	METER DEMAND 1/0 TRANSFOR	13	1,086	83.57
88	SD-40	NotUse(	METER 3 PHASE CLASS III EA	4	379	94.69
89	SD-40	NotUse(	METERS-LOAD SURVEY,ALL SIZES	4,998	487,445	97.53
90	SD-40	NotUse(	WATTHOUR METER 3/0	28	2,736	97.71
91	SD-40	NotUse(	METERS-LOAD SURVEY ALL SIZES	5,019	501,455	99.91
92	SD-40	NotUse(	METERS LOAD SURVEY ALL SIZES	6,236	626,931	100.53
93	SD-40	NotUse(	METER 3 PHASE CLASS V--EACH	105	11,090	105.62
94	SD-40	NotUse(	WATTHOUR METER 3/0 INST TRA	128	13,799	107.80
95	SD-40	NotUse(	METER 3 PHASE CLASS IV EA	69	7,485	108.48
96	SD-40	NotUse(	METER COMBO 3/0 SELFCONTAINE	28	3,075	109.83
97	SD-40	NotUse(	METER COMBO 3/0 INST	40	5,178	129.46
98	SD-40	NotUse(	METER 3 PHASE CLASS V--EA	4	557	139.20
99	SD-40	NotUse(	METER COMBO 3/0 INSTTRANSFOR	156	22,554	144.58
100	SD-40	NotUse(	METER TRANSFORMER GRAPHIC	2	312	156.00
101	SD-40	NotUse(	METERS - NETWORK, ALL SIZES	76	12,244	161.11
102	SD-40	NotUse(	METER TRANSFORMER LINCOLN	4	728	181.92
103	SD-40	NotUse(	METER SWITCHBOARD 2 STATOR 3	4	827	206.67
104	SD-40	NotUse(	METER DEMAND CLASS V11--EAC	6	1,256	209.41
105	SD-40	NotUse(	METER DEMAND CLASS 1X -3 PHA	2	551	275.27
106	SD-40	NotUse(	METER SWITCHBOARD 3 STATOR 3	8	2,858	357.19
107	SD-40	NotUse(	METERS-COMPUTER CONTROL SANG	1,319	483,045	366.22
108	SD-40	NotUse(	METERS-CENTRON	2,323	905,765	389.91
109	SD-40	NotUse(	METERS-SENTINEL	4,942	2,102,837	425.50
110	SD-40	NotUse(	METERS - COMPUTER CONTROL,SA	314	156,972	499.91
111	SD-40	NotUse(	METERS - THREE PHASE OH	989	501,605	507.18
112	SD-40	NotUse(	METERS,-THREE PHASE	1,347	727,540	540.12
113	SD-40	NotUse(	METER BOXES 6X12X7	16	8,650	540.63
114	SD-40	NotUse(	METERS- THREE PHASE	1,399	801,253	572.73
115	SD-40	NotUse(	METERS -THREE PHASE	2,200	1,273,072	578.67
116	SD-40	NotUse(	METERS-INDICATING	811	478,089	589.51
117	SD-40	NotUse(	LOAD RESEARCH SURVEYRECORDER	36	22,180	616.10
118	SD-40	NotUse(	DATA RECORDER	8	4,960	620.00
119	SD-40	NotUse(	Meters	49	32,601	665.32
120	SD-40	NotUse(	METERS-SOLID STATE SWITCHBOA	180	123,255	684.75
121	SD-40	NotUse(	METERS - WATT HOUR SELF RPTN	14	9,912	708.01
122	SD-40	NotUse(	METERS - ELECTRONIC, DEMAND	185	138,835	750.46
123	SD-40	NotUse(	METERS-ELECTRONIC, DEMAND	215	164,787	766.45
124	SD-40	NotUse(	METERS - THREE PHASE UG	190	158,696	835.24
125	SD-40	NotUse(	METER PHASE ANGLE ARBITR 911	2	2,700	1,350.00
126	SD-40	NotUse(	METER,PHASE ANGLE ARBITR 911	1	1,350	1,350.00
127	SD-40	NotUse(	PHASE ANGLE METER 911A	1	1,352	1,351.89
128	SD-40	NotUse(	METERS - SANGAMO COMP CONTRO	8	27,076	3,384.50
129	SD-40	NotUse(	POLYPHASE CIRCUIT ANALYZER	1	5,920	5,920.00
130	SD-40	NotUse(	MCM DEWDICATOR W/80 TO 20 DE	1	8,644	8,644.00
131	SD-40	NotUse(	END USE METERING SYS - METER	1	47,910	47,910.00
132	SD-40	NotUse(	METER READING SYSTEM	1	291,068	291,068.00
133	SD-40	NotUse(	METERING SYSTEM	1	528,766	528,766.44
134				226,449	$ 12,974,313	$ 57.29
135						
136				837,494	$ 75,906,947	$ 90.64
137						
138						
139				Total	Removal From PIS	Subtotal
140				$ 75,906,947	$ (12,974,313)	$ 62,932,634

Work Paper 31 - Meter Reading
Purpose: Estimate Test Year Cost of Meter Reading

Line No.		FY 2009 Source Reference	FY 2009 Count of Electric Meter Reads			FERC Account	FY 2009 Actual Meter Reading Expense			FY 2011 Source Reference	FY 2011 Estimate [2]	Test Year Adjustment
			Residential	Non-Residential	Total		Residential	Non-Residential	Total			
A		B	C	D	E	F	G	H	I	J	K	L
1	**Meter Reading**											
2	RMC Corix, manual Reads [1]	SD-41	1,341,954	356,687	1,698,641	902	$ 1,075,493	$ 573,399	$ 1,648,892	SD-42	$ 541,375	$ (1,107,517)
3	ESD L+G AMR Costs	SD-41	3,342,701	339,725	3,682,426	902	3,334,477	573,292	3,907,769	SD-43	7,062,813	3,155,044
4			4,684,655	696,412	5,381,067		$ 4,409,971	$ 1,146,691	$ 5,556,662		$ 7,604,188	$ 2,047,526
5												
6	Notes:											
7	[1] Includes re-read meters, move-in-move-out reads, DNP reads											
8	[2] Reflects the cost of a new contract for meter reading											

Work Paper 31.1 - Meter Reading

Purpose: Identify Meter Reading Expenses in FY 2009 that Should be Reclassified

Line No.		FERC Account	FY 2009 Source Reference	FY 2009 Actual	Test Year	Total Adjustment
A		B	C	D	E	F
1						
2	Cellnet Technology Inc	586	SD-71	$ 1,131,023	$ -	$ (1,131,023)
3	Cellnet Technology Inc	902	SD-71	2,650,672	3,781,694	1,131,023
4				$ 3,781,694	$ 3,781,694	$ -

WP 32 - Transmission Matrix Cost

Purpose: Calculate the Cost of Transmission of Electricity by Others (FERC 565) in the Test Year

Line No.		2011 Matrix	Normalized 2011 Matrix	Difference	FY 2009 Source Reference	FY 2009	Normalized 2011 Matrix	Adjustment
A		B	C	D	E	F	G	H
1	**Matrix Expense and Revenue Adjustments**							
2								
3	Transmission of Electricity by Others	$ 66,414,603	$ 65,915,251	$ (499,352)	Functional Unbundling	$ 58,477,601	$ 65,915,251	**$ 7,437,651**
4								
5								
6	**Source Reference: SD-44**							
7	**Public Utility Commission of Texas**							
8	**Docket No. 38900**							
9	**2011 Net Wholesale Trans. Matrix Charges for ERCOT**							
10	**Access Costs & Total Transmission Costs**							
11								

Line No.			
12	**2010 Actual 4CP's**		
13			
14		AENX	Total
15	Access Fee ($/KW)	1.0024660	$28.09546
16	Average 4CP (KW)	2,363,891	61,368,963
17	AENX	$2,369,720	$66,414,603
18	Total	$61,520,298	$1,724,189,261
19			
20	**2010 Matrix with Normalized TY 2009 Austin Energy Load**		
21			
22		AENX	Total
23	Access Fee ($/KW)	1.0024660	$28.09546
24	Average 4CP (KW)	2,346,118	61,351,189
25	AENX	$2,351,903	$65,915,251
26	Total	$61,502,481	$1,723,689,909

WP 33 - Regulatory Asset Deferral

Purpose: Audit Adjustment Recorded in FY 2009 for South Texas Project OPEB

Line No.	Source Reference	FERC Account	Total Adjustment
A	B	C	D
1	SD-57	926	$ (1,748,752)

WP 34 - Distribution Allocation

Purpose: Identify Distribution Investment Costs for Sub-Functionalization in the Test Year

Line No.		Source Reference	Calculated Cost	Calculated Footage	Cost per Foot	Weighting Factor	Miles	Weighted Miles	Allocation Proportion
A		B	C	D	E	F	G	H	I
1	**Distribution Overhead**								
2	1 Phase- 7.2 kV LN	SD-45	$ 9,648.57	1,000	$ 9.65	1.00	615	615	24.5%
3									
4	3 Phase - 12.5 kV LL	SD-45	$ 14,076.70	1,000	$ 14.08	1.46	1,297	1,892	75.5%
5									
6								2,506	100.0%
7									
8	**Distribution Underground**								
9	7.2 kV	SD-45	$ 40,913.09	1,000	$ 40.91	1.00	2,391	2,391	53.5%
10									
11	12.5 kV	SD-45	$ 51,674.19	1,000	$ 51.67	1.26	508		
12	35kV Network	SD-45	$ 104,326.64	5,280	$ 19.76	0.48	124		
13	12.47kV Network	SD-45	$ 244,807.20	5,280	$ 46.37	1.13	89		
14	Sub-Total					2.88	721	2,075	46.5%
15									
16	Total						3,112	4,466	100.0%

Work Paper 35 - Insurance

Purpose: Reclassify Prepaid Insurance

Line No.		FERC Account	Source Reference	Total Adjustment
A		B	C	E
1	**Insurance**			
2	Property Insurance	924	SD-74 & SD-75	$ 2,382,695
3	Injuries and Damages	925	SD-74 & SD-75	(2,382,695)
4				$ -

Work Paper 36 - Customer Related Business Activities

Purpose: Isolation of Selected Business Activities within the Customer Accounts and Customer Service and Information FERC Accounts

Line No.	FERC Account		FY 2009 Source Reference	Adjustment Source Reference	FY 2009 Actual	Adjustment	Test Year
A	B		C	D	E	F	G
1	**Energy Efficiency Services** [1]						
2	901	Supervision	SD-46		$ 46,997		$ 46,997
3	902	Meter Reading Expenses	SD-46		36,647		36,647
4	907	Supervision	SD-46 & SD-47		2,844,262		2,844,262
5	908	Customer Assistance Expenses	SD-46 & SD-47	SD-47	14,559,321	2,707,917	17,267,238
6	909	Informational & Instructional Advertising Expenses	SD-46		893,792		893,792
7	910	Misc Customer Service & Informational Expenses	SD-46 & SD-47		378,115		378,115
8	912	Demonstrating & Selling Expense	SD-46		13,690		13,690
9	913	Advertising Expense	SD-46		(4,473)		(4,473)
10	916	Miscellaneous Sales Expense	SD-46		9,110		9,110
11					$ 18,777,461		$ 21,485,378
12							
13	**Green Building** [1]						
14	901	Supervision	SD-46		$ 73,937		$ 73,937
15	907	Supervision	SD-46		487,349		487,349
16	908	Customer Assistance Expenses	SD-46		1,291,843		1,291,843
17	910	Misc Customer Service & Informational Expenses	SD-46		28,852		28,852
18					$ 1,881,981		$ 1,881,981
19							
20	**Solar Rebate** [1]						
21	907	Supervision	SD-47		$ 40,350		$ 40,350
22	908	Customer Assistance Expenses	SD-47	SD-47	6,992,973	(2,707,917)	4,285,056
23	910	Misc Customer Service & Informational Expenses	SD-47		27,364		27,364
24					$ 7,060,687		$ 4,352,770
25							
26	**Key Accounts** [2]						
27	902	Meter Reading Expenses	SD-46		$ 617		$ 617
28	911	Supervision	SD-46		17,762		17,762
29	912	Demonstrating & Selling Expense	SD-46	WP 38	1,415,009	(57,402)	1,357,607
30	916	Miscellaneous Sales Expense	SD-46		1,669		1,669
31					$ 1,435,057		$ 1,377,654
32							
33	Notes:						
34	[1] Business activity to be moved to the Production Function						
35	[2] Isolate as its own sub-function within the Customer Function						

Work Paper 37 - Allocation of Customer Related Expenses to G&A FERCs

Purpose: Identification of Certain Customer Accounts and Customer Service Expenses to be Reallocated to General and Administrative FERC Accounts

Line No.	FERC Account		Source Reference	FY 2009 Actual	Adjustment	Test Year
A	B		C	D	E	F
1	**Expenses to be Moved to Administrative and General FERCs**					
2	***Customer Accounts Expenses (901 - 905) Moved to FERC 920 (Labor)***					
3	**AE Laboratory Services**					
4	902	Meter Reading Expenses	SD-46	$ -		$ -
5	**Decker Power Plant**					
6	902	Meter Reading Expenses	SD-46	$ -		$ -
7	**Engineering & Construction**					
8	902	Meter Reading Expenses	SD-46	$ -		$ -
9	**Financial Support Regulated Operations**					
10	902	Meter Reading Expenses	SD-46	$ -		$ -
11	903	Customer Records and Collection Expenses	SD-46	-		-
12	**General Manager**					
13	901	Supervision	SD-46	$ -		$ -
14	**Information Technology & Telecommunications**					
15	905	Miscellaneous Customer Accounts Expenses	SD-46	$ -		$ -
16	**ITT Business Technology Ops**					
17	902	Meter Reading Expenses	SD-46	$ 29,168		$ 29,168
18	905	Miscellaneous Customer Accounts Expenses	SD-46	-		-
19	**ITT Customer Relations Mgt Services**					
20	903	Customer Records and Collection Expenses	SD-46	$ -		$ -
21	905	Miscellaneous Customer Accounts Expenses	SD-46	-		-
22	**ITT Development, Data & Arch Services**					
23	903	Customer Records and Collection Expenses	SD-46	$ 142,254		$ 142,254
24	905	Miscellaneous Customer Accounts Expenses	SD-46	-		-
25	**ITT Infrastructure Management**					
26	902	Meter Reading Expenses	SD-46	$ -		$ -
27	903	Customer Records and Collection Expenses	SD-46	3,599		3,599
28	905	Miscellaneous Customer Accounts Expenses	SD-46	-		-
29	**ITT Project Management Office**					
30	902	Meter Reading Expenses	SD-46	$ 2,155		$ 2,155
31	905	Miscellaneous Customer Accounts Expenses	SD-46	-		-
32	**ITT Web & Quality Mgt Services**					
33	905	Miscellaneous Customer Accounts Expenses	SD-46	$ -		$ -
34	**Regulated Operations**					
35	903	Customer Records and Collection Expenses	SD-46	$ 663		$ 663
36	**Security Management**					
37	901	Supervision	SD-46	$ -		$ -
38	**Trans & Substation Engineering & Constrc**					
39	902	Meter Reading Expenses	SD-46	$ -		$ -
40				**$ 177,839**		**$ 177,839**
41						
42	***Customer Accounts Expenses (901 - 905) Moved to FERC 930 (Non-Labor Expenses)***					
43	**AE Laboratory Services**					
44	902	Meter Reading Expenses	SD-46	$ 724		$ 724
45	**Decker Power Plant**					
46	902	Meter Reading Expenses	SD-46	$ 21		$ 21
47	**Engineering & Construction**					
48	902	Meter Reading Expenses	SD-46	$ 63		$ 63
49	**Financial Support Regulated Operations**					
50	902	Meter Reading Expenses	SD-46	$ 3,776		$ 3,776
51	903	Customer Records and Collection Expenses	SD-46	650		650
52	**General Manager**					
53	901	Supervision	SD-46	$ 68		$ 68
54	**Information Technology & Telecommunications**					
55	905	Miscellaneous Customer Accounts Expenses	SD-46	$ (13,599)		$ (13,599)
56	**ITT Business Technology Ops**					
57	902	Meter Reading Expenses	SD-46	$ -		$ -
58	905	Miscellaneous Customer Accounts Expenses	SD-46	(17,410)		(17,410)
59	**ITT Customer Relations Mgt Services**					
60	903	Customer Records and Collection Expenses	SD-46	$ 40		$ 40
61	905	Miscellaneous Customer Accounts Expenses	SD-46	(2,893)		(2,893)

Work Paper 37 - Allocation of Customer Related Expenses to G&A FERCs

Purpose: Identification of Certain Customer Accounts and Customer Service Expenses to be Reallocated to General and Administrative FERC Accounts

Line No.	FERC Account		Source Reference	FY 2009 Actual	Adjustment	Test Year
A	B		C	D	E	F
62	**ITT Development, Data & Arch Services**					
63	903	Customer Records and Collection Expenses	SD-46	$ -		$ -
64	905	Miscellaneous Customer Accounts Expenses	SD-46	(17,976)		(17,976)
65	**ITT Infrastructure Management**					
66	902	Meter Reading Expenses	SD-46	$ (897)		$ (897)
67	903	Customer Records and Collection Expenses	SD-46	-		-
68	905	Miscellaneous Customer Accounts Expenses	SD-46	(19,689)		(19,689)
69	**ITT Project Management Office**					
70	902	Meter Reading Expenses	SD-46	$ -		$ -
71	905	Miscellaneous Customer Accounts Expenses	SD-46	(163,099)		(163,099)
72	**ITT Web & Quality Mgt Services**					
73	905	Miscellaneous Customer Accounts Expenses	SD-46	$ (28,285)		$ (28,285)
74	**Regulated Operations**					
75	903	Customer Records and Collection Expenses	SD-46	$ -		$ -
76	**Security Management**					
77	901	Supervision	SD-46	$ 156		$ 156
78	**Trans & Substation Engineering & Constrc**					
79	902	Meter Reading Expenses	SD-46	$ 482		$ 482
80				**$ (257,868)**		**$ (257,868)**
81						
82	**Customer Accounts Expense Summary**					
83	*Moved to FERC 920 (Labor)*					
84	901	Supervision		$ -	$ -	$ -
85	902	Meter Reading Expenses		31,323	-	31,323
86	903	Customer Records and Collection Expenses		146,516	-	146,516
87	904	Uncollectible Accounts		-	-	-
88	905	Miscellaneous Customer Accounts Expenses		-	-	-
89				**$ 177,839**	**$ -**	**$ 177,839**
90						
91	*Moved to FERC 930 (Non-Labor Expenses)*					
92	901	Supervision		$ 224	$ -	$ 224
93	902	Meter Reading Expenses		4,169	-	4,169
94	903	Customer Records and Collection Expenses		690	-	690
95	904	Uncollectible Accounts		-	-	-
96	905	Miscellaneous Customer Accounts Expenses		(262,951)	-	(262,951)
97				**$ (257,868)**	**$ -**	**$ (257,868)**
98						
99	***Cust. Service & Information Expense (907 - 916) Moved to FERC 920 (Labor)***					
100	**Business Development & Contract Compliance**					
101	916	Miscellaneous Sales Expense	SD-46	$ -		$ -
102	**Corporate**					
103	907	Supervision	SD-46	$ -		$ -
104	908	Customer Assistance Expenses	SD-46	-		-
105	912	Demonstrating & Selling Expense	SD-46	-		-
106	916	Miscellaneous Sales Expense	SD-46	-		-
107	**CTECC Facilities Planning**					
108	907	Supervision	SD-46	$ -		$ -
109	**Decker Power Plant**					
110	907	Supervision	SD-46	$ 11,586		$ 11,586
111	908	Customer Assistance Expenses	SD-46	7,894		7,894
112	**Emerging Transportation Technology (Urban Rail)**					
113	907	Supervision	SD-46	$ (2,873)		$ (2,873)
114	908	Customer Assistance Expenses	SD-46	443		443
115	909	Informational & Instructional Advertising Expenses	SD-46	-		-
116	910	Misc Customer Service & Informational Expenses	SD-46	-		-
117	**Energy & Market Operations**					
118	908	Customer Assistance Expenses	SD-46	$ 55,630		$ 55,630
119	912	Demonstrating & Selling Expense	SD-46	-		-
120	**General Manager**					
121	911	Supervision	SD-46	$ 48,324		$ 48,324
122	912	Demonstrating & Selling Expense	SD-46	-		-

Work Paper 37 - Allocation of Customer Related Expenses to G&A FERCs

Purpose: Identification of Certain Customer Accounts and Customer Service Expenses to be Reallocated to General and Administrative FERC Accounts

Line No.	FERC Account		Source Reference	FY 2009 Actual	Adjustment	Test Year
A	B		C	D	E	F
123	**Holly Power Plant**					
124	907	Supervision	SD-46	$ -		$ -
125	**Human Resources**					
126	910	Misc Customer Service & Informational Expenses	SD-46	$ 7,608		$ 7,608
127	911	Supervision	SD-46	14,114		14,114
128	**ITT Customer Relations Mgt Services**					
129	908	Customer Assistance Expenses	SD-46	$ -		$ -
130	**ITT Infrastructure Management**					
131	907	Supervision	SD-46	$ 993		$ 993
132	**ITT Project Management Office**					
133	908	Customer Assistance Expenses	SD-46	$ 1,304		$ 1,304
134	**ITT Web & Quality Mgt Services**					
135	916	Miscellaneous Sales Expense	SD-46	$ -		$ -
136	**Office of COO**					
137	910	Misc Customer Service & Informational Expenses	SD-46	$ -		$ -
138	912	Demonstrating & Selling Expense	SD-46	-		-
139	**Power Production Engineering**					
140	907	Supervision	SD-46	$ -		$ -
141	**Project & Business Development**					
142	910	Misc Customer Service & Informational Expenses	SD-46	$ -		$ -
143	912	Demonstrating & Selling Expense	SD-46	-		-
144	**Sand Hill Energy Center**					
145	907	Supervision	SD-46	$ -		$ -
146	**Shared Services**					
147	908	Customer Assistance Expenses	SD-46	$ -		$ -
148	**Systems Operations & Reliability**					
149	907	Supervision	SD-46	$ -		$ -
150	**Trans & Substation Engineering & Constrc**					
151	907	Supervision	SD-46	$ -		$ -
152				**$ 145,023**		**$ 145,023**
153						
154	***Cust. Service & Information Expense (907 - 916) Moved to FERC 930 (Non-Labor Expenses)***					
155	**Business Development & Contract Compliance**					
156	916	Miscellaneous Sales Expense	SD-46	$ 848		$ 848
157	**Corporate**					
158	907	Supervision	SD-46	$ (1,487)		$ (1,487)
159	908	Customer Assistance Expenses	SD-46	(337)		(337)
160	912	Demonstrating & Selling Expense	SD-46	118		118
161	916	Miscellaneous Sales Expense	SD-46	118		118
162	**CTECC Facilities Planning**					
163	907	Supervision	SD-46	$ 320		$ 320
164	**Decker Power Plant**					
165	907	Supervision	SD-46	$ 144		$ 144
166	908	Customer Assistance Expenses	SD-46	5		5
167	**Emerging Transportation Technology (Urban Rail)**					
168	907	Supervision	SD-46	$ 26,544		$ 26,544
169	908	Customer Assistance Expenses	SD-46	-		-
170	909	Informational & Instructional Advertising Expenses	SD-46	40,210		40,210
171	910	Misc Customer Service & Informational Expenses	SD-46	366		366
172	**Energy & Market Operations**					
173	908	Customer Assistance Expenses	SD-46	$ (303)		$ (303)
174	912	Demonstrating & Selling Expense	SD-46	283		283
175	**General Manager**					
176	911	Supervision	SD-46	$ -		$ -
177	912	Demonstrating & Selling Expense	SD-46	778		778
178	**Holly Power Plant**					
179	907	Supervision	SD-46	$ -		$ -
180	**Human Resources**					
181	910	Misc Customer Service & Informational Expenses	SD-46	$ -		$ -
182	911	Supervision	SD-46	-		-
183	**ITT Customer Relations Mgt Services**					

Work Paper 37 - Allocation of Customer Related Expenses to G&A FERCs

Purpose: Identification of Certain Customer Accounts and Customer Service Expenses to be Reallocated to General and Administrative FERC Accounts

Line No.	FERC Account		Source Reference	FY 2009 Actual	Adjustment	Test Year
A	B		C	D	E	F
184	908	Customer Assistance Expenses	SD-46	$ 748		$ 748
185	**ITT Infrastructure Management**					
186	907	Supervision	SD-46	$ -		$ -
187	**ITT Project Management Office**					
188	908	Customer Assistance Expenses	SD-46	$ -		$ -
189	**ITT Web & Quality Mgt Services**					
190	916	Miscellaneous Sales Expense	SD-46	$ 3,619		$ 3,619
191	**Office of COO**					
192	910	Misc Customer Service & Informational Expenses	SD-46	$ 374		$ 374
193	912	Demonstrating & Selling Expense	SD-46	840		840
194	**Power Production Engineering**					
195	907	Supervision	SD-46	$ 288		$ 288
196	**Project & Business Development**					
197	910	Misc Customer Service & Informational Expenses	SD-46	$ 2,174		$ 2,174
198	912	Demonstrating & Selling Expense	SD-46	8		8
199	**Sand Hill Energy Center**					
200	907	Supervision	SD-46	$ 1,509		$ 1,509
201	**Shared Services**					
202	908	Customer Assistance Expenses	SD-46	$ 14		$ 14
203	**Systems Operations & Reliability**					
204	907	Supervision	SD-46	$ (230,010)		$ (230,010)
205	**Trans & Substation Engineering & Constrc**					
206	907	Supervision	SD-46	$ 2,166		$ 2,166
207				**$ (150,664)**		**$ (150,664)**
208						
209	**Cust. Service & Information Expense Summary**					
210	*Moved to FERC 920 (Labor)*					
211	907	Supervision		$ 9,706	$ -	$ 9,706
212	908	Customer Assistance Expenses		65,271	-	65,271
213	909	Informational & Instructional Advertising Expenses		-	-	-
214	910	Misc Customer Service & Informational Expenses		7,608	-	7,608
215	911	Supervision		62,438	-	62,438
216	912	Demonstrating & Selling Expense		-	-	-
217	913	Advertising Expense		-	-	-
218	916	Miscellaneous Sales Expense		-	-	-
219				**$ 145,023**	**$ -**	**$ 145,023**
220						
221	*Moved to FERC 930 (Non-Labor Expenses)*					
222	907	Supervision		$ (200,527)	$ -	$ (200,527)
223	908	Customer Assistance Expenses		126	-	126
224	909	Informational & Instructional Advertising Expenses		40,210	-	40,210
225	910	Misc Customer Service & Informational Expenses		2,914	-	2,914
226	911	Supervision		-	-	-
227	912	Demonstrating & Selling Expense		2,027	-	2,027
228	913	Advertising Expense		-	-	-
229	916	Miscellaneous Sales Expense		4,585	-	4,585
230				**$ (150,664)**	**$ -**	**$ (150,664)**

Work Paper 38 - Key Accounts

Purpose: Allocation of Expenses Associated with Key Accounts to Test Year Customer Classes

Line No.		Source Reference	Key Account Time	Test Year Source Reference	Test Year Cost	Key Account Electric Allocation
A		B	C	D	E	F
1	**Key Accounts**					
2						
3	**FY 2009 Actual Cost of Key Accounts**			WP 36	**$ 1,435,057**	
4						
5	**Electric**					
6	Residential	SD-48	0.5%		$ 7,175	**0.5%**
7	Secondary Voltage < 10 kW	SD-48	9.5%		136,330	**9.9%**
8	Secondary Voltage 10 - 49.9 kW	SD-48	14.5%		208,083	**15.1%**
9	Secondary Voltage ≥ 50 kW	SD-48	45.0%		645,776	**46.9%**
10	Primary Voltage < 3 MW	SD-48	6.5%		93,279	**6.8%**
11	Primary Voltage 3 - 19.9 MW	SD-48	14.5%		208,083	**15.1%**
12	Primary Voltage ≥ 20 MW	SD-48	4.0%		57,402	**4.2%**
13	Transmission Voltage	SD-48	1.5%		21,526	**1.6%**
14	Service Area Street Lighting	SD-48	0.0%		-	**0.0%**
15	AE-Owned Private Outdoor Lighting	SD-48	0.0%		-	**0.0%**
16	Non-Metered Lighting	SD-48	0.0%		-	**0.0%**
17	Metered Lighting	SD-48	0.0%		-	**0.0%**
18	Total		96.0%		$ 1,377,654	**100.0%**
19						
20	**Non-Electric** [1]	SD-48	4.0%		$ 57,402	
21						
22			100.0%		$ 1,435,057	
23	Notes:					
24	[1] The non-electric portion is removed from the Test Year					

Work Paper 39 - Allocation Factors from T-COS

Purpose: Report Allocation Factors Used in the FY 2009 T-COS Developed by AE Staff

Line No.		Source Reference	Work Paper Reference Within Source Document	Production	Transmission	Distribution	Customer	Total
A		B	C	D	E	F	G	H
1	**Insurance Allocator**							
2	INSUR	WP 39.4		71.0%	4.4%	24.3%	0.3%	100.0%
3								
4	**Transportation Equipment Allocation**							
5	392	WP 39.3		6.9%	34.0%	59.1%	0.0%	100.0%
6								
7	**Communication Equipment Allocation**							
8	397	WP 39.1		42.9%	12.2%	24.6%	20.3%	100.0%
9								
10	**MISCELLANEOUS REV-OPER**							
11	Misc Op Rev 4874	SD-25	WP E-5	108,000	-	12,003	-	120,003
12								
13	**MISCELLANEOUS REV-NONOP**							
14	Misc Non-Op Rev 4874	SD-25	WP E-5	1,509	207	15,631	-	17,346
15								
16	**RENTALS NON OPERATING**							
17	Misc Non-Op Rev 4952	SD-25	WP E-5	20,885	-	3,343	-	24,228
18								
19	**ECCCOM Allocation Factor**							
20	ECCCOM	WP 39.2		36.4%	35.1%	28.5%	0.0%	100.0%

Work Paper 39.1 - Allocation Factors from T-COS

Purpose: Develop Allocation Factor for Communication Equipment Based on the FY 2009 T-COS Developed by AE Staff

Line No.		FY 2009 Source Reference	FY 2009 Actual	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A		B	C	D	E	F	G	H	I
1	**Communication Equipment FERC 397**								
2	CRSS	SD-49	$ 80,316	PAYXAG	$ 19,226	$ 7,654	$ 23,613	$ 29,823	$ 80,316
3	DPPP	SD-49	185,679	Production	185,679	-	-	-	185,679
4	DPPS	SD-49	73,277	Production	73,277	-	-	-	73,277
5	ECCD	SD-49	1,917,894	Distribution	-	-	1,917,894	-	1,917,894
6	ECCM	SD-49	8,726	Distribution	-	-	8,726	-	8,726
7	ECCS	SD-49	8,084,054	ECCCOM	2,942,752	2,840,101	2,301,202	-	8,084,054
8	ECCT	SD-49	12,595	Transmission	-	12,595	-	-	12,595
9	FPPS	SD-49	46,508	Production	46,508	-	-	-	46,508
10	HPPS	SD-49	11,269	Production	11,269	-	-	-	11,269
11	KRMD	SD-49	49,770	Distribution	-	-	49,770	-	49,770
12	KRMS	SD-49	239,526	PAYXAG	57,337	22,826	70,422	88,941	239,526
13	KRMT	SD-49	24,565	Transmission	-	24,565	-	-	24,565
14	SBCS	SD-49	25,482	TRAN/DIST	-	12,741	12,741	-	25,482
15	SBDD	SD-49	171,898	Distribution	-	-	171,898	-	171,898
16	SBTT	SD-49	789,507	Transmission	-	789,507	-	-	789,507
17	SEAS	SD-49	11,110	PAYXAG	2,660	1,059	3,266	4,125	11,110
18	SHEP	SD-49	1,501	Production	1,501	-	-	-	1,501
19	SHES	SD-49	20,799	Production	20,799	-	-	-	20,799
20	STED	SD-49	1,301	Distribution	-	-	1,301	-	1,301
21	STES	SD-49	207,176	PAYXAG	49,593	19,743	60,911	76,929	207,176
22	STPP	SD-49	12,398,713	Production	12,398,713	-	-	-	12,398,713
23	STPS	SD-49	-	Production	-	-	-	-	-
24	TCPC	SD-49	1,301	Distribution	-	-	1,301	-	1,301
25	TCPS	SD-49	7,696	PAYXAG	1,842	733	2,263	2,858	7,696
26	TLCQ	SD-49	396,789	PAYXAG	94,982	37,813	116,659	147,336	396,789
27	TLCS	SD-49	27,703,605	PAYXAG	6,631,581	2,640,073	8,145,045	10,286,906	27,703,605
28	811S	SD-49	44,172	PAYXAG	10,574	4,209	12,987	16,402	44,172
29	WC09	SD-49	48,266	PAYXAG	11,554	4,600	14,191	17,922	48,266
30			$ 52,563,496		$ 22,559,845	$ 6,418,220	$ 12,914,189	$ 10,671,242	$ 52,563,496
31									
32					**42.9%**	**12.2%**	**24.6%**	**20.3%**	**100.0%**

Work Paper 39.2 - Allocation Factors from T-COS

Purpose: Develop Allocation Factor for ECC Communication Equipment Based on the FY 2009 T-COS Developed by AE Staff

Line No.	FERC Account		FY 2009 Source Reference	FY 2009 Actual	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A	B		C	D	E	F	G	H	I	J
1	**ECC Communication Equipment**									
2	556	System Control and Load Dispatching	SD-49	$ 1,586,738	Production	$ 1,586,738	$ -	$ -	$ -	$ 1,586,738
3	561	Load Dispatching	SD-49	1,531,389	Transmission	-	1,531,389	-	-	1,531,389
4	581	Load Dispatching	SD-49	1,240,813	Distribution	-	-	1,240,813	-	1,240,813
5				$ 4,358,940		$ 1,586,738	$ 1,531,389	$ 1,240,813	$ -	$ 4,358,940
6										
7						**36.4%**	**35.1%**	**28.5%**	**0.0%**	**100.0%**

Work Paper 39.3 - Allocation Factors from T-COS

Purpose: Develop Allocation Factor for FERC 392 Based on the FY 2009 T-COS Developed by AE Staff

Line No.		FY 2009 Source Reference	FY 2009 Actual	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A		C	D	E	F	G	H	I	J
1	**Transportation Equipment FERC 392**								
2	Transportation Equipment - GENERATION	SD-49	$ 1,622,634	Production	$ 1,622,634	$ -	$ -	$ -	$ 1,622,634
3	Transportation Equipment - TRANSMISSION	SD-49	8,031,406	Transmission	-	8,031,406	-	-	8,031,406
4	Transportation Equipment - DISTRIBUTION	SD-49	13,965,191	Distribution	-	-	13,965,191	-	13,965,191
5			$ 23,619,231		$ 1,622,634	$ 8,031,406	$ 13,965,191	$ -	$ 23,619,231
6									
7					**6.9%**	**34.0%**	**59.1%**	**0.0%**	**100.0%**
8									
9	Transportation Equipment - Pro-rate Remainder	SD-49	$ 3,304,271		$ 227,002	$ 1,123,573	$ 1,953,695	$ -	$ 3,304,271
10									
11			$ 26,923,502		$ 1,849,636	$ 9,154,980	$ 15,918,886	$ -	$ 26,923,502
12									
13					**6.9%**	**34.0%**	**59.1%**	**0.0%**	**100.0%**

Work Paper 39.4 - Allocation Factors from T-COS

Purpose: Develop Allocation Factor for Insurance Based on the FY 2009 T-COS Developed by AE Staff

Line No.				Source Reference	Estimated Electric Property Value	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A				B	C	D	E	F	G	H	I
1	**All Risk Insurance**										
2	Decker Creek Power Plant	Decker Ck Rd	Power Plant	SD-49	$ 650,969,022	Production	$ 650,969,022	$ -	$ -	$ -	$ 650,969,022
3	Holly Street Station	2400 Holly St	Power Plant	SD-49	34,039,200	Production	34,039,200	-	-	-	34,039,200
4	Sandhill Power Plant	13005 Fallwell Ln.	Power Plant	SD-49	312,014,755	Production	312,014,755	-	-	-	312,014,755
5	Kramer Lane Service Center	2412 Kramer Ln	Buildings	SD-49	12,032,135	SQFT	5,238,016	1,282,954	4,635,111	876,054	12,032,135
6	St. Elmo Service Center	4411 Meindarus	Buildings	SD-49	8,021,423	SQFT	3,492,011	855,303	3,090,074	584,036	8,021,423
7	Backup Control Center	Decker Creek Rd.	Monitor Station	SD-49	627,192	SQFT	273,039	66,876	241,612	45,666	627,192
8	Main Control Center	301West Ave	Monitor Station	SD-49	15,374,395	SQFT	6,693,021	1,639,330	5,922,641	1,119,403	15,374,395
9	New Control Center (Tokyo Electron)	2510 Grove Blvd	Monitor Station	SD-49	27,768,000	SQFT	12,088,398	2,960,827	10,697,000	2,021,775	27,768,000
10	AMD Distribution Substation	5204 E Ben White	Substation	SD-49	1,336,400	Transmission	-	1,336,400	-	-	1,336,400
11	Angus Valley Distribution Substation	6509 Yaupon Drive	Substation	SD-49	3,515,200	Distribution	-	-	3,515,200	-	3,515,200
12	Austin Dam Distribution Substation	3617 Lake Austin Blvd	Substation	SD-49	3,539,120	Distribution	-	-	3,539,120	-	3,539,120
13	Austrop Transmission Substation	Black & Manor Rd	Substation	SD-49	13,759,200	Transmission	-	13,759,200	-	-	13,759,200
14	Balcones Substation	3300 Braker Lane	Substation	SD-49	2,822,560	Distribution	-	-	2,822,560	-	2,822,560
15	Barton Distribution Substation	2002 Loop 360	Substation	SD-49	6,897,280	Distribution	-	-	6,897,280	-	6,897,280
16	Bee Creek Distribution Substation	3602 Red Bud Tl	Substation	SD-49	5,224,960	Distribution	-	-	5,224,960	-	5,224,960
17	Bergstrom Distribution Substation	1800 Bastrop Hwy	Substation	SD-49	3,921,840	Distribution	-	-	3,921,840	-	3,921,840
18	Bluestein Distribution Substation	3501 Ed Bluestein	Substation	SD-49	7,876,960	Distribution	-	-	7,876,960	-	7,876,960
19	Brackenridge Distrib Substation	1300 IH 35	Substation	SD-49	5,125,120	Distribution	-	-	5,125,120	-	5,125,120
20	Brodie Lane Substation	9612 Brodie Lane	Substation	SD-49	5,125,120	Distribution	-	-	5,125,120	-	5,125,120
21	Burleson Trans Distrib Substation	3700 Todd Lane	Substation	SD-49	6,154,720	Distribution	-	-	6,154,720	-	6,154,720
22	Cameron Distribution Substation	1312 Rutherford Ln	Substation	SD-49	6,632,120	Distribution	-	-	6,632,120	-	6,632,120
23	Cardinal Ln Distribution Substation	818 Cardinal Ln	Substation	SD-49	7,336,160	Distribution	-	-	7,336,160	-	7,336,160
24	Carson Ck Distribution Substation	3310 McCall Ln	Substation	SD-49	3,552,640	Distribution	-	-	3,552,640	-	3,552,640
25	Central Austin Substation	909 W. 45th	Substation	SD-49	4,117,360	Distribution	-	-	4,117,360	-	4,117,360
26	Commons Ford Distrib Substation	115 River Hills Rd	Substation	SD-49	5,233,280	Distribution	-	-	5,233,280	-	5,233,280
27	Daffin Gin Distribution Substation	8317 Decker Ln	Substation	SD-49	3,582,800	Distribution	-	-	3,582,800	-	3,582,800
28	Decker Plant Trans Substation	8003 Decker Ln	Substation	SD-49	5,357,440	Transmission	-	5,357,440	-	-	5,357,440
29	Dessau Substation	3200 E. Yeager Lane	Substation	SD-49	15,556,960	Distribution	-	-	15,556,960	-	15,556,960
30	Fiesta Substation	3909 N. IH35	Substation	SD-49	8,524,453	Distribution	-	-	8,524,453	-	8,524,453
31	Fiskville Distribution Substation	9800 Mid Fiskville	Substation	SD-49	3,748,160	Distribution	-	-	3,748,160	-	3,748,160
32	Garfield Transmission Substation	Elm Ridge Road	Substation	SD-49	13,370,240	Transmission	-	13,370,240	-	-	13,370,240
33	Grove Distribution Substation	2706 Montopolis	Substation	SD-49	5,286,320	Distribution	-	-	5,286,320	-	5,286,320
34	Hamilton Distribution Substation	4603 Hamilton Road	Substation	SD-49	7,136,480	Distribution	-	-	7,136,480	-	7,136,480
35	Harris Distribution Substation	302 E. 24th	Substation	SD-49	7,280,000	Distribution	-	-	7,280,000	-	7,280,000
36	Hi-Cross Distribution Substation	6714 Bluff Springs	Substation	SD-49	7,329,920	Distribution	-	-	7,329,920	-	7,329,920
37	Hidden Valley Substation	4501 N. FM620, Bldg G	Substation	SD-49	3,879,000	Distribution	-	-	3,879,000	-	3,879,000
38	Holly Plant Trans Substation	2401 Holly St	Substation	SD-49	2,711,280	Transmission	-	2,711,280	-	-	2,711,280
39	Holman Transmission Substation	Fayette Co Rd 1383	Substation	SD-49	1,446,640	Transmission	-	1,446,640	-	-	1,446,640
40	Howard Lane Distribution	2305 Gardenia St.	Substation	SD-49	3,810,560	Distribution	-	-	3,810,560	-	3,810,560
41	Jett Distribution Substation	6622 Vaught Ranch Rd	Substation	SD-49	3,539,120	Distribution	-	-	3,539,120	-	3,539,120
42	Jollyville Distribution Substation	13175 Rutledge Spur	Substation	SD-49	5,338,320	Distribution	-	-	5,338,320	-	5,338,320
43	Justin Distribution Substation	7520 North Lamar	Substation	SD-49	3,881,000	Distribution	-	-	3,881,000	-	3,881,000
44	Kingsbery Trans Distrib Substation	5001 Alf Ave.	Substation	SD-49	7,930,000	Distribution	-	-	7,930,000	-	7,930,000
45	Koenig Lane Distrib Substation	905 W Koenig Ln	Substation	SD-49	-	Distribution	-	-	-	-	-
46	Lakeshore Distrib Substation	3106 West Lake Dr	Substation	SD-49	3,595,280	Distribution	-	-	3,595,280	-	3,595,280

Work Paper 39.4 - Allocation Factors from T-COS

Purpose: Develop Allocation Factor for Insurance Based on the FY 2009 T-COS Developed by AE Staff

Line No.				Source Reference	Estimated Electric Property Value	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A				B	C	D	E	F	G	H	I
47	Lakeway Distribution Substation	15310 Kollmeyer Dr	Substation	SD-49	3,350,880	Distribution	-	-	3,350,880	-	3,350,880
48	Lost Pines	Highway 21, Bastrop	Substation	SD-49	2,510,560	Transmission	-	2,510,560	-	-	2,510,560
49	Lytton Springs Trans Substation	Caldwell Co. Rd. 177	Substation	SD-49	12,810,840	Transmission	-	12,810,840	-	-	12,810,840
50	Magnesium Distrib Substation	8914 Research	Substation	SD-49	5,472,480	Distribution	-	-	5,472,480	-	5,472,480
51	McNeil Trans Distrib Substation	11900 Knollpark Dr	Substation	SD-49	11,848,720	Distribution	-	-	11,848,720	-	11,848,720
52	Met Center	7315 Metro Center	Substation	SD-49	2,497,040	Distribution	-	-	2,497,040	-	2,497,040
53	Northland Trans Distrib Substation	3101 Northland	Substation	SD-49	10,775,440	Distribution	-	-	10,775,440	-	10,775,440
54	Northwest Substation	8400 W. Parmer Ln	Substation	SD-49	2,327,520	Distribution	-	-	2,327,520	-	2,327,520
55	Oakhill Distribution Substation	5915 McCarty Ln	Substation	SD-49	5,288,400	Distribution	-	-	5,288,400	-	5,288,400
56	Onion Ck Distribution Substation	12705 Fallwell Ln	Substation	SD-49	4,819,360	Distribution	-	-	4,819,360	-	4,819,360
57	Patton Ln Distribution Substation	6501 W Wm Cannon	Substation	SD-49	8,238,880	Distribution	-	-	8,238,880	-	8,238,880
58	Pedernales Ln Distrib Substation	2401 Holly St	Substation	SD-49	24,170,640	Distribution	-	-	24,170,640	-	24,170,640
59	Pilot Knob Trans Substation	9908 FM 812	Substation	SD-49	1,075,360	Transmission	-	1,075,360	-	-	1,075,360
60	Riverplace Distrib Substation	10712 RM 2222	Substation	SD-49	3,892,720	Distribution	-	-	3,892,720	-	3,892,720
61	Salem Walk Distrib Substation	5300 Salem Hills Dr	Substation	SD-49	5,372,640	Distribution	-	-	5,372,640	-	5,372,640
62	Sandhill Substation	13005 Fallwell Ln.	Switch Yard	SD-49	2,295,280	Transmission	-	2,295,280	-	-	2,295,280
63	Seaholm Plant Distrib Substation	800 W Cesar Chavez	Substation	SD-49	13,474,920	Distribution	-	-	13,474,920	-	13,474,920
64	Slaughter Ln Distrib Substation	1111 Slaughter Ln	Substation	SD-49	5,151,120	Distribution	-	-	5,151,120	-	5,151,120
65	Sprinkle Distribution Substation	10600 Cameron Rd	Substation	SD-49	3,612,960	Distribution	-	-	3,612,960	-	3,612,960
66	Steck Distribution Substation	3419 Steck Ave	Substation	SD-49	4,929,600	Distribution	-	-	4,929,600	-	4,929,600
67	Summit Distrib Substation	11300 Burnet Rd.	Substation	SD-49	9,002,240	Distribution	-	-	9,002,240	-	9,002,240
68	Tech Ridge	905 W. Howard Lane	Substation	SD-49	5,182,320	Distribution	-	-	5,182,320	-	5,182,320
69	Trading Post	14500 Highway 71 West	Substation	SD-49	3,908,320	Distribution	-	-	3,908,320	-	3,908,320
70	Vega Substation	6501 W. William Cannon	Substation	SD-49	2,418,000	Distribution	-	-	2,418,000	-	2,418,000
71	Walnut Ck Distrib Substation	7401 FM 969	Substation	SD-49	3,875,040	Distribution	-	-	3,875,040	-	3,875,040
72	Warren Distribution Substation	2100 W 35th	Substation	SD-49	3,467,360	Distribution	-	-	3,467,360	-	3,467,360
73	Wells Branch Substation	14608 1/2 Single Trace	Substation	SD-49	3,940,560	Distribution	-	-	3,940,560	-	3,940,560
74	Wheless Ln Distrib Substation	2100 Wheless Ln	Substation	SD-49	5,061,680	Distribution	-	-	5,061,680	-	5,061,680
75	Williamson Distrib Substation	6505 McNeil Dr.	Substation	SD-49	7,111,520	Distribution	-	-	7,111,520	-	7,111,520
76	Zilker Distribution Substation	423 Dawson	Substation	SD-49	1,962,480	Distribution	-	-	1,962,480	-	1,962,480
77	Dell Children's Hospital	4901 Lancaster Dr.	Power Plant	SD-49	8,297,143	Production	8,297,143	-	-	-	8,297,143
78	Dell Children's Hospital	4901 Lancaster Dr.	Chiller Plant	SD-49	-		-	-	-	-	-
79	District Cooling Center #1 (Hobby)	300 San Antonio	Chiller Plant	SD-49	-		-	-	-	-	-
80	District Cooling Center #2	410 Sabine	Chiller Plant	SD-49	-		-	-	-	-	-
81	Domain Chiller Plant	Braker Lane	Chiller Plant	SD-49	-		-	-	-	-	-
82					$ 1,454,462,159		$ 1,033,104,606	$ 63,478,529	$ 353,232,090	$ 4,646,934	$ 1,454,462,159
83											
84							**71.0%**	**4.4%**	**24.3%**	**0.3%**	**100.0%**

Work Paper 40 - Rate Case Expenses

Purpose: Identification of Rate Case Expenses for Amortization in the Test Year

Line No.		Source Reference	FERC Account	Total Expense	Test Year
A		B	C	D	E
1	**Rate Case Expenses**				
2	Rate Consultant - A & B	SD-70		$ 2,000,000	
3	Residential Rate Advisor	SD-50		90,000	
4	Rate Consultant - C	SD-70		1,000,000	
5	Website Development	SD-50		102,138	
6	Rate Benchmarking	SD-50		101,400	
7	Navigant Research	SD-50		285,183	
8	Outside Legal Council	SD-50		300,000	
9				$ 3,878,720	
10					
11	**Recovery Period (years)**			3	
12					
13	**Test Year Rate Case Expense**		928		**$ 1,292,907**
14					

Work Paper 41 - Production Capacity

Purpose: Identify the Capacities of Non-Nuclear Generating Facilities

Line No.		Source Reference	Name Plate Capacity (MW)	Net Dependable Capacity (MW)	Gross Dependable Capacity (MW)	Fuel Type	Average Heat Rate (BTU/kWh)
A		B	C	D	E	F	G
1	**Decker Power Plant**						
2	Plant Unit 1	SD-51	321	310	317	Natural Gas / Fuel Oil	
3	Plant Unit 2	SD-51	405	420	432	Natural Gas / Fuel Oil	
4	Plant Gas Turbine 1	SD-51	50	50	52	Natural Gas / Fuel Oil	
5	Plant Gas Turbine 2	SD-51	50	50	52	Natural Gas / Fuel Oil	
6	Plant Gas Turbine 3	SD-51	50	50	52	Natural Gas / Fuel Oil	
7	Plant Gas Turbine 4	SD-51	50	50	52	Natural Gas / Fuel Oil	
8			926	930	957		77,233
9							
10	**Sand Hill Energy Center**						
11	Gas Turbine 1	SD-51	45	45	47	Natural Gas	
12	Gas Turbine 2	SD-51	45	45	47	Natural Gas	
13	Gas Turbine 3	SD-51	45	45	47	Natural Gas	
14	Gas Turbine 4	SD-51	45	45	47	Natural Gas	
15	Gas Turbine 6	SD-51	45	45	47	Natural Gas	
16	Gas Turbine 7	SD-51	45	45	47	Natural Gas	
17	Combined Cycle 5A & 5C	SD-51	300	295	305	Natural Gas	
18			570	565	587		74,809
19							
20	**Fayette Power Plant**						
21	Unit 1	SD-64	300			Coal	
22	Unit 2	SD-64	300			Coal	
23			600	-	-		

Work Paper 41 - Production Capacity

Line No.		Dispatch Classification	Decker and SHEC Name Plate Capacity Base	Intermediate	Peak	Total
A		H	I	J	K	L
1	**Decker Power Plant**					
2	Plant Unit 1	Intermediate	-	321	-	321
3	Plant Unit 2	Intermediate	-	405	-	405
4	Plant Gas Turbine 1	Peak	-	-	50	50
5	Plant Gas Turbine 2	Peak	-	-	50	50
6	Plant Gas Turbine 3	Peak	-	-	50	50
7	Plant Gas Turbine 4	Peak	-	-	50	50
8			-	726	200	926
9						
10	**Sand Hill Energy Center**					
11	Gas Turbine 1	Peak	-	-	45	45
12	Gas Turbine 2	Peak	-	-	45	45
13	Gas Turbine 3	Peak	-	-	45	45
14	Gas Turbine 4	Peak	-	-	45	45
15	Gas Turbine 6	Peak	-	-	45	45
16	Gas Turbine 7	Peak	-	-	45	45
17	Combined Cycle 5A & 5C	Intermediate	-	300	-	300
18			-	300	270	570
19						
20	**Fayette Power Plant**					
21	Unit 1					
22	Unit 2					
23						

Work Paper 42 - Legislative Advocacy and Property Insurance

Purpose: Identification of Costs Associated with Legislative Advocacy and Non-Electric Property Insurance for Removal from Test Year

Line No.		FERC Account	FY 2009 Source Reference	Adjustment Source Reference	FY 2009 Actual	Adjustment	Test Year	Total Adjustment
A		B	C	D	E	F	G	H
1	**Legislative Advocacy**							
2	Miscellaneous Sales Expense	916	WP 1	SD-52	$ 452,925	(110,000)	$ 342,925	$ (110,000)
3	Outside Services Employed	923	WP 1	SD-52	10,565,986	(145,689)	10,420,298	(145,689)
4	General Expenses	930	WP 1	SD-52	22,428,040	(58,553)	22,369,487	(58,553)
5					$ 33,446,951		$ 33,132,709	$ (314,242)
6								
7	**Property Insurance** [1]							
8	Property Insurance	924	WP 1	SD-17	$ 683,345	(120,869)	$ 562,476	$ (120,869)
9					$ 683,345		$ 562,476	$ (120,869)
10								
11	Notes:							
12	[1] Amount identified as a non-electric expense in the FY 2009 T-COS Trial Balance							

Work Paper 43 - Amortization

Purpose: Functionalization of Amortization of Contribution in Aid to Construction in FY 2009

Line No.		Source Reference	Total Electric	Allocation Basis	Production	Transmission	Distribution	Customer	Total
A		B	C	D	E	F	G	H	I
1	**Contribution in Aid to Construction**								
2	2548 DCIAC AMD	SD-53	$ (22,415)	Transmission	$ -	$ (22,415)	$ -	$ -	$ (22,415)
3	All Other CIAC	SD-53	(5,158,416)	Distribution	-	-	(5,158,416)	-	(5,158,416)
4			$ (5,180,831)		$ -	$ (22,415)	$ (5,158,416)	$ -	$ (5,180,831)

Work Paper 44 - Production Cost Run

Purpose: Identify Generation by Unit at Each Facility as well as the Associated Fuel and Purchase Power Costs in the Test Year

Line No.	Unit	FY 2009 MWh Source Reference	FY 2009 Fuel Source Reference	Test Year MWh Source Reference	Test Year Fuel Source Reference	MWh FY 2009 Actual	MWh Test Year	Fuel Expense FY 2009 Actual	Fuel Expense Test Year
A	B	C	D	E	F	G	H	I	J
1	**Recoverable Fuel and Purchased Power**								
2	**Fuel**								
3	**South Texas Project**								
4	**Nuclear - Base Load**								
5	Unit 1	SD-60	SD-8	SD-62	SD-54			$ -	$ -
6	Unit 2	SD-60	SD-8	SD-62	SD-54			-	-
7	Combined	SD-60	SD-8	SD-62	SD-54	-	-	16,866,183	19,347,060
8						3,512,636	3,413,161	$ 16,866,183	$ 19,347,060
9									
10	**Fayette Power Plant**								
11	**Coal - Base Load**								
12	Unit 1	SD-60	SD-8	SD-62	SD-54			$ -	$ -
13	Unit 2	SD-60	SD-8	SD-62	SD-54			-	-
14	Combined	SD-60	SD-8	SD-62	SD-54	-	-	85,200,396	109,552,730
15						3,756,777	4,474,090	$ 85,200,396	$ 109,552,730
16									
17	**Decker Creek Power Station**								
18	**Gas Steam Boiler - Intermediate**								
19	Unit 1	SD-60	SD-8	SD-62	SD-54			$ -	$
20	Unit 2	SD-60	SD-8	SD-62	SD-54			-	
21	Combined	SD-60	SD-8	SD-62	SD-54	-	-	81,342,241	-
22						1,657,216	315,809	$ 81,342,241	$ 21,976,759
23									
24	**Gas Combustion Turbine - Peak**								
25	GT 1	SD-60	SD-8	SD-62	SD-54			$ -	$
26	GT 2	SD-60	SD-8	SD-62	SD-54			-	
27	GT 3	SD-60	SD-8	SD-62	SD-54			-	
28	GT 4	SD-60	SD-8	SD-62	SD-54			-	
29	Combined	SD-60	SD-8	SD-62	SD-54	-	-	12,341,673	-
30						62,672	6,321	$ 12,341,673	$ 439,855
31									
32						1,719,888	322,130	$ 93,683,914	$ 22,416,614
33									
34	**Sand Hill Energy Center**								
35	**Gas Combustion Turbine - Peak**								
36	GT 1	SD-60	SD-8	SD-62	SD-54				
37	GT 2	SD-60	SD-8	SD-62	SD-54			-	1,532,338
38	GT 3	SD-60	SD-8	SD-62	SD-54				
39	GT 4	SD-60	SD-8	SD-62	SD-54				
40	GT 6	SD-60	SD-8	SD-62	SD-54				
41	GT 7	SD-60	SD-8	SD-62	SD-54				
42	Combined	SD-60	SD-8	SD-62	SD-54	-	-	5,572,283	-
43						187,191	139,038	$ 5,572,283	$ 9,675,502
44									
45	**Gas Combined Cycle - Intermediate**								
46	CC 5A	SD-60	SD-8	SD-62	SD-54				
47	CC 5C	SD-60	SD-8	SD-62	SD-54				
48	Combined	SD-60	SD-8	SD-62	SD-54	-	1,613,964	115,457,373	112,313,809
49						1,616,778	1,613,964	$ 115,457,373	$ 112,313,809
50									
51						1,803,969	1,753,002	$ 121,029,656	$ 121,989,311
52									
53	**Total Fuel**					**10,793,270**	**9,962,382**	**$ 316,780,149**	**$ 273,305,715**
54									
55	**Purchased Power**								
56	**Purchased Power**								
57	Purchased Power (FERC 555)		SD-8		SD-54			$ 54,863,996	$ 23,084,089
58	ERCOT Recoverable (FERC 556)		WP 28		SD-54 & WP 28.1			12,791,041	21,079,958
59								$ 67,655,037	$ 44,164,047
60									
61	**Renewable (FERC 555)**								
62	Green Choice (paid for by non-GC customers)		SD-8					$ 23,966,180	$ -
63	Wind				SD-54			-	68,685,270
64	Landfill Methane				SD-54			-	3,322,545
65	Solar				SD-54			-	11,477,080
66	Billed Green Choice							-	(10,057,082)
67								$ 23,966,180	$ 73,427,813
68									
69	**Total Purchased Power**							**$ 91,621,217**	**$ 117,591,860**
70									
71	**Total Fuel and Purchased Power (before adjustments)**							**$ 408,401,366**	**$ 390,897,575**
72	**Adjustments**								
73	Off System Sales Fuel		SD-18					$ (21,657,426)	$ -
74								$ (21,657,426)	$ -
75									
76	**Total Recoverable Fuel and Purchased Power (after adjustments)**							**$ 386,743,940**	**$ 390,897,575**

Work Paper 44 - Production Cost Run

Purpose: Identify Generation by Unit at Each Facility as well as the Associated Fuel and Purchase Power Costs in the Test Year

		FY 2009		Test Year		MWh		Fuel Expense	
Line No.	Unit	MWh Source Reference	Fuel Source Reference	MWh Source Reference	Fuel Source Reference	FY 2009 Actual	Test Year	FY 2009 Actual	Test Year
A	B	C	D	E	F	G	H	I	J
77									
78	**Billed Green Choice**								
79	Green Choice (FERC 555)		SD-8		WP 44.1			$ 26,510,687	$ 10,057,082
80	Green Choice (FERC 556)		SD-8					8,189,149	-
81								$ 34,699,836	$ 10,057,082
82									
83	**Non-Recoverable Fuel**								
84	Coal Handling (FERC 501)		SD-8		FY 2009 Actual			$ 3,731,980	$ 3,731,980
85	Payroll (FERC 501)		SD-8		FY 2009 Actual			351,564	351,564
86	Utilities - Electric Services (FERC 555)		SD-8		FY 2009 Actual			346,133	346,133
87	Payroll, Benefits & Other (FERC 556)		SD-8		WP 28			1,732,634	1,732,634
88								$ 6,162,310	$ 6,162,310
89									
90	**Total Billed Green Choice and Non-Recoverable Fuel**							**$ 40,862,146**	**$ 16,219,392**
91									
92	**Total Fuel Related Costs**							**$ 427,606,086**	**$ 407,116,968**
93									
94									
95	**Renewable Generation Detail**								
96	**Wind**								
97	LCRA_AE			SD-62			35,901		$ -
98	SW2_AE			SD-62			333,597		-
99	SW3_AE			SD-62			127,459		-
100	Whirlwind			SD-62			89,710		-
101	Hackberry			SD-62			298,646		-
102	2011 Wind			SD-62					
103	Combined				SD-54		-		68,685,270
104							1,722,243		$ 68,685,270
105									
106	**Wind Average Cost per MWh**								$ 39.88
107									
108	**Solar**								
109	Webberville and Existing Solar			SD-62	SD-54		69,769		$ 11,477,080
110							69,769		$ 11,477,080
111									
112	**Solar Average Cost per MWh**								$ 164.50
113									
114	**Landfill Methane**								
115	Sunset			SD-62			29,189		$ -
116	TESSMANRD			SD-62			56,474		-
117	Combined				SD-54		-		3,322,545
118							85,663		$ 3,322,545
119									
120	**Landfill Methane Average Cost per MWh**								$ 38.79
121									
122	**Total Renewable Generation**						1,877,675		$ 83,484,895
123									
124	**Renewable Average Cost per MWh**								$ 44.46
125									
126	**Total Generation MWh**						**11,840,058**		
127									
128	Notes:								
129									

Austin Energy
Electric Cost of Service

Work Paper 44.1 - Production Cost Run

Purpose: Summarize the Green Choice Billing Units in the Test Year and Develop an Estimate of NEFL Associated with Green Choice Sales

Line No.		Test Year Green Choice Source Reference	Test Year Green Choice kWh Sales	Test Year Green Choice Billed Revenue	Line Loss Source Reference	Line Loss by Service Level (%)	Line Loss by Service Level (kWh)	Estimated Green Choice NEFL
A		B	C	D	E	F	G	H
1	**Green Choice**							
2	**Normalized Test Year**							
3	Residential	WP 44.2	54,762,351	$ 2,384,764	WP 23	5.05%	2,913,243	57,675,594
4	Secondary Voltage < 10 kW	WP 44.2	9,269,558	375,868	WP 23	5.05%	493,121	9,762,679
5	Secondary Voltage 10 - 49.9 kW	WP 44.2	27,628,167	1,092,030	WP 23	5.05%	1,469,761	29,097,928
6	Secondary Voltage ≥ 50 kW	WP 44.2	152,058,278	5,908,653	WP 23	5.05%	8,089,184	160,147,462
7	Primary Voltage < 3 MW	WP 44.2	8,933,972	294,821	WP 23	2.85%	262,096	9,196,068
8	Primary Voltage 3 - 19.9 MW	WP 44.2	-	-	WP 23	2.85%	-	-
9	Primary Voltage ≥ 20 MW	WP 44.2	-	-	WP 23	2.85%	-	-
10	Transmission Voltage		-	-	WP 23	1.60%	-	-
11	Service Area Street Lighting	WP 44.2	-	-	WP 23	5.05%	-	-
12	AE-Owned Private Outdoor Lighting	WP 44.2	-	-	WP 23	5.05%	-	-
13	Non-Metered Lighting	WP 44.2	-	-	WP 23	5.05%	-	-
14	Metered Lighting	WP 44.2	28,192	946	WP 23	5.05%	1,500	29,692
15			252,680,519	$ 10,057,082			13,228,905	265,909,424

Work Paper 44.2 - Production Cost Run

Purpose: Identify the Green Choice kWh and Revenue in the Test Year

Line No.		Source Reference	Rate Code	Batch 1	Batch 2	Batch 3	Batch 4	Batch 5	Batch 6 5-Year	Batch 6 10-Year	Batch 6.3	Total	Expired Batch 1 & 2	Test Year Net of Batch 1 & 2
A		B	C	D	E	F	G	H	I	J	K	L	M	N
1	**Green Choice kWh (Normalized FY 2009)**													
2	**Residential**													
3		SD-31	GC01	17,958,466	-	-	-	-	-	-	-	17,958,466	17,958,466	**-**
4		SD-31	GC07	-	40,330,148	-	-	-	-	-	-	40,330,148	40,330,148	**-**
5		SD-31	GC14	-	-	10,269,453	-	-	-	-	-	10,269,453	-	**10,269,453**
6		SD-31	GC21	-	-	-	20,813,173	-	-	-	-	20,813,173	-	**20,813,173**
7		SD-31	GC31	-	-	-	-	23,000,515	-	-	-	23,000,515	-	**23,000,515**
8		SD-31	GC35	-	-	-	-	-	439,841	-	-	439,841	-	**439,841**
9		SD-31	GC38	-	-	-	-	-	-	93,460	-	93,460	-	**93,460**
10		SD-31	GC45	-	-	-	-	-	-	-	145,908	145,908	-	**145,908**
11	Subtotal			17,958,466	40,330,148	10,269,453	20,813,173	23,000,515	439,841	93,460	145,908	113,050,965	58,288,614	**54,762,351**
12	**Secondary Voltage (< 10 kW)**													
13		SD-31	GC02	481,742	-	-	-	-	-	-	-	481,742	481,742	**-**
14		SD-31	GC06	-	2,830,129	-	-	-	-	-	-	2,830,129	2,830,129	**-**
15		SD-31	GC10	-	-	-	-	-	-	-	-	-	-	**-**
16		SD-31	GC11	-	17,746	-	-	-	-	-	-	17,746	17,746	**-**
17		SD-31	GC15	-	-	1,943,141	-	-	-	-	-	1,943,141	-	**1,943,141**
18		SD-31	GC19	-	-	284,680	-	-	-	-	-	284,680	-	**284,680**
19		SD-31	GC20	-	-	8,755	-	-	-	-	-	8,755	-	**8,755**
20		SD-31	GC22	-	-	-	28,489	-	-	-	-	28,489	-	**28,489**
21		SD-31	GC23	-	-	-	1,544,453	-	-	-	-	1,544,453	-	**1,544,453**
22		SD-31	GC25	-	-	-	3,361,920	-	-	-	-	3,361,920	-	**3,361,920**
23		SD-31	GC27	-	-	-	14,534	-	-	-	-	14,534	-	**14,534**
24		SD-31	GC32	-	-	-	-	4,545	-	-	-	4,545	-	**4,545**
25		SD-31	GC33	-	-	-	-	1,399,752	-	-	-	1,399,752	-	**1,399,752**
26		SD-31	GC36	-	-	-	-	-	24,145	-	-	24,145	-	**24,145**
27		SD-31	GC39	-	-	-	-	-	-	10,254	-	10,254	-	**10,254**
28		SD-31	GC41	-	-	-	-	-	518,755	-	-	518,755	-	**518,755**
29		SD-31	GC44	-	-	-	-	-	-	-	-	-	-	**-**
30		SD-31	GC46	-	-	-	-	-	-	-	8,551	8,551	-	**8,551**
31		SD-31	GC47	-	-	-	-	-	-	-	-	-	-	**-**
32		SD-31	GC48	-	-	-	-	-	-	-	117,583	117,583	-	**117,583**
33	Subtotal			481,742	2,847,875	2,236,576	4,949,396	1,404,297	542,900	10,254	126,135	12,599,174	3,329,617	**9,269,558**
34	**Secondary Voltage (≥ 10 < 50 kW)**													
35		SD-31	GC02	161,446	-	-	-	-	-	-	-	161,446	161,446	**-**
36		SD-31	GC03	67,161	-	-	-	-	-	-	-	67,161	67,161	**-**
37		SD-31	GC04	-	-	-	-	-	-	-	-	-	-	**-**
38		SD-31	GC06	-	948,460	-	-	-	-	-	-	948,460	948,460	**-**
39		SD-31	GC09	-	6,311,319	-	-	-	-	-	-	6,311,319	6,311,319	**-**
40		SD-31	GC10	-	-	-	-	-	-	-	-	-	-	**-**
41		SD-31	GC11	-	593,863	-	-	-	-	-	-	593,863	593,863	**-**
42		SD-31	GC15	-	-	651,204	-	-	-	-	-	651,204	-	**651,204**
43		SD-31	GC16	-	-	5,223,358	-	-	-	-	-	5,223,358	-	**5,223,358**
44		SD-31	GC17N	-	-	197,605	-	-	-	-	-	197,605	-	**197,605**
45		SD-31	GC17P	-	-	-	-	-	-	-	-	-	-	**-**
46		SD-31	GC19	-	-	558,686	-	-	-	-	-	558,686	-	**558,686**
47		SD-31	GC20	-	-	292,979	-	-	-	-	-	292,979	-	**292,979**
48		SD-31	GC22	-	-	-	953,375	-	-	-	-	953,375	-	**953,375**
49		SD-31	GC23	-	-	-	517,592	-	-	-	-	517,592	-	**517,592**
50		SD-31	GC24	-	-	-	7,409,208	-	-	-	-	7,409,208	-	**7,409,208**
51		SD-31	GC25	-	-	-	6,597,797	-	-	-	-	6,597,797	-	**6,597,797**
52		SD-31	GC27	-	-	-	14,568	-	-	-	-	14,568	-	**14,568**
53		SD-31	GC28	-	-	-	264,302	-	-	-	-	264,302	-	**264,302**
54		SD-31	GC32	-	-	-	-	152,104	-	-	-	152,104	-	**152,104**

Work Paper 44.2 - Production Cost Run

Purpose: Identify the Green Choice kWh and Revenue in the Test Year

Line No.		Source Reference	Rate Code	Batch 1	Batch 2	Batch 3	Batch 4	Batch 5	Batch 6 5-Year	Batch 6 10-Year	Batch 6 Batch 6.3	Total	Expired Batch 1 & 2	Test Year Net of Batch 1 & 2
A		B	C	D	E	F	G	H	I	J	K	L	M	N
55		SD-31	GC33	-	-	-	-	469,098	-	-	-	469,098	-	**469,098**
56		SD-31	GC34	-	-	-	-	2,411,833	-	-	-	2,411,833	-	**2,411,833**
57		SD-31	GC36	-	-	-	-	-	8,092	-	-	8,092	-	**8,092**
58		SD-31	GC37	-	-	-	-	-	320,075	-	-	320,075	-	**320,075**
59		SD-31	GC39	-	-	-	-	-	-	3,437	-	3,437	-	**3,437**
60		SD-31	GC40	-	-	-	-	-	-	-	-	-	-	**-**
61		SD-31	GC41	-	-	-	-	-	1,018,060	-	-	1,018,060	-	**1,018,060**
62		SD-31	GC44	-	-	-	-	-	218,226	-	-	218,226	-	**218,226**
63		SD-31	GC46	-	-	-	-	-	-	-	2,866	2,866	-	**2,866**
64		SD-31	GC47	-	-	-	-	-	-	-	48,486	48,486	-	**48,486**
65		SD-31	GC48	-	-	-	-	-	-	-	230,758	230,758	-	**230,758**
66		SD-31	GC49	-	-	-	-	-	-	-	64,458	64,458	-	**64,458**
67	Subtotal			228,607	7,853,642	6,923,833	15,756,842	3,033,035	1,564,453	3,437	346,568	35,710,416	8,082,249	**27,628,167**
68	**Secondary Voltage (≥ 50 kW)**													
69		SD-31	GC03	256,912	-	-	-	-	-	-	-	256,912	256,912	**-**
70		SD-31	GC04	-	-	-	-	-	-	-	-	-	-	**-**
71		SD-31	GC09	-	24,142,961	-	-	-	-	-	-	24,142,961	24,142,961	**-**
72		SD-31	GC11	-	489,355	-	-	-	-	-	-	489,355	489,355	**-**
73		SD-31	GC12	-	2,081,063	-	-	-	-	-	-	2,081,063	2,081,063	**-**
74		SD-31	GC16	-	-	19,981,136	-	-	-	-	-	19,981,136	-	**19,981,136**
75		SD-31	GC17N	-	-	15,065,833	-	-	-	-	-	15,065,833	-	**15,065,833**
76		SD-31	GC17P	-	-	-	-	-	-	-	-	-	-	**-**
77		SD-31	GC19	-	-	3,970,752	-	-	-	-	-	3,970,752	-	**3,970,752**
78		SD-31	GC20	-	-	241,420	-	-	-	-	-	241,420	-	**241,420**
79		SD-31	GC22	-	-	-	785,600	-	-	-	-	785,600	-	**785,600**
80		SD-31	GC24	-	-	-	28,342,764	-	-	-	-	28,342,764	-	**28,342,764**
81		SD-31	GC25	-	-	-	46,892,538	-	-	-	-	46,892,538	-	**46,892,538**
82		SD-31	GC28	-	-	-	14,285,382	-	-	-	-	14,285,382	-	**14,285,382**
83		SD-31	GC32	-	-	-	-	125,336	-	-	-	125,336	-	**125,336**
84		SD-31	GC34	-	-	-	-	9,226,089	-	-	-	9,226,089	-	**9,226,089**
85		SD-31	GC37	-	-	-	-	-	1,224,395	-	-	1,224,395	-	**1,224,395**
86		SD-31	GC40	-	-	-	-	-	-	-	-	-	-	**-**
87		SD-31	GC41	-	-	-	-	-	7,235,662	-	-	7,235,662	-	**7,235,662**
88		SD-31	GC43	-	-	-	-	2,794,727	-	-	-	2,794,727	-	**2,794,727**
89		SD-31	GC44	-	-	-	-	-	-	-	-	-	-	**-**
90		SD-31	GC47	-	-	-	-	-	-	-	-	-	-	**-**
91		SD-31	GC48	-	-	-	-	-	-	-	1,640,070	1,640,070	-	**1,640,070**
92		SD-31	GC49	-	-	-	-	-	-	-	246,572	246,572	-	**246,572**
93	Subtotal			256,912	26,713,378	39,259,142	90,306,285	12,146,152	8,460,057	-	1,886,642	179,028,569	26,970,291	**152,058,278**
94	**Primary Voltage (< 3 MW)**													
95		SD-31	GC13	-	1,619,429	-	-	-	-	-	-	1,619,429	1,619,429	**-**
96		SD-31	GC19	-	-	-	-	-	-	-	-	-	-	**-**
97		SD-31	GC25	-	-	-	-	-	-	-	-	-	-	**-**
98		SD-31	GC26N	-	-	-	-	-	-	-	-	-	-	**-**
99		SD-31	GC26P	-	-	-	-	-	-	-	-	-	-	**-**
100		SD-31	GC30	-	-	8,933,972	-	-	-	-	-	8,933,972	-	**8,933,972**
101		SD-31	GC41	-	-	-	-	-	-	-	-	-	-	**-**
102		SD-31	GC44	-	-	-	-	-	-	-	-	-	-	**-**
103		SD-31	GC47	-	-	-	-	-	-	-	-	-	-	**-**
104		SD-31	GC48	-	-	-	-	-	-	-	-	-	-	**-**
105	Subtotal			-	1,619,429	8,933,972	-	-	-	-	-	10,553,401	1,619,429	**8,933,972**
106	**Customer-Owned, Metered (Sports Lighting)**													
107		SD-31	GC10	-	-	-	-	-	-	-	-	-	-	**-**
108		SD-31	GC15A	-	-	20,529	-	-	-	-	-	20,529	-	**20,529**

Work Paper 44.2 - Production Cost Run

Purpose: Identify the Green Choice kWh and Revenue in the Test Year

Line No.		Source Reference	Rate Code	Batch 1	Batch 2	Batch 3	Batch 4	Batch 5	Batch 6 5-Year	Batch 6 10-Year	Batch 6 Batch 6.3	Total	Expired Batch 1 & 2	Test Year Net of Batch 1 & 2
A		B	C	D	E	F	G	H	I	J	K	L	M	N
109		SD-31	GC27	-	-	-	7,663	-	-	-	-	7,663	-	**7,663**
110	Subtotal			-	-	20,529	7,663	-	-	-	-	28,192	-	**28,192**
111														
112	**Total kWh**			**18,925,727**	**79,364,472**	**67,643,505**	**131,833,359**	**39,584,000**	**11,007,251**	**107,151**	**2,505,253**	**350,970,718**	**98,290,199**	**252,680,519**
113														
114														
115	**Green Choice kWh (Test Year)**													
116	Remove Expired Batch 1 and Batch 2			(18,925,727)	(79,364,472)	-	-	-	-	-	-	(98,290,199)		
117				**-**	**-**	**67,643,505**	**131,833,359**	**39,584,000**	**11,007,251**	**107,151**	**2,505,253**	**252,680,519**		
118				*Batch 1 & 2 customers are assumed to have transitioned to the typical Fuel Adjustment Clause after contract expiration*										
119														
120	**Green Choice Rates ($/kWh)**													
121														
122	**Actual Tariff Prices (Rates)**	SD-31		**$ -**	**$ -**	**$ 0.03300**	**$ 0.03500**	**$ 0.05500**	**$ 0.08000**	**$ 0.09500**	**$ 0.05700**			
123														
124														
125	**Test Year Green Choice Revenue**													
126	Residential			$ -	$ -	$ 338,892	$ 728,461	$ 1,265,028	$ 35,187	$ 8,879	$ 8,317	$ 2,384,764		
127	Secondary Voltage (< 10 kW)			-	-	73,807	173,229	77,236	43,432	974	7,190	375,868		
128	Secondary Voltage (≥ 10 < 50 kW)			-	-	228,486	551,489	166,817	125,156	326	19,754	1,092,030		
129	Secondary Voltage (≥ 50 kW)			-	-	1,295,552	3,160,720	668,038	676,805	-	107,539	5,908,653		
130	Primary Voltage (< 3 MW)			-	-	294,821	-	-	-	-	-	294,821		
131	Customer-Owned, Metered (Sports Lighting)			-	-	677	268	-	-	-	-	946		
132				**$ -**	**$ -**	**$ 2,232,236**	**$ 4,614,168**	**$ 2,177,120**	**$ 880,580**	**$ 10,179**	**$ 142,799**	**$ 10,057,082**		

Work Paper 45 - Indirect

Purpose: Identify Indirect Costs in FY 2009 by FERC to Add these Costs Back to the Direct FERC and Remove from A&G (FERC 920)

Line No.		FERC Account	FY 2009 Source Reference	FY 2009 Actual	Reclassify Source Reference	Reclassify SHEC OH	Adjusted FY 2009 Actual	Test Year	Adjustment
A		B	C	D	E	F	G	H	I
1	**Indirect**								
2	STEAM GEN SUPV & ADMIN - AE	500	SD-55	$ (131,465)		$ -	$ (131,465)	$ -	$ 131,465
3	STEAM GEN SUPV & ADMIN - HPP	500	SD-55	(41,329)		-	(41,329)	-	41,329
4	STEAM GEN MISC EXP - HPP	506	SD-55	(3,007)		-	(3,007)	-	3,007
5	STEAM GEN MISC EXP - DCPP	506	SD-55	(499)		-	(499)	-	499
6	STEAM GEN MISC EXP - SHEC	506	SD-55	(233)	SD-73	233	-	-	-
7	STEAM MAINT SUPV & ADMIN - AE	510	SD-55	(3,960)		-	(3,960)	-	3,960
8	STEAM MAINT ELECTRIC - SHEC	513	SD-55	(29,783)	SD-73	29,783	-	-	-
9	STEAM MAINT ELECTRIC - DCPP	513	SD-55	(4,041)		-	(4,041)	-	4,041
10	STEAM MAINT MISC - DCPP	514	SD-55	(1,726)		-	(1,726)	-	1,726
11	GT SUPV & ADMIN - SHEC	546	SD-55	(4,059)		-	(4,059)	-	4,059
12	GT MAINT SUPV & ADMIN - AE	551	SD-55	(168)		-	(168)	-	168
13	GT MAINT GEN & ELECT - DCPP	553	SD-55	(61,638)		-	(61,638)	-	61,638
14	GT MAINT MISC PLANT - AE	554	SD-55	(44,978)		-	(44,978)	-	44,978
15	GT MAINT MISC PLANT - DCPP	554	SD-55	(1,094)		-	(1,094)	-	1,094
16	TRANS OPS SUPV & ADMIN-AE	560	SD-55	(1,241,230)		-	(1,241,230)	-	1,241,230
17	TRANS LOAD DISPATCHING	561	SD-55	(104)		-	(104)	-	104
18	TRANS SUBSTATION EXP - AE	562	SD-55	(196,229)		-	(196,229)	-	196,229
19	TRANS OH LINE EXP - AE	563	SD-55	(795,525)		-	(795,525)	-	795,525
20	TRANS UG LINE EXP	564	SD-55	(189)		-	(189)	-	189
21	TRANS MISC EXP - AE	566	SD-55	(3,221)		-	(3,221)	-	3,221
22	TRANS MAINT SUPV & ADMIN - AE	568	SD-55	(728)		-	(728)	-	728
23	TRANS MAINT STRUCTURES - AE	569	SD-55	(8,037)		-	(8,037)	-	8,037
24	TRANS SUBSTATION MAINT - AE	570	SD-55	(1,193,453)		-	(1,193,453)	-	1,193,453
25	DIST OPS SUPV & ADMIN	580	SD-55	(380,979)		-	(380,979)	-	380,979
26	DIST LOAD DISPATCHING	581	SD-55	(36,274)		-	(36,274)	-	36,274
27	DIST SUBSTATION EXP	582	SD-55	(18,616)		-	(18,616)	-	18,616
28	DIST OH LINE EXP	583	SD-55	(4,736,458)		-	(4,736,458)	-	4,736,458
29	DIST UG LINE EXP	584	SD-55	(3,527,972)		-	(3,527,972)	-	3,527,972
30	DIST STREETLIGHTING EXP	585	SD-55	(341,312)		-	(341,312)	-	341,312
31	METER EXP	586	SD-55	(346,718)		-	(346,718)	-	346,718
32	DIST MAPS AND RECORDS (GIS)	588	SD-55	(582,279)		-	(582,279)	-	582,279
33	DIST MISC EXP	588	SD-55	(238,361)		-	(238,361)	-	238,361
34	DIST LEASE & OFFICE RENTAL	589	SD-55	(507)		-	(507)	-	507
35	DIST SUBSTATION MAINT	592	SD-55	(199,763)		-	(199,763)	-	199,763
36	DIST OH TREE TRIMMING	593	SD-55	(101,879)		-	(101,879)	-	101,879
37	DIST OH SERVICES MAINT	593	SD-55	(11,260)		-	(11,260)	-	11,260
38	DIST OH POLE & FIXTURE MAINT	593	SD-55	(2,454)		-	(2,454)	-	2,454
39	DIST OH LINE & DEVICES MAINT	593	SD-55	(365)		-	(365)	-	365
40	DIST OH LINE & DEVICES MAINT	594	SD-55	(41,921)		-	(41,921)	-	41,921
41	DIST LINE TRANSFORMER MAINT	595	SD-55	(611)		-	(611)	-	611
42	DIST STREETLIGHTING MAINT	596	SD-55	(724)		-	(724)	-	724
43	DIST COST OF CONTRACT WORK	598	SD-55	(24,410)		-	(24,410)	-	24,410

Work Paper 45 - Indirect

Purpose: Identify Indirect Costs in FY 2009 by FERC to Add these Costs Back to the Direct FERC and Remove from A&G (FERC 920)

Line No.		FERC Account	FY 2009 Source Reference	FY 2009 Actual	Reclassify Source Reference	Reclassify SHEC OH	Adjusted FY 2009 Actual	Test Year	Adjustment
A		B	C	D	E	F	G	H	I
44	DIST REIMBURSEMENT OF WORK	598	SD-55	(5,388)		-	(5,388)	-	5,388
45	DIST NIGHTWATCHMAN MAINT	598	SD-55	(264)		-	(264)	-	264
46	DIST MISC MAINT	598	SD-55	(73)		-	(73)	-	73
47	CONSV & RENEWABLE SUPV & ADMIN	907	SD-55	(1,536)		-	(1,536)	-	1,536
48	RESIDENTIAL PRGMS & INCENTIVES	908	SD-55	(337)		-	(337)	-	337
49	ADMIN SALARIES - SUPP	920	SD-55	(17,423)		-	(17,423)	-	17,423
50	ADMIN SALARIES - TRAN	920	SD-55	(2,255)		-	(2,255)	-	2,255
51	COMMUNICATION EXP - AE	930	SD-55	(35,786)		-	(35,786)	-	35,786
52	MAINT OFFICE BLDG & EQUIP - AE	935	SD-55	(100)		-	(100)	-	100
53	STEAM GEN MISC EXP - SHEC	549		-	SD-73	(233)	(233)	-	233
54	STEAM MAINT ELECTRIC - SHEC	553		-	SD-73	(29,783)	(29,783)	-	29,783
55	EXP NONUTILITY OPS-CHILLER	417	SD-55	(125,676)		-	(125,676)	-	125,676
56	Move to General and Administrative	920		-		-	-	(14,548,394)	(14,548,394)
57				$ (14,548,394)		$ -	$ (14,548,394)	$ (14,548,394)	$ -

Appendix E: Proposed Austin Energy Electric Rate Schedule

Proposed Austin Energy Electric Rate Schedule

August 29, 2011

PROPOSED CITY OF AUSTIN ELECTRIC RATE SCHEDULE

TABLE OF CONTENTS

PROPOSED CITY OF AUSTIN ELECTRIC RATE SCHEDULE

RESIDENTIAL

Application

This rate is applicable to electric service required by residential customers in single-family dwellings, mobile homes, town houses, or individually metered apartment units. When a portion of a residence or household unit is used for non-residential purposes only as defined by Section 13-2-260 of the Austin City Code, this rate may be applied. This rate is not applicable to separately metered service to swimming pools, boat docks, electric gates, individual hotel and motel rooms and other non-residential uses.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin, which may be amended from time to time. Electric service of one standard character will be delivered to one point of service on the customer's premise and measured through one meter.

Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$15.00 Per Month	$15.00 Per Month
Electric Delivery	$10.00 Per Month	$10.00 Per Month
Energy Charge		
0- 500 kWh	4.411 ¢ Per kWh	5.514 ¢ Per kWh
501-1,000 kWh	7.611 ¢ Per kWh	9.514 ¢ Per kWh
1,001-1,500 kWh	9.611 ¢ Per kWh	12.014 ¢ Per kWh
1,501-2,500 kWh	10.811 ¢ Per kWh	13.514 ¢ Per kWh
2,501 kWh and greater	11.611 ¢ Per kWh	14.514 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.114 ¢ Per kWh	0.114 ¢ Per kWh
Energy Efficiency	0.301 ¢ Per kWh	0.301 ¢ Per kWh
Regulatory Charge	0.729 ¢ Per kWh	0.729 ¢ Per kWh

Time-Of-Use Option

In lieu of the charges above, customers may choose the following time-of-use charges to be applied for a term of not less than 12 consecutive billing months. Customers selecting this time-of-use option shall permit Austin Energy to install all equipment necessary for time-of-use metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. This option will be limited to the first 2,000 eligible customers who request service. A waiting list will be maintained and will be filled as customers choose to opt out of time-of-use service.

Time-Of-Use Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$18.00 Per Month	$18.00 Per Month
Electric Delivery	$10.00 Per Month	$10.00 Per Month
Energy Charge		
Off-Peak		
0- 500 kWh	2.200 ¢ Per kWh	3.800 ¢ Per kWh
501-1,000 kWh	2.700 ¢ Per kWh	4.500 ¢ Per kWh
1,001-1,500 kWh	3.290 ¢ Per kWh	5.500 ¢ Per kWh
1,501-2,500 kWh	4.000 ¢ Per kWh	6.000 ¢ Per kWh
2,501 kWh and greater	7.500 ¢ Per kWh	9.500 ¢ Per kWh
Mid-Peak		
0- 500 kWh	3.200 ¢ Per kWh	7.500 ¢ Per kWh
501-1,000 kWh	4.892 ¢ Per kWh	8.685 ¢ Per kWh
1,001-1,500 kWh	7.100 ¢ Per kWh	9.500 ¢ Per kWh
1,501-2,500 kWh	8.536 ¢ Per kWh	10.000 ¢ Per kWh
2,501 kWh and greater	12.000 ¢ Per kWh	12.000 ¢ Per kWh
On-Peak		
0- 500 kWh	0.000 ¢ Per kWh	10.500 ¢ Per kWh
501-1,000 kWh	0.000 ¢ Per kWh	11.750 ¢ Per kWh
1,001-1,500 kWh	0.000 ¢ Per kWh	12.764 ¢ Per kWh
1,501-2,500 kWh	0.000 ¢ Per kWh	13.500 ¢ Per kWh
2,501 kWh and greater	0.000 ¢ Per kWh	17.500 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		

Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.114 ¢ Per kWh	0.114 ¢ Per kWh
Energy Efficiency	0.301 ¢ Per kWh	0.301 ¢ Per kWh
Regulatory Charge	0.729 ¢ Per kWh	0.729 ¢ Per kWh

Time-Of-Use Periods

	Billing Months **October through May**
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 10:00 P.M. every day
On-Peak hours	None

	Billing Months **June through September**
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 2:00 P.M. and 8:00 P.M. – 10:00 P.M. Monday – Friday 6:00 A.M. – 10:00 P.M. Saturday – Sunday
On-Peak hours	2:00 P.M. – 8:00 P.M. Monday – Friday

GreenChoice® Option

Customers who qualify for service on this rate may choose to participate in Austin Energy's GreenChoice® renewable energy program as described in the *GreenChoice® Energy Rider*.

PROPOSED CITY OF AUSTIN ELECTRIC RATE SCHEDULE

SECONDARY VOLTAGE LESS THAN 10 kW

Application

This rate is applicable to electric service required by any customer served at a secondary voltage (less than 12,500 volts - nominal) to whom no other specific rate applies, and whose demand for power does not meet or exceed 10 kW during the most recent June through September billing months or as determined by Austin Energy. This rate shall be applied for a term of not less than 12 months following the month in which the criteria are met.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin, which may be amended from time to time. Electric service of one standard character will be delivered to one point of service on the customer's premise and measured through one meter.

Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$18.00 Per Month	$18.00 Per Month
Electric Delivery	$2.50 Per Billed kW	$2.50 Per Billed kW
Demand Charge	$3.00 Per Billed kW	$3.00 Per Billed kW
Energy Charge	6.443 ¢ Per kWh	8.054 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.113 ¢ Per kWh	0.113 ¢ Per kWh
Energy Efficiency	0.296 ¢ Per kWh	0.296 ¢ Per kWh
Regulatory Charge	$2.33 Per Billed kW	$2.33 Per Billed kW

Time-Of-Use Option

In lieu of the charges above, customers may choose the following time-of-use charges to be applied for a term of not less than 12 consecutive billing months. Customers selecting this time-of-use option shall permit Austin Energy to install all equipment necessary for time-of-use metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. This option shall be limited to the greater of: 1) 10 percent of the customers in this rate class or, 2) the first 10 customers who request enrollment. A waiting list will be maintained and will be filled as customers select to opt out of time-of-use-service.

PROPOSED CITY OF AUSTIN ELECTRIC RATE SCHEDULE

Time-Of-Use Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	21.60 Per Month	21.60 Per Month
Electric Delivery	$2.50 Per Billed kW	$2.50 Per Billed kW
Demand Charge		
On-Peak	$0.00 Per Billed kW	$4.07 Per Billed kW
Mid-Peak	$0.00 Per Billed kW	$0.00 Per Billed kW
Energy Charge		
Off-Peak	3.943 ¢ Per kWh	3.943 ¢ Per kWh
Mid-Peak	8.520 ¢ Per kWh	8.520 ¢ Per kWh
On-Peak	0.000 ¢ Per kWh	11.84 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.113 ¢ Per kWh	0.113 ¢ Per kWh
Energy Efficiency	0.296 ¢ Per kWh	0.296 ¢ Per kWh
Regulatory Charge	$2.33 Per Billed kW	$2.33 Per Billed kW

Time-Of-Use Periods

	Billing Months October through May
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 10:00 P.M. every day
On-Peak hours	None

	Billing Months June through September
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 2:00 P.M. and 8:00 P.M. – 10:00 P.M. Monday – Friday 6:00 A.M. – 10:00 P.M. Saturday – Sunday
On-Peak hours	2:00 P.M. – 8:00 P.M. Monday – Friday

GreenChoice® Option

Customers who qualify for service on this rate may choose to participate in Austin Energy's GreenChoice renewable energy program as described in the *GreenChoice® Energy Rider*.

Terms and Conditions

Billing Demand: Billing Demand shall be the kilowatt demand during the 15-minute interval of greatest use during the current billing month as indicated or recorded by metering equipment installed by Austin Energy.

SECONDARY VOLTAGE LESS THAN 10 kW (A)

Application

This rate is applicable to electric service required by any customer served at a secondary voltage (less than 12,500 volts - nominal) to whom no other specific rate applies, whose demand for power does not meet or exceed 10 kW during the most recent June through September billing months, and who on the day prior to the initial effective date of this tariff was an Austin Energy customer served under a rate that did not assess any charges based on billing demand (kW) or as determined by Austin Energy. This rate shall be applied for a term of not less than 12 months following the month in which the criteria are met.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin, which may be amended from time to time. Electric service of one standard character will be delivered to one point of service on the customer's premise and measured through one meter.

Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$18.00 Per Month	$18.00 Per Month
Electric Delivery	$1.50 Per Billed kW	$1.50 Per Billed kW
Demand Charge	$1.00 Per Billed kW	$1.00 Per Billed kW
Energy Charge	7.278 ¢ Per kWh	9.097 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.113 ¢ Per kWh	0.113 ¢ Per kWh
Energy Efficiency	0.296 ¢ Per kWh	0.296 ¢ Per kWh
Regulatory Charge	0.711 ¢ Per kWh	0.711 ¢ Per kWh

Time-Of-Use Option

In lieu of the charges above, customers may choose the following time-of-use charges to be applied for a term of not less than 12 consecutive billing months. Customers selecting this time-of-use option shall permit Austin Energy to install all equipment necessary for time-of-use metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. This option shall be limited to the greater of: 1) 10 percent of the

customers in this rate class or, 2) the first 10 customers who request enrollment. A waiting list will be maintained and will be filled as customers select to opt out of time-of-use-service.

Time-Of-Use Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	21.60 Per Month	21.60 Per Month
Electric Delivery	$2.50 Per Billed kW	$2.50 Per Billed kW
Demand Charge		
On-Peak	$0.00 Per Billed kW	$4.07 Per Billed kW
Mid-Peak	$0.00 Per Billed kW	$0.00 Per Billed kW
Energy Charge		
Off-Peak	3.943 ¢ Per kWh	3.943 ¢ Per kWh
Mid-Peak	8.520 ¢ Per kWh	8.520 ¢ Per kWh
On-Peak	0.000 ¢ Per kWh	11.84 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.113 ¢ Per kWh	0.113 ¢ Per kWh
Energy Efficiency	0.296 ¢ Per kWh	0.296 ¢ Per kWh
Regulatory Charge	$2.33 Per Billed kW	$2.33 Per Billed kW

Time-Of-Use Periods

	Billing Months October through May
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 10:00 P.M. every day
On-Peak hours	None

	Billing Months June through September
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 2:00 P.M. and 8:00 P.M. – 10:00 P.M. Monday – Friday

	6:00 A.M. – 10:00 P.M. Saturday – Sunday
On-Peak hours	2:00 P.M. – 8:00 P.M. Monday – Friday

GreenChoice® Option

Customers who qualify for service on this rate may choose to participate in Austin Energy's GreenChoice renewable energy program as described in the *GreenChoice® Energy Rider*.

Terms and Conditions

Billing Demand: Billing Demand shall be the kilowatt demand during the 15-minute interval of greatest use during the current billing month as indicated or recorded by metering equipment installed by Austin Energy.

SECONDARY VOLTAGE GREATER THAN OR EQUAL TO 10 kW AND LESS THAN 50 kW

Application

This rate is applicable to electric service required by any customer served at a secondary voltage (less than 12,500 volts - nominal) to whom no other specific rate applies, and whose demand for power meets or exceeds 10 kW and does not meet or exceed 50 kW during the most recent June through September billing months or as determined by Austin Energy. This rate shall be applied for a term of not less than 12 months following the month in which the criteria are met.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin, which may be amended from time to time. Electric service of one standard character will be delivered to one point of service on the customer's premise and measured through one meter.

Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$25.00 Per Month	$25.00 Per Month
Electric Delivery	$4.00 Per Billed kW	$4.00 Per Billed kW
Demand Charge	$5.50 Per Billed kW	$6.50 Per Billed kW
Energy Charge	5.491 ¢ Per kWh	5.868 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.088 ¢ Per kWh	0.088 ¢ Per kWh
Energy Efficiency	0.0231 ¢ Per kWh	0.0231 ¢ Per kWh
Regulatory Charge	$2.44 Per Billed kW	$2.44 Per Billed kW

Time-Of-Use Option

In lieu of the charges above, customers may choose the following time-of-use charges to be applied for a term of not less than 12 consecutive billing months. Customers selecting this time-of-use option shall permit Austin Energy to install all equipment necessary for time-of-use metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. This option shall be limited to the greater of: 1) 10 percent of the

customers in this rate class or, 2) the first 10 customers who request enrollment. A waiting list will be maintained and will be filled as customers select to opt out of time-of-use-service.

Time-Of-Use Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$30.00 Per Month	$30.00 Per Month
Electric Delivery	$4.00 Per Billed kW	$4.00 Per Billed kW
Demand Charge		
On-Peak	$0.00 Per Billed kW	$6.72 Per Billed kW
Mid-Peak	$0.00 Per Billed kW	$0.00 Per Billed kW
Energy Charge		
Off-Peak	3.539 ¢ Per kWh	3.539 ¢ Per kWh
Mid-Peak	7.646 ¢ Per kWh	7.646 ¢ Per kWh
On-Peak	0.000 ¢ Per kWh	10.625 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.088 ¢ Per kWh	0.088 ¢ Per kWh
Energy Efficiency	0.231 ¢ Per kWh	0.231 ¢ Per kWh
Regulatory Charge	$2.44 Per Billed kW	$2.44 Per Billed kW

Time-Of-Use Periods

	Billing Months October through May
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 10:00 P.M. every day
On-Peak hours	None

	Billing Months June through September
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 2:00 P.M. and 8:00 P.M. – 10:00 P.M. Monday – Friday

	6:00 A.M. – 10:00 P.M. Saturday – Sunday
On-Peak hours	2:00 P.M. – 8:00 P.M. Monday – Friday

GreenChoice® Option

Customers who qualify for service on this rate may choose to participate in Austin Energy's GreenChoice renewable energy program as described in the *GreenChoice® Energy Rider*.

Terms and Conditions

Billing Demand and Power Factor Adjustment: Billing Demand before power factor correction shall be the kilowatt demand during the 15-minute interval of greatest use during the current billing month as indicated or recorded by metering equipment installed by Austin Energy. When power factor during the interval of greatest use is less than 90 percent as indicated or recorded by metering equipment installed by Austin Energy, Billing Demand shall be determined by multiplying kilowatt demand during the 15-minute interval of greatest use by 90 percent and dividing by the indicated or recorded power factor during the interval of greatest use.

SECONDARY VOLTAGE GREATER THAN OR EQUAL TO 10 kW AND LESS THAN 50 kW (A)

Application

This rate is applicable to electric service required by any customer served at a secondary voltage (less than 12,500 volts - nominal) to whom no other specific rate applies, and whose demand for power meets or exceeds 10 kW and does not meet or exceed 50 kW during the most recent June through September billing months and who on the day prior to the initial effective date of this tariff was an Austin Energy customer served under a rate that did not assess any charges based on billing demand (kW) or as determined by Austin Energy. This rate shall be applied for a term of not less than 12 months following the month in which the criteria are met.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin, which may be amended from time to time. Electric service of one standard character will be delivered to one point of service on the customer's premise and measured through one meter.

Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$25.00 Per Month	$25.00 Per Month
Electric Delivery	$2.00 Per Billed kW	$2.00 Per Billed kW
Demand Charge	$2.00 Per Billed kW	$2.00 Per Billed kW
Energy Charge	7.023 ¢ Per kWh	7.505 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.088 ¢ Per kWh	0.088 ¢ Per kWh
Energy Efficiency	0.231 ¢ Per kWh	0.231 ¢ Per kWh
Regulatory Charge	$2.44 Per Billed kW	$2.44 Per Billed kW

Time-Of-Use Option

In lieu of the charges above, customers may choose the following time-of-use charges to be applied for a term of not less than 12 consecutive billing months. Customers selecting this time-of-use option shall permit Austin Energy to install all equipment necessary for time-of-use metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. This option shall be limited to the greater of: 1) 10 percent of the customers in this rate class or, 2) the first 10 customers who request enrollment. A waiting list will be maintained and will be filled as customers select to opt out of time-of-use-service.

Time-Of-Use Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$30.00 Per Month	$30.00 Per Month
Electric Delivery	$4.00 Per Billed kW	$4.00 Per Billed kW
Demand Charge		
On-Peak	$0.00 Per Billed kW	$6.72 Per Billed kW
Mid-Peak	$0.00 Per Billed kW	$0.00 Per Billed kW
Energy Charge		
Off-Peak	3.539 ¢ Per kWh	3.539 ¢ Per kWh
Mid-Peak	7.646 ¢ Per kWh	7.646 ¢ Per kWh
On-Peak	0.000 ¢ Per kWh	10.625 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.088 ¢ Per kWh	0.088 ¢ Per kWh
Energy Efficiency	0.231 ¢ Per kWh	0.231 ¢ Per kWh
Regulatory Charge	$2.44 Per Billed kW	$2.44 Per Billed kW

Time-Of-Use Periods

	Billing Months October through May
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 10:00 P.M. every day
On-Peak hours	None

	Billing Months June through September
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 2:00 P.M. and 8:00 P.M. – 10:00 P.M. Monday – Friday 6:00 A.M. – 10:00 P.M. Saturday – Sunday
On-Peak hours	2:00 P.M. – 8:00 P.M. Monday – Friday

GreenChoice® Option

Customers who qualify for service on this rate may choose to participate in Austin Energy's GreenChoice renewable energy program as described in the *GreenChoice® Energy Rider*.

Terms and Conditions

Billing Demand: Billing Demand shall be the kilowatt demand during the 15-minute interval of greatest use during the current billing month as indicated or recorded by metering equipment installed by Austin Energy.

SECONDARY VOLTAGE GREATER THAN OR EQUAL TO 50 kW

Application

This rate is applicable to electric service required by any customer served at a secondary voltage (less than 12,500 volts - nominal) to whom no other specific rate applies, and whose demand for power meets or exceeds 50 kW during the most recent June through September billing months or as determined by Austin Energy. This rate shall be applied for a term of not less than 12 months following the month in which the criteria are met.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin, which may be amended from time to time. Electric service of one standard character will be delivered to one point of service on the customer's premise and measured through one meter.

Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$65.00 Per Month	$65.00 Per Month
Electric Delivery	$4.50 Per Billed kW	$4.50 Per Billed kW
Demand Charge	$7.00 Per Billed kW	$8.00 Per Billed kW
Energy Charge	4.812 ¢ Per kWh	5.142 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.078 ¢ Per kWh	0.078 ¢ Per kWh
Energy Efficiency	0.206 ¢ Per kWh	0.206 ¢ Per kWh
Regulatory Charge	$2.57 Per Billed kW	$2.57 Per Billed kW

Time-Of-Use Option

In lieu of the charges above, customers may choose the following time-of-use charges to be applied for a term of not less than 12 consecutive billing months. Customers selecting this time-of-use option shall permit Austin Energy to install all equipment necessary for time-of-use metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. This option shall be limited to the greater of: 1) 10 percent of the customers in this rate class or, 2) the first 10 customers who request enrollment. A waiting list will be maintained and will be filled as customers select to opt out of time-of-use-service.

PROPOSED CITY OF AUSTIN ELECTRIC RATE SCHEDULE

Time-Of-Use Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$68.25 Per Month	$68.25 Per Month
Electric Delivery	$4.00 Per Billed kW	$4.00 Per Billed kW
Demand Charge		
On-Peak	$0.00 Per Billed kW	$8.39 Per Billed kW
Mid-Peak	$0.00 Per Billed kW	$0.00 Per Billed kW
Energy Charge		
Off-Peak	3.313 ¢ Per kWh	3.313 ¢ Per kWh
Mid-Peak	7.160 ¢ Per kWh	7.160 ¢ Per kWh
On-Peak	0.000 ¢ Per kWh	9.950 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.078 ¢ Per kWh	0.078 ¢ Per kWh
Energy Efficiency	0.206 ¢ Per kWh	0.206 ¢ Per kWh
Regulatory Charge	$2.57 Per Billed kW	$2.57 Per Billed kW

Time-Of-Use Periods

	Billing Months October through May
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 10:00 P.M. every day
On-Peak hours	None

	Billing Months June through September
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 2:00 P.M. and 8:00 P.M. – 10:00 P.M. Monday – Friday 6:00 A.M. – 10:00 P.M. Saturday – Sunday
On-Peak hours	2:00 P.M. – 8:00 P.M. Monday – Friday

GreenChoice® Option

Customers who qualify for service on this rate may choose to participate in Austin Energy's GreenChoice renewable energy program as described in the *GreenChoice® Energy Rider*.

Terms and Conditions

Billing Demand and Power Factor Adjustment: Billing Demand before power factor correction shall be the kilowatt demand during the 15-minute interval of greatest use during the current billing month as indicated or recorded by metering equipment installed by Austin Energy. When power factor during the interval of greatest use is less than 90 percent as indicated or recorded by metering equipment installed by Austin Energy, Billing Demand shall be determined by multiplying kilowatt demand during the 15-minute interval of greatest use by 90 percent and dividing by the indicated or recorded power factor during the interval of greatest use.

SECONDARY VOLTAGE GREATER THAN OR EQUAL TO 50 kW (A)

Application

This rate is applicable to electric service required by any customer served at a secondary voltage (less than 12,500 volts - nominal) to whom no other specific rate applies, and whose demand for power meets or exceeds 50 kW during the most recent June through September billing months and who on the day prior to the initial effective date of this tariff was an Austin Energy customer served under a rate that did not assess any charges based on billing demand (kW) or as determined by Austin Energy. This rate shall be applied for a term of not less than 12 months following the month in which the criteria are met.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin, which may be amended from time to time. Electric service of one standard character will be delivered to one point of service on the customer's premise and measured through one meter.

Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$65.00 Per Month	$65.00 Per Month
Electric Delivery	$2.00 Per Billed kW	$2.00 Per Billed kW
Demand Charge	$2.00 Per Billed kW	$2.00 Per Billed kW
Energy Charge	7.351 ¢ Per kWh	7.855 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.078 ¢ Per kWh	0.078 ¢ Per kWh
Energy Efficiency	0.206 ¢ Per kWh	0.206 ¢ Per kWh
Regulatory Charge	$2.57 Per Billed kW	$2.57 Per Billed kW

Time-Of-Use Option

In lieu of the charges above, customers may choose the following time-of-use charges to be applied for a term of not less than 12 consecutive billing months. Customers selecting this time-of-use option shall permit Austin Energy to install all equipment necessary for time-of-use metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. This option shall be limited to the greater of: 1) 10 percent of the

customers in this rate class or, 2) the first 10 customers who request enrollment. A waiting list will be maintained and will be filled as customers select to opt out of time-of-use-service.

Time-Of-Use Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$68.25 Per Month	$68.25 Per Month
Electric Delivery	$4.00 Per Billed kW	$4.00 Per Billed kW
Demand Charge		
On-Peak	$0.00 Per Billed kW	$8.39 Per Billed kW
Mid-Peak	$0.00 Per Billed kW	$0.00 Per Billed kW
Energy Charge		
Off-Peak	3.313 ¢ Per kWh	3.313 ¢ Per kWh
Mid-Peak	7.160 ¢ Per kWh	7.160 ¢ Per kWh
On-Peak	0.000 ¢ Per kWh	9.950 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.078 ¢ Per kWh	0.078 ¢ Per kWh
Energy Efficiency	0.206 ¢ Per kWh	0.206 ¢ Per kWh
Regulatory Charge	$2.57 Per Billed kW	$2.57 Per Billed kW

Time-Of-Use Periods

	Billing Months October through May
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 10:00 P.M. every day
On-Peak hours	None

	Billing Months June through September
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 2:00 P.M. and 8:00 P.M. – 10:00 P.M. Monday – Friday

	6:00 A.M. – 10:00 P.M. Saturday – Sunday
On-Peak hours	2:00 P.M. – 8:00 P.M. Monday – Friday

GreenChoice® Option

Customers who qualify for service on this rate may choose to participate in Austin Energy's GreenChoice renewable energy program as described in the *GreenChoice® Energy Rider*.

Terms and Conditions

Billing Demand: Billing Demand shall be the kilowatt demand during the 15-minute interval of greatest use during the current billing month as indicated or recorded by metering equipment installed by Austin Energy.

PRIMARY VOLTAGE LESS THAN 3 MW

Application

This rate is applicable to electric service required by any customer served at primary voltage (greater than 12,500 volts and less than 69,000 volts - nominal) to whom no other specific rate applies, and whose demand for power does not meet or exceed 3,000 kW during the most recent June through September billing months or as determined by Austin Energy. This rate shall be applied for a term of not less than 12 months following the month in which the criteria are met.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin, which may be amended from time to time. Electric service of one standard character will be delivered to one point of service on the customer's premise and measured through one meter.

Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$250.00 Per Month	$250.00 Per Month
Electric Delivery	$2.50 Per Billed kW	$2.50 Per Billed kW
Demand Charge	$9.00 Per Billed kW	$10.00 Per Billed kW
Energy Charge	3.862 ¢ Per kWh	4.127 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.066 ¢ Per kWh	0.066 ¢ Per kWh
Energy Efficiency	0.0174 ¢ Per kWh	0.0174 ¢ Per kWh
Regulatory Charge	$2.28 Per Billed kW	$2.28 Per Billed kW

Time-Of-Use Option

In lieu of the charges above, customers may choose the following time-of-use charges to be applied for a term of not less than 12 consecutive billing months. Customers selecting this time-of-use option shall permit Austin Energy to install all equipment necessary for time-of-use metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. This option shall be limited to the greater of: 1) 10 percent of the customers in this rate class or, 2) the first 10 customers who request enrollment. A waiting list will be maintained and will be filled as customers select to opt out of time-of-use-service.

PROPOSED CITY OF AUSTIN ELECTRIC RATE SCHEDULE

Time-Of-Use Charges

	Billing Months October Through May	Billing Months June Through September
Customer Charge	$262.50 Per Month	$262.50 Per Month
Electric Delivery	$2.50 Per Billed kW	$2.50 Per Billed kW
Demand Charge		
On-Peak	$0.00 Per Billed kW	$13.69 Per Billed kW
Mid-Peak	$12.29 Per Billed kW	$0.00 Per Billed kW
Energy Charge		
Off-Peak	1.715 ¢ Per kWh	1.715 ¢ Per kWh
Mid-Peak	3.706 ¢ Per kWh	3.706 ¢ Per kWh
On-Peak	0.000 ¢ Per kWh	5.150 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.066 ¢ Per kWh	0.066 ¢ Per kWh
Energy Efficiency	0.174 ¢ Per kWh	0.174 ¢ Per kWh
Regulatory Charge	$2.28 Per Billed kW	$2.28 Per Billed kW

Time-Of-Use Periods

	Billing Months October through May
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 10:00 P.M. every day
On-Peak hours	None

	Billing Months June through September
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 2:00 P.M. and 8:00 P.M. – 10:00 P.M. Monday – Friday 6:00 A.M. – 10:00 P.M. Saturday – Sunday
On-Peak hours	2:00 P.M. – 8:00 P.M. Monday – Friday

GreenChoice® Option

Customers who qualify for service on this rate may choose to participate in Austin Energy's GreenChoice renewable energy program as described in the *GreenChoice® Energy Rider*.

Terms and Conditions

Billing Demand and Power Factor Adjustment: Billing Demand before power factor correction shall be the kilowatt demand during the 15-minute interval of greatest use during the current billing month as indicated or recorded by metering equipment installed by Austin Energy. When power factor during the interval of greatest use is less than 90 percent as indicated or recorded by metering equipment installed by Austin Energy, Billing Demand shall be determined by multiplying kilowatt demand during the 15-minute interval of greatest use by 90 percent and dividing by the indicated or recorded power factor during the interval of greatest use.

PRIMARY VOLTAGE GREATER THAN OR EQUAL TO 3 MW AND LESS THAN 20 MW

Application

This rate is applicable to electric service required by any customer served at primary voltage (greater than 12,500 volts and less than 69,000 volts - nominal) to whom no other specific rate applies, and whose demand for power meets or exceeds 3,000 kW and does not meet or exceed 20,000 kW during the most recent June through September billing months or as determined by Austin Energy. This rate shall be applied for a term of not less than 12 months following the month in which the criteria are met.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin which may be amended from time to time. Electric service of one standard character will be delivered to one point of service on the customer's premise and measured through one meter.

Charges

	Billing Months October through May	**Billing Months June through September**
Customer Charge	$2,000.00 Per Month	$2,000.00 Per Month
Electric Delivery	$3.50 Per Billed kW	$3.50 Per Billed kW
Demand Charge	$12.00 Per Billed kW	$13.00 Per Billed kW
Energy Charge	3.747 ¢ Per kWh	4.004 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.062 ¢ Per kWh	0.062 ¢ Per kWh
Energy Efficiency	0.162 ¢ Per kWh	0.162 ¢ Per kWh
Regulatory Charge	$2.93 Per Billed kW	$2.93 Per Billed kW

Time-Of-Use Option

In lieu of the charges above, customers may choose the following time-of-use charges to be applied for a term of not less than 12 consecutive billing months. Customers selecting this time-of-use option shall permit Austin Energy to install all equipment necessary for time-of-use metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. This option shall be limited to the greater of: 1) 10 percent of the

customers in this rate class or, 2) the first 10 customers who request enrollment. A waiting list will be maintained and will be filled as customers select to opt out of time-of-use-service.

Time-Of-Use Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$2,000.00 Per Month	$2,000.00 Per Month
Electric Delivery	$3.50 Per Billed kW	$3.50 Per Billed kW
Demand Charge		
On-Peak	$0.00 Per Billed kW	$13.77 Per Billed kW
Mid-Peak	$12.37 Per Billed kW	$0.00 Per Billed kW
Energy Charge		
Off-Peak	1.715 ¢ Per kWh	1.715 ¢ Per kWh
Mid-Peak	3.706 ¢ Per kWh	3.706 ¢ Per kWh
On-Peak	0.000 ¢ Per kWh	5.150 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.062 ¢ Per kWh	0.062 ¢ Per kWh
Energy Efficiency	0.162 ¢ Per kWh	0.162 ¢ Per kWh
Regulatory Charge	$2.93 Per Billed kW	$2.93 Per Billed kW

Time-Of-Use Periods

	Billing Months October through May
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 10:00 P.M. every day
On-Peak hours	None

	Billing Months June through September
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 2:00 P.M. and 8:00 P.M. – 10:00 P.M. Monday – Friday

	6:00 A.M. – 10:00 P.M. Saturday – Sunday
On-Peak hours	2:00 P.M. – 8:00 P.M. Monday – Friday

GreenChoice® Option

Customers who qualify for service on this rate may choose to participate in Austin Energy's GreenChoice renewable energy program as described in the *GreenChoice® Energy Rider*.

Terms And Conditions

Billing Demand and Power Factor Adjustment: Billing Demand before power factor correction shall be the kilowatt demand during the 15-minute interval of greatest use during the current billing month as indicated or recorded by metering equipment installed by Austin Energy. When power factor during the interval of greatest use is less than 90 percent as indicated or recorded by metering equipment installed by Austin Energy, Billing Demand shall be determined by multiplying kilowatt demand during the 15-minute interval of greatest use by 90 percent and dividing by the indicated or recorded power factor during the interval of greatest use.

PROPOSED CITY OF AUSTIN ELECTRIC RATE SCHEDULE

PRIMARY VOLTAGE GREATER THAN OR EQUAL TO 20 MW

Application

This rate is applicable to electric service required by any customer served at primary voltage (greater than 12,500 volts and less than 69,000 volts - nominal) to whom no other specific rate applies, and whose demand for power meets or exceeds 20,000 kW during the most recent June through September billing months or as determined by Austin Energy. This rate shall be applied for a term of not less than 12 months following the month in which the criteria are met.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin, which may be amended from time to time. Electric service of one standard character will be delivered to one point of service on the customer's premise and measured through one meter.

Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$2,500.00 Per Month	$2,500.00 Per Month
Electric Delivery	$3.50 Per Billed kW	$3.50 Per Billed kW
Demand Charge	$12.00 Per Billed kW	$13.00 Per Billed kW
Energy Charge	3.692 ¢ Per kWh	3.945 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.059 ¢ Per kWh	0.059 ¢ Per kWh
Energy Efficiency	0.156 ¢ Per kWh	0.156 ¢ Per kWh
Regulatory Charge	$2.92 Per Billed kW	$2.92 Per Billed kW

Time-Of-Use Option

In lieu of the charges above, customers may choose the following time-of-use charges to be applied for a term of not less than 12 consecutive billing months. Customers selecting this time-of-use option shall permit Austin Energy to install all equipment necessary for time-of-use metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. This option shall be limited to the greater of: 1) 10 percent of the customers in this rate class or, 2) the first 10 customers who request enrollment. A waiting list will be maintained and will be filled as customers select to opt out of time-of-use-service.

PROPOSED CITY OF AUSTIN ELECTRIC RATE SCHEDULE

Time-Of-Use Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$2,500.00 Per Month	$2,500.00 Per Month
Electric Delivery	$3.50 Per Billed kW	$3.50 Per Billed kW
Demand		
On-Peak	$0.00 Per Billed kW	$13.70 Per Billed kW
Mid-Peak	$12.30 Per Billed kW	$0.00 Per Billed kW
Energy		
Off-Peak	1.715 ¢ Per kWh	1.715 ¢ Per kWh
Mid-Peak	3.706 ¢ Per kWh	3.706 ¢ Per kWh
On-Peak	0.000 ¢ Per kWh	5.150 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.059 ¢ Per kWh	0.059 ¢ Per kWh
Energy Efficiency	0.156 ¢ Per kWh	0.156 ¢ Per kWh
Regulatory Charge	$2.92 Per Billed kW	$2.92 Per Billed kW

Time-Of-Use Periods

	Billing Months October through May
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 10:00 P.M. every day
On-Peak hours	None

	Billing Months June through September
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 2:00 P.M. and 8:00 P.M. – 10:00 P.M. Monday – Friday 6:00 A.M. – 10:00 P.M. Saturday – Sunday
On-Peak hours	2:00 P.M. – 8:00 P.M. Monday – Friday

GreenChoice® Option

Customers who qualify for service on this rate may choose to participate in Austin Energy's GreenChoice renewable energy program as described in the *GreenChoice® Energy Rider*.

Terms and Conditions

Billing Demand and Power Factor Adjustment: Billing Demand before power factor correction shall be the kilowatt demand during the 15-minute interval of greatest use during the current billing month as indicated or recorded by metering equipment installed by Austin Energy. When power factor during the interval of greatest use is less than 90 percent as indicated or recorded by metering equipment installed by Austin Energy, Billing Demand shall be determined by multiplying kilowatt demand during the 15-minute interval of greatest use by 90 percent and dividing by the indicated or recorded power factor during the interval of greatest use.

TRANSMISSION VOLTAGE

Application

This rate is applicable to electric service required by any customer served at a transmission voltage (greater than 69,000 volts - nominal) to whom no other specific rate applies or as determined by Austin Energy. This rate shall be applied for a term of not less than 12 months following the month in which the criteria are met.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin which may be amended from time to time. Electric service of one standard character will be delivered to one point of service on the customer's premise and measured through one meter.

Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$2,500.00 Per Month	$2,500.00 Per Month
Electric Delivery	$0.00 Per Billed kW	$0.00 Per Billed kW
Demand Charge	$12.00 Per Billed kW	$13.00 Per Billed kW
Energy Charge	3.243 ¢ Per kWh	3.466 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.053 ¢ Per kWh	0.053 ¢ Per kWh
Energy Efficiency	0.139 ¢ Per kWh	0.139 ¢ Per kWh
Regulatory Charge	$2.49 Per Billed kW	$2.49 Per Billed kW

Time-Of-Use Option

In lieu of the charges above, customers may choose the following time-of-use charges to be applied for a term of not less than 12 consecutive billing months. Customers selecting this time-of-use option shall permit Austin Energy to install all equipment necessary for time-of-use metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. This option shall be limited to the greater of: 1) 10 percent of the customers in this rate class or, 2) the first 10 customers who request enrollment. A waiting list will be maintained and will be filled as customers select to opt out of time-of-use-service.

PROPOSED CITY OF AUSTIN ELECTRIC RATE SCHEDULE

Time-Of-Use Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$2,500.00 Per Month	$2,500.00 Per Month
Electric Delivery	$0.00 Per Billed kW	$0.00 Per Billed kW
Demand		
On-Peak	$0.00 Per Billed kW	$12.48 Per Billed kW
Mid-Peak	$11.08 Per Billed kW	$0.00 Per Billed kW
Energy		
Off-Peak	1.693 ¢ Per kWh	1.693 ¢ Per kWh
Mid-Peak	3.659 ¢ Per kWh	3.659 ¢ Per kWh
On-Peak	0.000 ¢ Per kWh	5.084 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.053 ¢ Per kWh	0.053 ¢ Per kWh
Energy Efficiency	0.139 ¢ Per kWh	0.139 ¢ Per kWh
Regulatory Charge	$2.49 Per Billed kW	$2.49 Per Billed kW

Time-Of-Use Periods

	Billing Months October through May
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 10:00 P.M. every day
On-Peak hours	None

	Billing Months June through September
Off-Peak Hours	10:00 P.M. – 6:00 A.M. every day
Mid-Peak Hours	6:00 A.M. – 2:00 P.M. and 8:00 P.M. – 10:00 P.M. Monday – Friday 6:00 A.M. – 10:00 P.M. Saturday – Sunday
On-Peak hours	2:00 P.M. – 8:00 P.M. Monday – Friday

GreenChoice® Option

Customers who qualify for service on this rate may choose to participate in Austin Energy's GreenChoice renewable energy program as described in the *GreenChoice® Energy Rider*.

Terms and Conditions

Billing Demand and Power Factor Adjustment: Billing Demand before power factor correction shall be the kilowatt demand during the 15-minute interval of greatest use during the current billing month as indicated or recorded by metering equipment installed by Austin Energy. When power factor during the interval of greatest use is less than 90 percent as indicated or recorded by metering equipment installed by Austin Energy, Billing Demand shall be determined by multiplying kilowatt demand during the 15-minute interval of greatest use by 90 percent and dividing by the indicated or recorded power factor during the interval of greatest use.

LIGHTING

Customer-Owned, Non-Metered Lighting

Application

This rate is applicable to non-metered electric service required by the Texas Department of Transportation for sign lighting and safety illumination at various locations in the City of Austin Electric Utility service area as agreed by the Texas Department of Transportation and the City of Austin

The contract with the State of Texas, dated August 22, 1995, as amended effective October 1, 2002, is incorporated by reference into this tariff.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin, which may be amended from time to time.

Charges

	Billing Months October through May	Billing Months June through September
Energy Charge	9.366 ¢ Per kWh	9.376 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.095 ¢ Per kWh	0.095 ¢ Per kWh
Energy Efficiency	0.250 ¢ Per kWh	0.250 ¢ Per kWh
Regulatory Charge	0.095 ¢ Per kWh	0.095 ¢ Per kWh

Customer-Owned, Metered Lighting

Application

This rate is applicable to electric service required by metered athletic field accounts whose connected load is more than 85 percent attributable to lighting as verified by the City of Austin.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin, which may be amended from time to time. Electric service of one standard character will be delivered to one point of service on the customer's premise and measured through one meter.

Charges

	Billing Months October through May	Billing Months June through September
Customer Charge	$15.00 Per Month	$15.00 Per Month
Energy Charge	16.701 ¢ Per kWh	18.201 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.065 ¢ Per kWh	0.065 ¢ Per kWh
Service Area Lighting	0.180 ¢ Per kWh	0.180 ¢ Per kWh
Energy Efficiency	0.473 ¢ Per kWh	0.473 ¢ Per kWh
Regulatory Charge	0.318 ¢ Per kWh	0.318 ¢ Per kWh

Service Area Street and Traffic Lighting

Application

This rate is applicable to electric service required for the illumination and operation of traffic signals on all public streets, highways, and expressways or thoroughfares within the city limits of Austin or any other incorporated area or municipal utility district requesting street lighting service. This rate is also applicable for the illumination of any property owned, operated, and/or maintained by the City of Austin.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin, which may be amended from time to time.

Charges

	Billing Months October through May	Billing Months June through September
Energy Charge	30.361 ¢ Per kWh	30.361 ¢ Per kWh
Energy Adjustment	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Community Benefit Charge		
Customer Assistance Program	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Energy Efficiency	0.803 ¢ Per kWh	0.803 ¢ Per kWh
Regulatory Charge	0.093 ¢ Per kWh	0.093 ¢ Per kWh

Austin Energy-Owned Outdoor Lighting

Application

This rate is applicable to electric service required by non-metered outdoor lighting installed, owned, operated, and maintained by the City of Austin. Lights are subject to availability.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin, which may be amended from time to time.

Charges

	Billing Months October through May	Billing Months June through September
Fixture Charge		
100 Watt High Pressure Sodium	$11.00 Per Month/Fixture	$11.00 Per Month/Fixture
175 Watt Mercury Vapor	$19.00 Per Month/Fixture	$19.00 Per Month/Fixture
250 Watt High Pressure Sodium	$28.50 Per Month/Fixture	$28.50 Per Month/Fixture
400 Watt Mercury Vapor	$44.50 Per Month/Fixture	$44.50 Per Month/Fixture

GreenChoice® ENERGY RIDER

Section I – Customers Enrolled Following The Initial Effective Date Of This Tariff

Application

For customers who subscribe on or after the initial effective date of this tariff:
The charges set forth in this rider apply to customers who choose to subscribe to Austin Energy's GreenChoice® product offerings. Subscribing customers will assist Austin Energy in adding renewable energy resources by paying a GreenChoice Adjustment as provided by this rider. The GreenChoice Price is based on a portfolio of renewable energy resources as procured by Austin Energy and made available for retail sale at its sole discretion. Energy surplus from expiring subscriptions or through attrition may also be made available for retail sale at the sole discretion of Austin Energy.

The GreenChoice Price and GreenChoice Adjustment as stipulated in this rider is calculated on an annual basis and put into effect on April 1, 2012, and January 1 of each calendar year thereafter. Under the terms of this rider, GreenChoice participants pay a GreenChoice Adjustment, in lieu of the fuel portion of the energy charge or energy adjustment (if applicable), on all energy consumed on meters covered under customer's subscription. Each year's offering will take into account any renewable energy added to the GreenChoice portfolio inventory and priced accordingly as described below.

GreenChoice is sold on the basis of individual annual offerings at a GreenChoice Price set as fixed for a number of years. Subscribers will be identified in terms of year of initial subscription or renewal (as applicable), for example GC2012 for subscriptions based on the offering initiated in 2012, GC2013 for 2013, and so on.

Fixed Price and Fixed Term

The price of each annual GreenChoice® offering will be fixed for a number of years. Both the price and the number of years for which it is fixed can vary with each new annual offering.

GreenChoice Price and GreenChoice Adjustment

The GreenChoice Price consists of components that will be fixed during the length of term established and subscribed by each customer and tied to each annual product offering. This price will not change during the life of the subscription. The fixed GreenChoice Price is based on two components: 1) cost of the renewable supply, including transmission and delivery costs, and any applicable ERCOT charges; and 2) administrative, marketing, and general revenue costs associated with the program.

The GreenChoice Price is determined on an annual basis and offerings are released for sale on April 1, 2012, and January 1 each year thereafter.

While the GreenChoice Price is fixed, subscribers will be subject to a "GreenChoice Adjustment" which is the result of a calculation that takes into account: (1) the fixed GreenChoice Price, (2) subtraction of any charges related to fuel, and (3) proration to exclude any system renewable energy not allocated to other GreenChoice subscribers.

Treatment of GreenChoice® Adjustment

The GreenChoice Adjustment is calculated as:

GreenChoice Adjustment = GreenChoice Price – Fuel Charges * SRS Adjustment (see below)

Where *Fuel Charges* are any costs associated with fuel used in non-renewable electricity production, and the *SRS Adjustment Factor* (explained below) is a percentage (0%-100%) which takes into account the difference between System Renewable Energy as described below and energy allocated to GreenChoice subscriptions.

System Renewable Supply Adjustment (SRS)

The System Renewable Supply Adjustment Factor (SRS) is expressed as a percentage and is defined as 100 minus the difference between *Community Supply* and *GreenChoice® Supply*.

Community Supply (CS) is defined as all energy produced from all renewable energy sources which are owned and operated by Austin Energy and/or interconnected to the Austin Energy electric distribution system and metered, including customer-owned generation, city-owned generation, Austin Energy-owned generation not allocated to the GreenChoice program, and renewable energy associated with GreenChoice subscriptions. Community Supply is expressed as a percentage of total retail sales to Austin Energy customers, and calculated on an annual basis.

GreenChoice® Supply (GS) is defined as energy attributable to GreenChoice customer subscriptions, including subscriptions initiated before April 1, 2012, expressed as a percentage of total retail sales to Austin Energy customers, and calculated on an annual basis.

The formula for determining the GreenChoice Adjustment, including the SRS adjustment is as follows:

GreenChoice Price	GCP_1	(¢/kWh)
Fuel Charges	FC	(¢/kWh)
Subtotal (GCP_1-FC)	GCP_2	(¢/kWh)

SRS% = 100% – [Community Supply (CS) % - GreenChoice Supply (GS) %]

GreenChoice Adjustment (¢/kWh) = (GCP_2 X SRS) x Monthly Consumption (kWh)

The GreenChoice Adjustment may change on an annual basis as fuel adjustments are incurred or there are changes in either Community Supply or GreenChoice Supply.

Section II – Customers Enrolled Prior To The Initial Effective Date Of This Tariff

Application

The following terms and charges set forth in this rider apply to customers who subscribed to the GreenChoice® program **prior** to the initial effective date of this tariff. New customers will take service under Section I of this tariff.

By subscribing to the GreenChoice program, participants will assist Austin Energy in adding renewable energy resources by paying a GreenChoice Adjustment as provided by this rider. The Batch-3 GreenChoice Adjustment applies to those customers who subscribed in writing to the GreenChoice program after the Batch-2 dates, but before April 22, 2005. The Batch-4 GreenChoice Adjustment applies to those customers who subscribe to the GreenChoice program after the Batch-3 dates, but before March 31, 2006. The Batch-5 GreenChoice Adjustment applies to those customers who subscribed to the GreenChoice program after January 14, 2008. The Batch-6 GreenChoice Adjustment applies to those customers who subscribed to the GreenChoice program after January 1, 2009, but before the initial effective date of this tariff.

Customers subscribed to the GreenChoice program under this section pay a GreenChoice® Adjustment, rather than the fuel portion of the energy charge and energy adjustment (if applicable), on that portion of their monthly energy use that is designated as GreenChoice energy. Subscriptions to the GreenChoice program shall continue for the full term of this rider unless terminated sooner in accordance with the terms of this rider. Aside from the GreenChoice Adjustment, participants' usage will be priced in accordance with all applicable rate tariffs and riders governing participant's electric service.

Participant subscriptions under this rider support Austin Energy's acquisitions of renewable energy. This energy cannot be directed to any one particular destination on the ERCOT electric grid, including participant premises. Participant subscriptions may be satisfied by Renewable Energy Credits (RECs) as provided for in the Public Utility Regulatory Act. The availability of energy from the renewable sources serving this program may vary from time to time and is dependent upon weather conditions, unexpected circumstances, and third-party actions for which Austin Energy cannot be responsible. This may produce periodic shortfalls of GreenChoice energy available for retail sale, or subscription, during the term of this rider.

Participation in the GreenChoice program is contingent upon the participant remaining an Austin Energy customer for the duration of the GreenChoice program as set forth by this rider. If participant's electric service is involuntarily terminated by Austin Energy or if participant discontinues electric service and relocates outside of the Austin Energy service area, participation in the GreenChoice program shall end immediately. If participant relocates to another premise within Austin Energy's service area, participant may cancel participation within 15 days of the relocation. If participant chooses another electric provider after any deregulation of the Austin electric retail market, Austin Energy may terminate participant's participation in this program at Austin Energy's sole discretion. Subscriptions are not transferable from customer to customer.

Character of Service

Each GreenChoice participant will receive electric service under the applicable service tariff.

Residential Service and General Service Non-Demand:

Batch-3 GreenChoice Price:	\$0.0330 per kWh
Batch-4 GreenChoice Price:	\$0.0350 per kWh
Batch-5 GreenChoice Price:	\$0.0550 per kWh
Batch-6 GreenChoice Price:	\$0.0570 per kWh

With respect to customers classified as residential service and general service non-demand participants at the time in which they were enrolled, the GreenChoice® Adjustment will be applied to the participant's entire monthly consumption until December 31, 2013, for Batch-3, until June 30, 2015, for Batch-4, until December 31, 2022, for Batch-5, and until December 31, 2014, for Batch-6. In order to participate in the GreenChoice program under this rider, a customer classified at the time of enrollment as residential service or general service non-demand must be fully subscribed to the program as required by Austin Energy.

Large Commercial and Industrial Service:

Batch-3 GreenChoice Price:	\$0.0330 per kWh
Batch-4 GreenChoice Price:	\$0.0350 per kWh
Batch-5 GreenChoice Price:	\$0.0550 per kWh
Batch-6 GreenChoice Price:	\$0.0570 per kWh

All eligible customers other than residential service or non-demand customers are subject to the conditions of their written agreement with Austin Energy that either specifies a monthly quantity of GreenChoice energy or designates 100 percent of the customer's monthly energy consumption as GreenChoice usage. The resulting monthly portion of the participant's consumption will be subject to the applicable GreenChoice Adjustment for the term of the agreement until December 31, 2013, for Batch-3, June 30, 2015, for Batch-4, December 31, 2022, for Batch-5, and December 31, 2014, for Batch-6.

NET METERING RENEWABLE RESOURCES RIDER

Application

This Rider is available to any retail customer receiving electric service under a City of Austin electric rate schedule who owns and operates an on-site generating system powered by a renewable resource capable of producing not more than 20 kW of power, and who interconnects with the City of Austin's electric system. Renewable energy technology is any technology that exclusively relies on any energy source that is naturally regenerated over a short time and derived directly from the sun, or from moving water or other natural movements and mechanisms of the environment. Renewable energy technologies include those that rely on energy derived directly from the sun, on 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. This Rider applies to a customer-owned generating system that primarily offsets part or all of the customer's electric service provided by the City of Austin.

Terms and Conditions

1. All charges, character of service, and terms and conditions of the City of Austin Electric Rate Schedule under which the customer receives service apply except as expressly altered by this Rider.

2. The customer shall comply with the current City of Austin technical requirements for distributed generation interconnection for facilities under 20 kW and any revisions to the requirements. The customer shall obtain approval from the City of Austin before the customer energizes the customer's on-site generating system or interconnects it with the City of Austin's electric system. If the customer is a participant in the Austin Energy Solar Rebate Program, the customer shall comply with the guidelines of that program. The customer shall submit to the City a completed interconnection application form and signed agreement. The minimum term of an agreement under this Rider is one year, extended automatically unless terminated by either party with 60 days written notice. If the customer is a participant in the Austin Energy Solar Rebate Program, the minimum term of the agreement is the period required by that Program.

3. The customer is responsible for the costs of interconnecting with the City of Austin's electric system, including transformers, service lines, or other equipment determined necessary by the City for safe installation and operation of the customer's equipment with the City's system. The customer is responsible for any costs associated with required inspections and permits.

Metering

Metering under this Rider shall be performed by a single meter capable of registering the flow of electricity in two directions (delivered to and received from the customer) to determine the customer's net energy flow.

Net Energy

1. In a billing month after a customer receives approval from the City of Austin to interconnect the customer's on-site generating system, the energy received from the customer's approved system to the City of Austin's electric system as recorded on Austin Energy metering equipment shall be

subtracted from the amount of energy delivered by the City of Austin electric system to the customer as recorded on Austin Energy's metering equipment. The result of this calculation shall be the monthly net energy (kWh).

2. The monthly net energy as calculated in (1.) above shall be the billing determinant for all charges collected on a per kWh basis in the customer's rate schedule. If the monthly net energy is greater than zero, the customer shall be billed in accordance with their rate schedule, if the monthly net energy is less than zero, the customer shall be credited as follows:

   Monthly Net Energy (kWh) x (-1) x Current Value of Solar Rate (¢/kWh) = Monthly Credit

3. Any charges in the customer's rate schedule not collected on a kWh basis are not altered by this calculation.

4. Any credit shall be applied to the utility charges due from the customer to the City of Austin.

THERMAL ENERGY STORAGE

Application

This rider is applicable to any customer taking service under a rate schedule that applies a Demand Charge on a per kilowatt basis and who shifts to off-peak periods no less than the lesser of 20 percent of the customer's normal on-peak June through September billed demand or 2,500 kilowatts through the use of thermal energy storage technology. The normal on-peak June through September billed demand shall be the maximum June through September billed demand recorded prior to attaching this rider, or as may be determined by the City of Austin.

Rate

The customer shall continue to be billed under the applicable current rate schedule with the following provisions:

June through September Billed Demand: From billing months June through September, the billed demand shall be the highest 15-minute demand recorded during the on-peak period. The June through September billed demand shall not be less than 50 percent of the normal on-peak June through September billed demand. If more than 50 percent of the customer's load is attributable to cooling, the 50 percent floor will be waived.

October through May Billed Demand: From billing months October through May, the billed demand shall be the highest 15-minute demand recorded during the month, or 90 percent of the June through September billed demand set in the previous June through September billing months; whichever is less.

On-Peak: 4:00 p.m. to 8:00 p.m., Monday through Friday, June 1 through September 30, or 3:00 p.m. to 7:00 p.m., Monday through Friday, June 1 through September 30.

Off-Peak: 8:00 p.m. to 4:00 p.m., Monday through Friday, all day Saturday, Sunday, Memorial Day, Independence Day, and Labor Day, June 1 through September 30; or 7:00 p.m. to 3:00 p.m., Monday through Friday, all day Saturday, Sunday, Memorial Day, Independence Day, and Labor Day, June 1 through September 30. And, all day October 1 through May 31.

Conditions of Service:

A. The customer shall enter into a separate agreement with the City of Austin for this rider.

B. The customer shall continue to be served under the terms and conditions of, and shall continue to comply with, all rules and regulations of the City of Austin as amended from time to time during the term of this agreement.

C. The on-peak load shall be shifted to off-peak, not eliminated, or replaced by alternative fuels.

D. The customer shall permit the City to install all equipment necessary for time-of-use metering and to permit reasonable access to all service facilities installed by the City for inspection, maintenance, repair, removal, or data recording purposes.

ENERGY ADJUSTMENT

Application

The Energy Adjustment (EA) provides for an adjustment to the energy (kWh) portion of the base rate to reflect changes in the variability of the net power supply or energy settlement costs (Net Settlement Cost). The adjustment reflects changes in Net Settlement Cost above or below the portion included in base energy rates and provides for (1) a periodic adjustment option or (2) an option to reset base rates to reduce the EA to zero as a corrective measure.

(1) The EA rate may be adjusted administratively by the General Manager unless the adjustment exceeds certain thresholds defined in (2).

(2) The EA rate will be reset to zero through a base rate change when it exceeds ($0.01) to $0.01 per kWh or when a base rate change that impacts the Energy charge is adopted.

Base Net Settlement Cost - The base Net Settlement Cost per kWh included in the Energy Charge is:

Secondary voltage service:	$0.03398
Primary voltage service:	$0.03321
Transmission voltage service:	$0.03279

Energy Adjustment - The energy adjustment may be increased or decreased based on changes in the Net Settlement Cost which is composed of the following and calculated based on the projected net cost per kWh of :

- ERCOT Load Zone expense – Load zone weighted cost to serve Austin Energy load
- Direct Fuel, Hedging and Purchased Power Agreements (PPA) cost
- Generation/PPA revenue – Revenue from Austin Energy generation units or assets that Austin Energy has contracted
- Ancillary Service cost – Cost to meet ancillary service obligations to serve the load.
- Ancillary Service revenue – Revenue from Austin Energy generation units by providing ancillary services to the market
- Net revenue generated by congestion revenue rights

STANDBY CAPACITY

Application

This rate is applicable to any customer who has on-site power-production facilities, receives power at the primary voltage level 12,500 volts (nominal) or higher, has dedicated service directly from a City of Austin substation, and executes a separate contract with the City of Austin for standby electric service. This rate schedule is closed to new customers.

Character of Service

The character of service provided under this rate shall be alternating current, 60 cycles, single-phase or three-phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin which may be amended from time to time. Electric service of one standard character will be delivered to one point of service on the customer's premise and measured through one meter.

The contract with the State of Texas, dated August 22, 1995, as amended effective October 1, 2002, is incorporated by reference into this tariff.

Monthly Standby Capacity Rate:

- $2.62 per kilowatt of Primary Voltage Standby Capacity
- $2.23 per kilowatt of Primary Voltage Standby Capacity – State of Texas accounts
- $2.41 per kilowatt of Transmission Voltage Standby Capacity
- $1.91 per kilowatt of Transmission Voltage Standby Capacity – State of Texas accounts

Standby Capacity:

The Standby Capacity will be equivalent to the maximum demand of the load to be served by the City of Austin during a scheduled or unscheduled outage of the customer's power production facilities or as stipulated in the contract between the City of Austin and the customer.

Minimum Bill:

Customer will be assessed a monthly Minimum Bill equal to the Standby Capacity Rate times the Standby Capacity.

LARGE PRIMARY SERVICE – SPECIAL CONTRACT RIDER II

Definitions

FULL REQUIREMENTS service means full and exclusive generation, transmission, and distribution, (i.e., "bundled") service as presently supplied by City of Austin (sometimes referred to as City) 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 condition of the City of Austin's Distributed generation from Renewable Sources Rider.

Application

This rate applies to a large primary service (LPS) customer that executes a separate contract for this service on or after October 9, 2006, in form and substance acceptable to the City of Austin. The contract will require the customer to remain a full requirements customer of the City of Austin through May 31, 2015, on which date customer's contract and the terms of this rider shall terminate; provided, however, that if the City of Austin subsequently adopts a tariff that provides more favorable rates, terms, or conditions than provided by this rider and which describes a customer class for which customer's large primary service accounts qualify, customer may terminate its contract and receive service pursuant to such subsequent tariff. The City of Austin, acting by and through it Electric Utility Department, 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 the City of Austin. This rate schedule is closed to new customers. The Rider TOU – Thermal Energy Storage and the Optional Time-of-Use Rate may be attached to this rate.

Character of Service

The Character of Service provided under this rate is alternating current, 60 cycles, single phase, or three phase, in accordance with the Utilities Criteria Manual prescribed by the City of Austin and which may be amended from time to time. Electric service of one standard character will be delivered to one point on the customer's premises and measured through one meter.

Charges

	Billing Months May through October	**Billing Months November through April**
Customer Charge	$0.00 Per Month	$0.00 Per Month
Electric Delivery	$0.00 Per Billed kW	$0.00 Per Billed kW
Demand Charge	$12.54 Per Billed kW	$11.40 Per Billed kW
Energy Charge	1.110 ¢ Per kWh	1.110 ¢ Per kWh
Community Benefit Charge	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Regulatory Charge	0.000 ¢ Per kWh	0.000 ¢ Per kWh

Fuel Adjustment Clause (FAC) – plus an adjustment for variable costs, calculated according to the Fuel Adjustment Clause Tariff, multiplied by all kWh.

Minimum Bill:

Customer will be assessed a monthly Minimum Bill of $12.00 if the above calculations result in a charge of less than $12.00.

Billing Demand:

The kilowatt demand during the 15-minute interval of greatest use during the current billing month as indicated or recorded by metering equipment installed by the City of Austin. 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 tariff or ordinance governing power factor that may be enacted or amended by the City of Austin from time to time.

Optional Time-Of-Use Rate:

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. The customer shall permit the City to install all equipment necessary for time-of-use metering and to permit reasonable access to all electric service facilities installed by the City for inspection, maintenance, repair, removal, or data recording purposes.

	Billing Months May through October	**Billing Months November through April**
Customer Charge	$0.00 Per Month	$0.00 Per Month
Electric Delivery	$0.00 Per Billed kW	$0.00 Per Billed kW
Demand Charge	$12.54 Per Billed kW	$11.40 Per Billed kW
Energy Charge		
Off-Peak	0.560 ¢ Per kWh	1.710 ¢ Per kWh
On-peak	2.410 ¢ Per kWh	(0.290) ¢ Per kWh
Community Benefit Charge	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Regulatory Charge	0.000 ¢ Per kWh	0.000 ¢ Per kWh

Billing demand will be based on the 15-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 Billing Demand).

Fuel Adjustment Clause (FAC) – plus an adjustment for variable costs, calculated according to the Fuel Adjustment Clause Tariff, multiplied by all kWh.

On-Peak: 1:00 p.m. to 9:00 p.m., Monday through Friday, May 1 through October 31; 8:00 a.m. to 10:00 p.m., Monday through Sunday, November 1 through April 30.

Off-Peak: 9:00 p.m. to 1:00 p.m., Monday through Friday, all day Saturday, Sunday, Memorial Day, Independence Day, and Labor Day; May 1 through October 31; 10:00 p.m. to 8:00 a.m., Monday through Sunday, November 1 through April 30.

Terms and Conditions

The special contract rate is effective on the first day of the customer's billing cycle following the date that a separate contract under this tariff has been executed between the City of Austin and the customer, and shall be in effect through May 31, 2015.

Notwithstanding any provision of this tariff, neither customer nor the City of Austin shall be precluded from challenging the legal validity of any statute, regulations, or other provisions of the law.

This Special Contract Rider shall be extended to all of an LPS customer's accounts having a maximum demand of at least 500 kW.

Upon request, customers receiving service under this Special Contract Rider will be provided dual feed service with reserve capacity and maintenance under the long term contract provisions of the Special 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 the City of Austin that the customer violated the provisions of this tariff or the contract implementing the tariff, then the customer will be immediately billed on the LPS rate schedule, or as amended, from the date service was first commenced under this tariff. 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 this tariff, shall immediately become due by customer to the City of Austin.

The contract executed under this tariff shall address the rights of the City and the customer relating to the transfer or assignment of rights under this tariff.

LARGE PRIMARY SERVICE SPECIAL CONTRACT – INDUSTRIAL RIDER

Application

This rate applies to electric service to any customer that qualifies for service and has executed a contract under the Large Primary Service – Special Contract Rider I or II and thereafter has (1) reached a billing demand of at least 25,000 kilowatts during any two months within the previous six months, and (2) maintained an average load factor of at least 85 percent during the previous six months. Any action by the customer resulting in measurable reduction in peak demand or energy use may be taken into account the City, in its sole discretion, when applying the demand and load factor requirements of this tariff. The City will also take into account up to 500 kilowatts of power generated by customer-owned, on-site renewable energy technology in accordance with the Distributed Generation from Renewable Sources Rider, when applying the demand requirement.

The customer shall continue to receive service under the Large Primary Service – Special Contract Rider I or II tariff, as applicable, and comply with terms of its Large Primary Service Special Contract; provided, that customer at its option shall receive the energy and billing demand rates specified by this Rider for accounts which meet criteria (1) and (2) above, so long as this Rider remains in effect. This rate schedule is closed to new customers.

The Rider TOU – Thermal Energy Storage and the Optional Time-of-Use Rate may be attached to this rate.

Charges

	Billing Months May through October	Billing Months November through April
Customer Charge	$0.00 Per Month	$0.00 Per Month
Electric Delivery	$0.00 Per Billed kW	$0.00 Per Billed kW
Demand Charge	$12.23 Per Billed kW	$11.12 Per Billed kW
Energy Charge	1.080 ¢ Per kWh	1.080 ¢ Per kWh
Community Benefit Charge	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Regulatory Charge	0.000 ¢ Per kWh	0.000 ¢ Per kWh

Fuel Adjustment Clause (FAC) – plus an adjustment for variable costs, calculated according to the Fuel Adjustment Clause Tariff, multiplied by all kWh.

Optional Time-Of-Use Rate:

	Billing Months May through October	**Billing Months November through April**
Customer Charge	$0.00 Per Month	$0.00 Per Month
Electric Delivery	$0.00 Per Billed kW	$0.00 Per Billed kW
Demand Charge	$12.23 Per Billed kW	$11.12 Per Billed kW
Energy Charge		
Off-Peak	0.550 ¢ Per kWh	1.670 ¢ Per kWh
On-Peak	2.350 ¢ Per kWh	(0.300) ¢ Per kWh
Community Benefit Charge	0.000 ¢ Per kWh	0.000 ¢ Per kWh
Regulatory Charge	0.000 ¢ Per kWh	0.000 ¢ Per kWh

Billing demand will be based on the 15-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 Billing Demand).

Fuel Adjustment Clause (FAC) – plus an adjustment for variable costs, calculated according to the Fuel Adjustment Clause Tariff, multiplied by all kWh.

On-Peak: 1:00 p.m. to 9:00 p.m., Monday through Friday, May 1 through October 31; 8:00 a.m. to 10:00 p.m., Monday through Sunday, November 1 through April 30.

Off-Peak: 9:00 p.m. to 1:00 p.m., Monday through Friday; all day Saturday, Sunday, Memorial Day, Independence Day, and Labor Day, May 1 through October 31; 10:00 p.m. to 8:00 a.m., Monday through Sunday, November 1 through April 30.

COMMUNITY BENEFIT CHARGE

Application

The Community Benefit Charge recovers certain costs incurred by the utility as a benefit to AE's customers and the greater community. This charge includes three specific programs and services provided to customers throughout AE's service area. This includes the following programs:

Customer Assistance Program- The Customer Assistance Program funds programs including bill assistance to support low-income and other disadvantaged customers.

Service Area Lighting- The Service Area Lighting charge recovers the cost of street lighting enjoyed by customers throughout the entire AE service territory.

Energy Efficiency- The Energy Efficiency charge recovers the cost of energy efficiency, green building, and solar rebate programs offered by AE throughout the entire service territory.

REGULATORY CHARGE

Application

The Regulatory Charge recovers ERCOT transmission service charges incurred by the City and regulatory fees or penalties required by law, including ERCOT administrative charges required for load serving entities to participate in the Nodal market.

The Regulatory Charge may be adjusted administratively by the General Manager to reflect any change made to the annual ERCOT wholesale transmission service charge matrix and changes to regulatory fees or penalties.

Appendix F: Proposed Residential Customer Billing Impacts

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Residential

Unbundled 5-Tier Inclining Block Energy Rate

(A) Line No.	(B) kWh per month	(C) No. of Bills	(D) % of Total	(E) Cum. % of Total	(F) Est. kW per Month	(G) Bill at Current Rates	(H) Cents per kWh	(I) Bill at Cost of Service	(J) Percent Change	(K) Cents per kWh	(L) Bill at Proposed Rates	(M) Dollar Change	(N) Percent Change	(O) Cents per kWh
Annual														
1	0 & below	24,832	0.6%	0.6%	-	$6.00		$35.82	497.0%		$25.00	$19.00	316.7%	
2	1-250 kWh	494,482	11.5%	12.1%	0.6	14.68	0.11748	45.33	208.7%	0.36263	32.48	17.80	121.2%	0.25988
3	251-500 kWh	839,585	19.6%	31.7%	1.7	32.05	0.08548	64.34	100.7%	0.17158	47.45	15.40	48.0%	0.12654
4	501-750 kWh	810,857	18.9%	50.6%	2.9	53.64	0.08582	83.35	55.4%	0.13337	66.76	13.12	24.5%	0.10681
5	751-1000 kWh	614,888	14.3%	64.9%	4.0	79.43	0.09078	102.37	28.9%	0.11699	90.39	10.96	13.8%	0.10331
6	1001-1250 kWh	441,298	10.3%	75.2%	5.1	105.23	0.09353	121.38	15.4%	0.10789	116.74	11.51	10.9%	0.10377
7	1251-1500 kWh	312,053	7.3%	82.5%	6.3	131.02	0.09529	140.39	7.2%	0.10211	145.79	14.77	11.3%	0.10603
8	1501-1750 kWh	220,364	5.1%	87.6%	7.4	156.82	0.09650	159.41	1.7%	0.09810	176.47	19.65	12.5%	0.10860
9	1751-2000 kWh	152,513	3.6%	91.2%	8.6	182.61	0.09739	178.42	-2.3%	0.09516	208.77	26.16	14.3%	0.11134
10	2001-2500 kWh	179,112	4.2%	95.4%	10.3	221.30	0.09836	206.94	-6.5%	0.09197	257.23	35.92	16.2%	0.11432
11	2501-3000 kWh	86,261	2.0%	97.4%	12.6	272.89	0.09923	244.97	-10.2%	0.08908	324.00	51.11	18.7%	0.11782
12	3001-3500 kWh	44,346	1.0%	98.4%	14.8	324.48	0.09984	282.99	-12.8%	0.08708	392.94	68.46	21.1%	0.12090
13	3501-4000 kWh	24,588	0.6%	99.0%	17.1	376.07	0.10029	321.02	-14.6%	0.08561	461.88	85.81	22.8%	0.12317
14	4001 & higher	44,178	1.0%	100.0%	18.3	401.86	0.10047	340.03	-15.4%	0.08501	496.35	94.48	23.5%	0.12409
		4,289,357												

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Residential (Low Income)

Unbundled Five Inclining Block Energy Rate

(A) Line No.	(B) kWh per month	(C) No. of Bills	(D) % of Total	(E) Cum. % of Total	(F) Bill at Current Rates	(G) Cents per kWh	(H) Bill at Cost of Service	(I) Percent Change	(J) Cents per kWh	(K) Bill at Proposed Rates	(L) Proposed Low Income Discount	(M) Bill Including Discount	(N) Dollar Change w/ Discount	(O) Percent Change	(P) Cents per kWh
Summer															
1	0 & below	62	0.3%	0.3%	$0.00		$35.82			$25.00	-$25.00	$0.00	$0.00		
2	1-250 kWh	500	2.1%	2.3%	6.56	0.05250	45.78	597.6%	0.36625	33.40	-25.00	8.40	1.84	28.1%	0.06723
3	251-500 kWh	1,545	6.4%	8.8%	19.69	0.05250	65.70	233.7%	0.17520	50.21	-25.00	25.21	5.52	28.1%	0.06723
4	501-750 kWh	2,630	11.0%	19.8%	38.15	0.06104	85.62	124.4%	0.13699	72.02	-25.00	47.02	8.87	23.2%	0.07523
5	751-1000 kWh	3,219	13.4%	33.2%	61.95	0.07080	105.54	70.4%	0.12062	98.83	-25.00	73.83	11.88	19.2%	0.08437
6	1001-1250 kWh	3,213	13.4%	46.6%	85.75	0.07622	125.46	46.3%	0.11152	128.76	-25.00	103.76	18.01	21.0%	0.09223
7	1251-1500 kWh	3,017	12.6%	59.2%	109.55	0.07967	145.38	32.7%	0.10573	161.82	-25.00	136.82	27.27	24.9%	0.09950
8	1501-1750 kWh	2,738	11.4%	70.6%	133.35	0.08206	165.30	24.0%	0.10172	196.75	-25.00	171.75	38.40	28.8%	0.10569
9	1751-2000 kWh	2,099	8.8%	79.4%	157.15	0.08381	185.22	17.9%	0.09878	233.56	-25.00	208.56	51.41	32.7%	0.11123
10	2001-2500 kWh	2,726	11.4%	90.8%	192.85	0.08571	215.10	11.5%	0.09560	288.77	-25.00	263.77	70.92	36.8%	0.11723
11	2501-3000 kWh	1,179	4.9%	95.7%	240.45	0.08744	254.94	6.0%	0.09270	364.88	-25.00	339.88	99.43	41.4%	0.12359
12	3001-3500 kWh	591	2.5%	98.2%	288.05	0.08863	294.78	2.3%	0.09070	443.50	-25.00	418.50	130.45	45.3%	0.12877
13	3501-4000 kWh	216	0.9%	99.1%	335.65	0.08951	334.62	-0.3%	0.08923	522.11	-25.00	497.11	161.46	48.1%	0.13256
14	4001 & higher	227	0.9%	100.0%	359.45	0.08986	354.54	-1.4%	0.08863	561.42	-25.00	536.42	176.97	49.2%	0.13411
		23,962													
Winter															
15	0 & below	155	0.4%	0.4%	$0.00		$35.82			$25.00	-$25.00	$0.00	$0.00		
16	1-250 kWh	3,949	10.4%	10.8%	6.56	0.05250	45.10	587.3%	0.36081	32.03	-25.00	7.03	0.46	7.1%	0.05620
17	251-500 kWh	9,506	25.1%	35.9%	19.69	0.05250	63.66	223.4%	0.16976	46.08	-25.00	21.08	1.39	7.1%	0.05620
18	501-750 kWh	8,645	22.8%	58.7%	35.90	0.05744	82.22	129.0%	0.13155	64.13	-25.00	39.13	3.23	9.0%	0.06260
19	751-1000 kWh	6,070	16.0%	74.7%	55.20	0.06309	100.78	82.6%	0.11518	86.18	-25.00	61.18	5.98	10.8%	0.06992
20	1001-1250 kWh	3,783	10.0%	84.7%	74.50	0.06622	119.34	60.2%	0.10608	110.73	-25.00	85.73	11.23	15.1%	0.07620
21	1251-1500 kWh	2,278	6.0%	90.7%	93.80	0.06822	137.90	47.0%	0.10029	137.78	-25.00	112.78	18.98	20.2%	0.08202
22	1501-1750 kWh	1,356	3.6%	94.3%	113.10	0.06960	156.46	38.3%	0.09628	166.33	-25.00	141.33	28.23	25.0%	0.08697
23	1751-2000 kWh	845	2.2%	96.5%	132.40	0.07061	175.02	32.2%	0.09335	196.38	-25.00	171.38	38.98	29.4%	0.09140
24	2001-2500 kWh	785	2.1%	98.6%	161.35	0.07171	202.86	25.7%	0.09016	241.45	-25.00	216.45	55.10	34.2%	0.09620
25	2501-3000 kWh	298	0.8%	99.4%	199.95	0.07271	239.98	20.0%	0.08727	303.56	-25.00	278.56	78.61	39.3%	0.10129
26	3001-3500 kWh	126	0.3%	99.7%	238.55	0.07340	277.10	16.2%	0.08526	367.66	-25.00	342.66	104.11	43.6%	0.10543
27	3501-4000 kWh	46	0.1%	99.8%	277.15	0.07391	314.22	13.4%	0.08379	431.76	-25.00	406.76	129.61	46.8%	0.10847
28	4001 & higher	58	0.2%	100.0%	296.45	0.07411	332.78	12.3%	0.08320	463.81	-25.00	438.81	142.36	48.0%	0.10970
		37,900													

Appendix G: Proposed Secondary Voltage Commercial Customer Billing Impacts

Austin Energy
2011 Electric System Rate Study

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Secondary Voltage (< 10 kW)

Unbundled Seasonal Demand Rate with $/kW Electric Delivery charge

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E) Number of Bills	(F) Cum. % of Bills	(G) Bill at E02 Rates	(H) Cents per kWh	(I) Bill at Cost of Service	(J) Percent Change	(K) Cents per kWh	(L) Bill at Proposed Rates	(M) Dollar Change	(N) Percent Change	(O) Cents per kWh
Summer														
1	0%	-	-	4,881	1.8%	$6.00		$27.77	362.8%		$18.00	$12.00	200.0%	
2	10%	219	3.0	25,228	11.1%	27.54	0.12578	92.22	234.8%	0.42111	48.02	20.47	74.3%	0.21926
3	20%	438	3.0	37,383	24.8%	49.09	0.11208	101.62	107.0%	0.23201	70.54	21.45	43.7%	0.16104
4	30%	657	3.0	37,683	38.6%	70.63	0.10751	111.02	57.2%	0.16898	93.05	22.42	31.7%	0.14163
5	40%	876	3.0	31,394	50.2%	92.18	0.10523	120.42	30.6%	0.13746	115.57	23.39	25.4%	0.13193
6	50%	1,095	3.0	50,402	68.7%	113.72	0.10386	129.82	14.2%	0.11856	138.09	24.36	21.4%	0.12611
7	60%	1,314	3.0	35,510	81.8%	135.27	0.10294	139.22	2.9%	0.10595	160.61	25.34	18.7%	0.12223
8	70%	1,533	3.0	14,701	87.2%	156.81	0.10229	148.62	-5.2%	0.09694	183.12	26.31	16.8%	0.11945
9	80%	1,752	3.0	9,568	90.7%	178.36	0.10180	158.01	-11.4%	0.09019	205.64	27.28	15.3%	0.11737
10	90%	1,971	3.0	11,684	95.0%	199.90	0.10142	167.41	-16.3%	0.08494	228.16	28.25	14.1%	0.11576
11	100%	2,190	3.0	13,693	100.0%	221.45	0.10112	176.81	-20.2%	0.08074	250.68	29.23	13.2%	0.11446
Winter														
12	0%	-	-	4,881	1.8%	$6.00		$27.77	362.8%		$18.00	$12.00	200.0%	
13	10%	219	3.0	25,228	11.1%	23.60	0.10778	88.17	273.6%	0.40262	44.03	20.43	86.6%	0.20107
14	20%	438	3.0	37,383	24.8%	41.21	0.09408	97.04	135.5%	0.22155	62.57	21.36	51.8%	0.14285
15	30%	657	3.0	37,683	38.6%	58.81	0.08951	105.90	80.1%	0.16119	81.10	22.29	37.9%	0.12344
16	40%	876	3.0	31,394	50.2%	76.41	0.08723	114.76	50.2%	0.13101	99.64	23.22	30.4%	0.11374
17	50%	1,095	3.0	50,402	68.7%	94.01	0.08586	123.62	31.5%	0.11290	118.17	24.16	25.7%	0.10792
18	60%	1,314	3.0	35,510	81.8%	111.62	0.08494	132.48	18.7%	0.10083	136.70	25.09	22.5%	0.10404
19	70%	1,533	3.0	14,701	87.2%	129.22	0.08429	141.35	9.4%	0.09220	155.24	26.02	20.1%	0.10126
20	80%	1,752	3.0	9,568	90.7%	146.82	0.08380	150.21	2.3%	0.08574	173.77	26.95	18.4%	0.09918
21	90%	1,971	3.0	11,684	95.0%	164.43	0.08342	159.07	-3.3%	0.08071	192.31	27.88	17.0%	0.09757
22	100%	2,190	3.0	13,693	100.0%	182.03	0.08312	167.93	-7.7%	0.07668	210.84	28.81	15.8%	0.09627

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Secondary Voltage (< 10 kW)

Unbundled Seasonal Demand Rate with $/kW Electric Delivery charge

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E) Number of Bills	(F) Cum. % of Bills	(G) Bill at E02 Rates	(H) Cents per kWh	(I) Bill at Cost of Service	(J) Percent Change	(K) Cents per kWh	(L) Bill at Proposed Rates	(M) Dollar Change	(N) Percent Change	(O) Cents per kWh
Summer														
1	0%	-	-	4,881	1.8%	$6.00		$27.77	362.8%		$18.00	$12.00	200.0%	
2	10%	657	9.0	25,228	11.1%	70.63	0.10751	221.13	213.1%	0.33657	108.05	37.42	53.0%	0.16446
3	20%	1,314	9.0	37,383	24.8%	135.27	0.10294	249.32	84.3%	0.18974	175.61	40.34	29.8%	0.13364
4	30%	1,971	9.0	37,683	38.6%	199.90	0.10142	277.52	38.8%	0.14080	243.16	43.25	21.6%	0.12337
5	40%	2,628	9.0	31,394	50.2%	264.54	0.10066	305.72	15.6%	0.11633	310.71	46.17	17.5%	0.11823
6	50%	3,285	9.0	50,402	68.7%	329.17	0.10021	333.91	1.4%	0.10165	378.26	49.09	14.9%	0.11515
7	60%	3,942	9.0	35,510	81.8%	393.81	0.09990	362.11	-8.0%	0.09186	445.82	52.01	13.2%	0.11309
8	70%	4,599	9.0	14,701	87.2%	458.44	0.09968	390.31	-14.9%	0.08487	513.37	54.93	12.0%	0.11163
9	80%	5,256	9.0	9,568	90.7%	523.08	0.09952	418.50	-20.0%	0.07962	580.92	57.84	11.1%	0.11053
10	90%	5,913	9.0	11,684	95.0%	587.71	0.09939	446.70	-24.0%	0.07555	648.47	60.76	10.3%	0.10967
11	100%	6,570	9.0	13,693	100.0%	652.35	0.09929	474.89	-27.2%	0.07228	716.03	63.68	9.8%	0.10898
Winter														
12	0%	-	-	4,881	1.8%	$6.00		$27.77	362.8%		$18.00	$12.00	200.0%	
13	10%	657	9.0	25,228	11.1%	58.81	0.08951	208.98	255.4%	0.31809	96.10	37.29	63.4%	0.14627
14	20%	1,314	9.0	37,383	24.8%	111.62	0.08494	235.57	111.1%	0.17928	151.70	40.09	35.9%	0.11545
15	30%	1,971	9.0	37,683	38.6%	164.43	0.08342	262.16	59.4%	0.13301	207.31	42.88	26.1%	0.10518
16	40%	2,628	9.0	31,394	50.2%	217.24	0.08266	288.74	32.9%	0.10987	262.91	45.67	21.0%	0.10004
17	50%	3,285	9.0	50,402	68.7%	270.04	0.08221	315.33	16.8%	0.09599	318.51	48.47	17.9%	0.09696
18	60%	3,942	9.0	35,510	81.8%	322.85	0.08190	341.91	5.9%	0.08674	374.11	51.26	15.9%	0.09490
19	70%	4,599	9.0	14,701	87.2%	375.66	0.08168	368.50	-1.9%	0.08013	429.71	54.05	14.4%	0.09344
20	80%	5,256	9.0	9,568	90.7%	428.47	0.08152	395.09	-7.8%	0.07517	485.32	56.84	13.3%	0.09234
21	90%	5,913	9.0	11,684	95.0%	481.28	0.08139	421.67	-12.4%	0.07131	540.92	59.64	12.4%	0.09148
22	100%	6,570	9.0	13,693	100.0%	534.09	0.08129	448.26	-16.1%	0.06823	596.52	62.43	11.7%	0.09079

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Secondary Voltage (< 10 kW)

Unbundled Seasonal Demand Rate with $/kW Electric Delivery charge

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E) Number of Bills	(F) Cum. % of Bills	(G) Bill at E01C Rates	(H) Cents per kWh	(I) Bill at Cost of Service	(J) Percent Change	(K) Cents per kWh	(L) Bill at Proposed Rates	(M) Dollar Change	(N) Percent Change	(O) Cents per kWh
Summer														
1	0%	-	-	-	0.0%	$6.00		$27.77	362.8%		$18.00	$12.00	200.0%	
2	10%	219	3.0	804	59.2%	21.22	0.09688	92.22	334.7%	0.42111	48.02	26.80	126.3%	0.21926
3	20%	438	3.0	357	85.5%	36.43	0.08318	101.62	178.9%	0.23201	70.54	34.10	93.6%	0.16104
4	30%	657	3.0	114	93.9%	58.35	0.08881	111.02	90.3%	0.16898	93.05	34.70	59.5%	0.14163
5	40%	876	3.0	39	96.8%	82.92	0.09466	120.42	45.2%	0.13746	115.57	32.65	39.4%	0.13193
6	50%	1,095	3.0	26	98.7%	107.49	0.09816	129.82	20.8%	0.11856	138.09	30.60	28.5%	0.12611
7	60%	1,314	3.0	14	99.7%	132.05	0.10050	139.22	5.4%	0.10595	160.61	28.55	21.6%	0.12223
8	70%	1,533	3.0	2	99.9%	156.62	0.10217	148.62	-5.1%	0.09694	183.12	26.50	16.9%	0.11945
9	80%	1,752	3.0	1	99.9%	181.19	0.10342	158.01	-12.8%	0.09019	205.64	24.45	13.5%	0.11737
10	90%	1,971	3.0	1	100.0%	205.75	0.10439	167.41	-18.6%	0.08494	228.16	22.40	10.9%	0.11576
11	100%	2,190	3.0	-	100.0%	230.32	0.10517	176.81	-23.2%	0.08074	250.68	20.35	8.8%	0.11446
Winter														
12	0%	-	-	-	0.0%	$6.00		$27.77	362.8%		$18.00	$12.00	200.0%	
13	10%	219	3.0	804	59.2%	21.22	0.09688	88.17	315.6%	0.40262	44.03	22.82	107.6%	0.20107
14	20%	438	3.0	357	85.5%	36.43	0.08318	97.04	166.4%	0.22155	62.57	26.14	71.7%	0.14285
15	30%	657	3.0	114	93.9%	55.53	0.08451	105.90	90.7%	0.16119	81.10	25.58	46.1%	0.12344
16	40%	876	3.0	39	96.8%	76.15	0.08693	114.76	50.7%	0.13101	99.64	23.49	30.8%	0.11374
17	50%	1,095	3.0	26	98.7%	96.78	0.08838	123.62	27.7%	0.11290	118.17	21.39	22.1%	0.10792
18	60%	1,314	3.0	14	99.7%	117.40	0.08935	132.48	12.8%	0.10083	136.70	19.30	16.4%	0.10404
19	70%	1,533	3.0	2	99.9%	138.03	0.09004	141.35	2.4%	0.09220	155.24	17.21	12.5%	0.10126
20	80%	1,752	3.0	1	99.9%	158.65	0.09055	150.21	-5.3%	0.08574	173.77	15.12	9.5%	0.09918
21	90%	1,971	3.0	1	100.0%	179.28	0.09096	159.07	-11.3%	0.08071	192.31	13.03	7.3%	0.09757
22	100%	2,190	3.0	-	100.0%	199.90	0.09128	167.93	-16.0%	0.07668	210.84	10.94	5.5%	0.09627

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Secondary Voltage (< 10 kW)

Unbundled Seasonal Demand Rate with $/kW Electric Delivery charge

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E) Number of Bills	(F) Cum. % of Bills	(G) Bill at E01C Rates	(H) Cents per kWh	(I) Bill at Cost of Service	(J) Percent Change	(K) Cents per kWh	(L) Bill at Proposed Rates	(M) Dollar Change	(N) Percent Change	(O) Cents per kWh
Summer														
1	0%	-	-	-	0.0%	$6.00		$27.77	362.8%		$18.00	$12.00	200.0%	
2	10%	657	9.0	804	59.2%	58.35	0.08881	221.13	279.0%	0.33657	108.05	49.70	85.2%	0.16446
3	20%	1,314	9.0	357	85.5%	132.05	0.10050	249.32	88.8%	0.18974	175.61	43.55	33.0%	0.13364
4	30%	1,971	9.0	114	93.9%	205.75	0.10439	277.52	34.9%	0.14080	243.16	37.40	18.2%	0.12337
5	40%	2,628	9.0	39	96.8%	279.46	0.10634	305.72	9.4%	0.11633	310.71	31.26	11.2%	0.11823
6	50%	3,285	9.0	26	98.7%	353.16	0.10751	333.91	-5.4%	0.10165	378.26	25.11	7.1%	0.11515
7	60%	3,942	9.0	14	99.7%	426.86	0.10828	362.11	-15.2%	0.09186	445.82	18.96	4.4%	0.11309
8	70%	4,599	9.0	2	99.9%	500.56	0.10884	390.31	-22.0%	0.08487	513.37	12.81	2.6%	0.11163
9	80%	5,256	9.0	1	99.9%	574.26	0.10926	418.50	-27.1%	0.07962	580.92	6.66	1.2%	0.11053
10	90%	5,913	9.0	1	100.0%	647.96	0.10958	446.70	-31.1%	0.07555	648.47	0.51	0.1%	0.10967
11	100%	6,570	9.0	-	100.0%	721.66	0.10984	474.89	-34.2%	0.07228	716.03	-5.64	-0.8%	0.10898
Winter														
12	0%	-	-	-	0.0%	$6.00		$27.77	362.8%		$18.00	$12.00	200.0%	
13	10%	657	9.0	804	59.2%	55.53	0.08451	208.98	276.4%	0.31809	96.10	40.58	73.1%	0.14627
14	20%	1,314	9.0	357	85.5%	117.40	0.08935	235.57	100.7%	0.17928	151.70	34.30	29.2%	0.11545
15	30%	1,971	9.0	114	93.9%	179.28	0.09096	262.16	46.2%	0.13301	207.31	28.03	15.6%	0.10518
16	40%	2,628	9.0	39	96.8%	241.15	0.09176	288.74	19.7%	0.10987	262.91	21.76	9.0%	0.10004
17	50%	3,285	9.0	26	98.7%	303.03	0.09225	315.33	4.1%	0.09599	318.51	15.48	5.1%	0.09696
18	60%	3,942	9.0	14	99.7%	364.90	0.09257	341.91	-6.3%	0.08674	374.11	9.21	2.5%	0.09490
19	70%	4,599	9.0	2	99.9%	426.78	0.09280	368.50	-13.7%	0.08013	429.71	2.94	0.7%	0.09344
20	80%	5,256	9.0	1	99.9%	488.65	0.09297	395.09	-19.1%	0.07517	485.32	-3.34	-0.7%	0.09234
21	90%	5,913	9.0	1	100.0%	550.53	0.09310	421.67	-23.4%	0.07131	540.92	-9.61	-1.7%	0.09148
22	100%	6,570	9.0	-	100.0%	612.40	0.09321	448.26	-26.8%	0.06823	596.52	-15.89	-2.6%	0.09079

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Secondary Voltage (≥ 10 kW < 50 kW)

Unbundled Seasonal Demand Rate

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E) Number of Bills	(F) Cum. % of Bills	(G) Bill at E06 Rates	(H) Cents per kWh	(I) Bill at Cost of Service	(J) Percent Change	(K) Cents per kWh	(L) Bill at Proposed Rates	(M) Dollar Change	(N) Percent Change	(O) Cents per kWh
Summer														
1	0%	-	25	85	0.1%	$350.75		$473.73	35.1%		$348.50	-$2.25	-0.6%	
2	10%	1,825	25	13,365	8.7%	445.61	0.24417	550.41	23.5%	0.30160	462.60	16.99	3.8%	0.25348
3	20%	3,650	25	28,036	26.7%	540.47	0.14807	627.10	16.0%	0.17181	576.70	36.23	6.7%	0.15800
4	30%	5,475	25	31,405	47.0%	635.33	0.11604	703.78	10.8%	0.12854	690.80	55.46	8.7%	0.12617
5	40%	7,300	25	28,990	65.6%	730.19	0.10003	780.47	6.9%	0.10691	804.90	74.70	10.2%	0.11026
6	50%	9,125	25	24,356	81.3%	825.06	0.09042	857.15	3.9%	0.09393	919.00	93.94	11.4%	0.10071
7	60%	10,950	25	16,065	91.7%	919.92	0.08401	933.84	1.5%	0.08528	1,033.09	113.18	12.3%	0.09435
8	70%	12,775	25	8,187	97.0%	1,014.78	0.07943	1,010.52	-0.4%	0.07910	1,147.19	132.41	13.0%	0.08980
9	80%	14,600	25	3,140	99.0%	1,109.64	0.07600	1,087.21	-2.0%	0.07447	1,261.29	151.65	13.7%	0.08639
10	90%	16,425	25	1,127	99.7%	1,204.50	0.07333	1,163.89	-3.4%	0.07086	1,375.39	170.89	14.2%	0.08374
11	100%	18,250	25	449	100.0%	1,299.36	0.07120	1,240.58	-4.5%	0.06798	1,489.49	190.13	14.6%	0.08162
Winter														
12	0%	-	25	85	0.1%	$316.25		$447.36	41.5%		$323.50	$7.25	2.3%	
13	10%	1,825	25	13,365	8.7%	411.11	0.22527	519.57	26.4%	0.28470	430.72	19.61	4.8%	0.23601
14	20%	3,650	25	28,036	26.7%	505.97	0.13862	591.79	17.0%	0.16213	537.94	31.97	6.3%	0.14738
15	30%	5,475	25	31,405	47.0%	600.83	0.10974	664.00	10.5%	0.12128	645.16	44.32	7.4%	0.11784
16	40%	7,300	25	28,990	65.6%	695.69	0.09530	736.21	5.8%	0.10085	752.38	56.68	8.1%	0.10307
17	50%	9,125	25	24,356	81.3%	790.56	0.08664	808.42	2.3%	0.08859	859.59	69.04	8.7%	0.09420
18	60%	10,950	25	16,065	91.7%	885.42	0.08086	880.63	-0.5%	0.08042	966.81	81.40	9.2%	0.08829
19	70%	12,775	25	8,187	97.0%	980.28	0.07673	952.85	-2.8%	0.07459	1,074.03	93.75	9.6%	0.08407
20	80%	14,600	25	3,140	99.0%	1,075.14	0.07364	1,025.06	-4.7%	0.07021	1,181.25	106.11	9.9%	0.08091
21	90%	16,425	25	1,127	99.7%	1,170.00	0.07123	1,097.27	-6.2%	0.06680	1,288.47	118.47	10.1%	0.07845
22	100%	18,250	25	449	100.0%	1,264.86	0.06931	1,169.48	-7.5%	0.06408	1,395.69	130.83	10.3%	0.07648

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Secondary Voltage (≥ 10 kW < 50 kW)

Unbundled Seasonal Demand Rate

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E) Number of Bills	(F) Cum. % of Bills	(G) Bill at E06 Rates	(H) Cents per kWh	(I) Bill at Cost of Service	(J) Percent Change	(K) Cents per kWh	(L) Bill at Proposed Rates	(M) Dollar Change	(N) Percent Change	(O) Cents per kWh
Summer														
1	0%	-	40	85	0.1%	$561.20		$739.67	31.8%		$542.60	-$18.60	-3.3%	
2	10%	2,920	40	13,365	8.7%	712.98	0.24417	862.36	21.0%	0.29533	725.16	12.18	1.7%	0.24834
3	20%	5,840	40	28,036	26.7%	864.76	0.14807	985.06	13.9%	0.16867	907.72	42.96	5.0%	0.15543
4	30%	8,760	40	31,405	47.0%	1,016.53	0.11604	1,107.76	9.0%	0.12646	1,090.28	73.74	7.3%	0.12446
5	40%	11,680	40	28,990	65.6%	1,168.31	0.10003	1,230.45	5.3%	0.10535	1,272.83	104.52	8.9%	0.10898
6	50%	14,600	40	24,356	81.3%	1,320.09	0.09042	1,353.15	2.5%	0.09268	1,455.39	135.30	10.2%	0.09968
7	60%	17,520	40	16,065	91.7%	1,471.87	0.08401	1,475.84	0.3%	0.08424	1,637.95	166.08	11.3%	0.09349
8	70%	20,440	40	8,187	97.0%	1,623.64	0.07943	1,598.54	-1.5%	0.07821	1,820.51	196.86	12.1%	0.08907
9	80%	23,360	40	3,140	99.0%	1,775.42	0.07600	1,721.24	-3.1%	0.07368	2,003.07	227.64	12.8%	0.08575
10	90%	26,280	40	1,127	99.7%	1,927.20	0.07333	1,843.93	-4.3%	0.07016	2,185.63	258.43	13.4%	0.08317
11	100%	29,200	40	449	100.0%	2,078.98	0.07120	1,966.63	-5.4%	0.06735	2,368.18	289.21	13.9%	0.08110
Winter														
12	0%	-	40	85	0.1%	$506.00		$697.48	37.8%		$502.60	-$3.40	-0.7%	
13	10%	2,920	40	13,365	8.7%	657.78	0.22527	813.02	23.6%	0.27843	674.15	16.37	2.5%	0.23087
14	20%	5,840	40	28,036	26.7%	809.56	0.13862	928.56	14.7%	0.15900	845.70	36.14	4.5%	0.14481
15	30%	8,760	40	31,405	47.0%	961.33	0.10974	1,044.10	8.6%	0.11919	1,017.25	55.92	5.8%	0.11612
16	40%	11,680	40	28,990	65.6%	1,113.11	0.09530	1,159.64	4.2%	0.09928	1,188.80	75.69	6.8%	0.10178
17	50%	14,600	40	24,356	81.3%	1,264.89	0.08664	1,275.18	0.8%	0.08734	1,360.35	95.46	7.5%	0.09317
18	60%	17,520	40	16,065	91.7%	1,416.67	0.08086	1,390.72	-1.8%	0.07938	1,531.90	115.23	8.1%	0.08744
19	70%	20,440	40	8,187	97.0%	1,568.44	0.07673	1,506.26	-4.0%	0.07369	1,703.45	135.01	8.6%	0.08334
20	80%	23,360	40	3,140	99.0%	1,720.22	0.07364	1,621.80	-5.7%	0.06943	1,875.00	154.78	9.0%	0.08027
21	90%	26,280	40	1,127	99.7%	1,872.00	0.07123	1,737.34	-7.2%	0.06611	2,046.55	174.55	9.3%	0.07787
22	100%	29,200	40	449	100.0%	2,023.78	0.06931	1,852.87	-8.4%	0.06345	2,218.10	194.32	9.6%	0.07596

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Secondary Voltage (≥ 10 kW < 50 kW)

Unbundled Seasonal Demand Rate

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E) Number of Bills	(F) Cum. % of Bills	(G) Bill at E01C Rates	(H) Cents per kWh	(I) Bill at Cost of Service	(J) Percent Change	(K) Cents per kWh	(L) Bill at FY 2012 Rates	(M) Dollar Change	(N) Percent Change	(O) Cents per kWh
Summer														
1	0%	-	15	-	0.0%	$6.00		$296.43	4840.6%		$121.60	$115.60	1926.7%	
2	10%	1,095	15	1,202	34.6%	107.49	0.09816	342.45	218.6%	0.31274	207.98	100.50	93.5%	0.18994
3	20%	2,190	15	1,369	74.1%	230.32	0.10517	388.46	68.7%	0.17738	294.37	64.05	27.8%	0.13442
4	30%	3,285	15	610	91.7%	353.16	0.10751	434.47	23.0%	0.13226	380.75	27.60	7.8%	0.11591
5	40%	4,380	15	222	98.1%	475.99	0.10867	480.48	0.9%	0.10970	467.14	-8.85	-1.9%	0.10665
6	50%	5,475	15	50	99.5%	598.83	0.10938	526.49	-12.1%	0.09616	553.52	-45.31	-7.6%	0.10110
7	60%	6,570	15	10	99.8%	721.66	0.10984	572.50	-20.7%	0.08714	639.91	-81.76	-11.3%	0.09740
8	70%	7,665	15	3	99.9%	844.50	0.11018	618.51	-26.8%	0.08069	726.29	-118.21	-14.0%	0.09475
9	80%	8,760	15	3	100.0%	967.34	0.11043	664.52	-31.3%	0.07586	812.68	-154.66	-16.0%	0.09277
10	90%	9,855	15	1	100.0%	1,090.17	0.11062	710.53	-34.8%	0.07210	899.06	-191.11	-17.5%	0.09123
11	100%	10,950	15	-	100.0%	1,213.01	0.11078	756.54	-37.6%	0.06909	985.45	-227.56	-18.8%	0.09000
Winter														
12	0%	-	15	-	0.0%	$6.00		$280.61	4576.9%		$121.60	$115.60	1926.7%	
13	10%	1,095	15	1,202	34.6%	96.78	0.08838	323.94	234.7%	0.29584	202.71	105.93	109.5%	0.18512
14	20%	2,190	15	1,369	74.1%	199.90	0.09128	367.27	83.7%	0.16770	283.81	83.91	42.0%	0.12960
15	30%	3,285	15	610	91.7%	303.03	0.09225	410.60	35.5%	0.12499	364.92	61.89	20.4%	0.11109
16	40%	4,380	15	222	98.1%	406.15	0.09273	453.92	11.8%	0.10364	446.03	39.87	9.8%	0.10183
17	50%	5,475	15	50	99.5%	509.28	0.09302	497.25	-2.4%	0.09082	527.13	17.85	3.5%	0.09628
18	60%	6,570	15	10	99.8%	612.40	0.09321	540.58	-11.7%	0.08228	608.24	-4.16	-0.7%	0.09258
19	70%	7,665	15	3	99.9%	715.53	0.09335	583.90	-18.4%	0.07618	689.35	-26.18	-3.7%	0.08993
20	80%	8,760	15	3	100.0%	818.66	0.09345	627.23	-23.4%	0.07160	770.45	-48.20	-5.9%	0.08795
21	90%	9,855	15	1	100.0%	921.78	0.09353	670.56	-27.3%	0.06804	851.56	-70.22	-7.6%	0.08641
22	100%	10,950	15	-	100.0%	1,024.91	0.09360	713.89	-30.3%	0.06520	932.67	-92.24	-9.0%	0.08518

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Secondary Voltage (≥ 10 kW < 50 kW)

Unbundled Seasonal Demand Rate

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E) Number of Bills	(F) Cum. % of Bills	(G) Bill at E01C Rates	(H) Cents per kWh	(I) Bill at Cost of Service	(J) Percent Change	(K) Cents per kWh	(L) Bill at FY 2012 Rates	(M) Dollar Change	(N) Percent Change	(O) Cents per kWh
Summer														
1	0%	-	40	-	0.0%	$6.00		$739.67	12227.8%		$282.60	$276.60	4610.0%	
2	10%	2,920	40	1,202	34.6%	312.21	0.10692	862.36	176.2%	0.29533	512.96	200.75	64.3%	0.17567
3	20%	5,840	40	1,369	74.1%	639.77	0.10955	985.06	54.0%	0.16867	743.32	103.54	16.2%	0.12728
4	30%	8,760	40	610	91.7%	967.34	0.11043	1,107.76	14.5%	0.12646	973.68	6.34	0.7%	0.11115
5	40%	11,680	40	222	98.1%	1,294.90	0.11086	1,230.45	-5.0%	0.10535	1,204.04	-90.86	-7.0%	0.10309
6	50%	14,600	40	50	99.5%	1,622.46	0.11113	1,353.15	-16.6%	0.09268	1,434.39	-188.07	-11.6%	0.09825
7	60%	17,520	40	10	99.8%	1,950.02	0.11130	1,475.84	-24.3%	0.08424	1,664.75	-285.27	-14.6%	0.09502
8	70%	20,440	40	3	99.9%	2,277.58	0.11143	1,598.54	-29.8%	0.07821	1,895.11	-382.47	-16.8%	0.09272
9	80%	23,360	40	3	100.0%	2,605.14	0.11152	1,721.24	-33.9%	0.07368	2,125.47	-479.67	-18.4%	0.09099
10	90%	26,280	40	1	100.0%	2,932.71	0.11159	1,843.93	-37.1%	0.07016	2,355.83	-576.88	-19.7%	0.08964
11	100%	29,200	40	-	100.0%	3,260.27	0.11165	1,966.63	-39.7%	0.06735	2,586.19	-674.08	-20.7%	0.08857
Winter														
12	0%	-	40	-	0.0%	$6.00		$697.48	11524.7%		$282.60	$276.60	4610.0%	
13	10%	2,920	40	1,202	34.6%	268.65	0.09200	813.02	202.6%	0.27843	498.88	230.23	85.7%	0.17085
14	20%	5,840	40	1,369	74.1%	543.65	0.09309	928.56	70.8%	0.15900	715.17	171.52	31.5%	0.12246
15	30%	8,760	40	610	91.7%	818.66	0.09345	1,044.10	27.5%	0.11919	931.45	112.80	13.8%	0.10633
16	40%	11,680	40	222	98.1%	1,093.66	0.09364	1,159.64	6.0%	0.09928	1,147.74	54.08	4.9%	0.09827
17	50%	14,600	40	50	99.5%	1,368.66	0.09374	1,275.18	-6.8%	0.08734	1,364.02	-4.64	-0.3%	0.09343
18	60%	17,520	40	10	99.8%	1,643.66	0.09382	1,390.72	-15.4%	0.07938	1,580.31	-63.35	-3.9%	0.09020
19	70%	20,440	40	3	99.9%	1,918.66	0.09387	1,506.26	-21.5%	0.07369	1,796.59	-122.07	-6.4%	0.08790
20	80%	23,360	40	3	100.0%	2,193.66	0.09391	1,621.80	-26.1%	0.06943	2,012.88	-180.79	-8.2%	0.08617
21	90%	26,280	40	1	100.0%	2,468.67	0.09394	1,737.34	-29.6%	0.06611	2,229.16	-239.51	-9.7%	0.08482
22	100%	29,200	40	-	100.0%	2,743.67	0.09396	1,852.87	-32.5%	0.06345	2,445.44	-298.22	-10.9%	0.08375

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Secondary Voltage (≥ 10 kW < 50 kW)

Unbundled Seasonal Demand Rate

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E) Number of Bills	(F) Cum. % of Bills	(G) Bill at E02 Rates	(H) Cents per kWh	(I) Bill at Cost of Service	(J) Percent Change	(K) Cents per kWh	(L) Bill at FY 2012 Rates	(M) Dollar Change	(N) Percent Change	(O) Cents per kWh
Summer														
1	0%	-	15	24	0.1%	$6.00		$296.43	4840.6%		$121.60	$115.60	1926.7%	
2	10%	1,095	15	3,331	14.1%	113.72	0.10386	342.45	201.1%	0.31274	207.98	94.26	82.9%	0.18994
3	20%	2,190	15	6,139	39.9%	221.45	0.10112	388.46	75.4%	0.17738	294.37	72.92	32.9%	0.13442
4	30%	3,285	15	5,483	62.9%	329.17	0.10021	434.47	32.0%	0.13226	380.75	51.58	15.7%	0.11591
5	40%	4,380	15	3,747	78.7%	436.90	0.09975	480.48	10.0%	0.10970	467.14	30.24	6.9%	0.10665
6	50%	5,475	15	2,512	89.3%	544.62	0.09947	526.49	-3.3%	0.09616	553.52	8.90	1.6%	0.10110
7	60%	6,570	15	1,436	95.3%	652.35	0.09929	572.50	-12.2%	0.08714	639.91	-12.44	-1.9%	0.09740
8	70%	7,665	15	635	98.0%	760.07	0.09916	618.51	-18.6%	0.08069	726.29	-33.78	-4.4%	0.09475
9	80%	8,760	15	278	99.1%	867.80	0.09906	664.52	-23.4%	0.07586	812.68	-55.12	-6.4%	0.09277
10	90%	9,855	15	143	99.7%	975.52	0.09899	710.53	-27.2%	0.07210	899.06	-76.46	-7.8%	0.09123
11	100%	10,950	15	66	100.0%	1,083.25	0.09893	756.54	-30.2%	0.06909	985.45	-97.80	-9.0%	0.09000
Winter														
12	0%	-	15	24	0.1%	$6.00		$280.61	4576.9%		$121.60	$115.60	1926.7%	
13	10%	1,095	15	3,331	14.1%	94.01	0.08586	323.94	244.6%	0.29584	202.71	108.69	115.6%	0.18512
14	20%	2,190	15	6,139	39.9%	182.03	0.08312	367.27	101.8%	0.16770	283.81	101.78	55.9%	0.12960
15	30%	3,285	15	5,483	62.9%	270.04	0.08221	410.60	52.0%	0.12499	364.92	94.88	35.1%	0.11109
16	40%	4,380	15	3,747	78.7%	358.06	0.08175	453.92	26.8%	0.10364	446.03	87.97	24.6%	0.10183
17	50%	5,475	15	2,512	89.3%	446.07	0.08147	497.25	11.5%	0.09082	527.13	81.06	18.2%	0.09628
18	60%	6,570	15	1,436	95.3%	534.09	0.08129	540.58	1.2%	0.08228	608.24	74.15	13.9%	0.09258
19	70%	7,665	15	635	98.0%	622.10	0.08116	583.90	-6.1%	0.07618	689.35	67.24	10.8%	0.08993
20	80%	8,760	15	278	99.1%	710.12	0.08106	627.23	-11.7%	0.07160	770.45	60.34	8.5%	0.08795
21	90%	9,855	15	143	99.7%	798.13	0.08099	670.56	-16.0%	0.06804	851.56	53.43	6.7%	0.08641
22	100%	10,950	15	66	100.0%	886.15	0.08093	713.89	-19.4%	0.06520	932.67	46.52	5.2%	0.08518

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Secondary Voltage (≥ 50 kW)

Unbundled Seasonal Demand Rate

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E) Number of Bills	(F) Cum. % of Bills	(G) Bill at E06 Rates	(H) Cents per kWh	(I) Bill at Cost of Service	(J) Percent Change	(K) Cents per kWh	(L) Bill at Proposed Rates	(M) Dollar Change	(N) Percent Change	(O) Cents per kWh
Summer														
1	0%	-	275	-	0.0%	$3,858.25		$5,191.30	34.6%		$4,209.25	$351.00	9.1%	
2	10%	20,075	275	2,273	4.6%	4,901.72	0.24417	6,027.71	23.0%	0.30026	5,311.57	409.85	8.4%	0.26459
3	20%	40,150	275	4,678	14.0%	5,945.20	0.14807	6,864.12	15.5%	0.17096	6,413.89	468.69	7.9%	0.15975
4	30%	60,225	275	6,253	26.5%	6,988.67	0.11604	7,700.52	10.2%	0.12786	7,516.20	527.54	7.5%	0.12480
5	40%	80,300	275	7,347	41.3%	8,032.14	0.10003	8,536.93	6.3%	0.10631	8,618.52	586.38	7.3%	0.10733
6	50%	100,375	275	9,852	61.1%	9,075.61	0.09042	9,373.33	3.3%	0.09338	9,720.84	645.23	7.1%	0.09685
7	60%	120,450	275	8,991	79.2%	10,119.09	0.08401	10,209.74	0.9%	0.08476	10,823.16	704.07	7.0%	0.08986
8	70%	140,525	275	5,709	90.6%	11,162.56	0.07943	11,046.14	-1.0%	0.07861	11,925.48	762.92	6.8%	0.08486
9	80%	160,600	275	2,948	96.6%	12,206.03	0.07600	11,882.55	-2.7%	0.07399	13,027.80	821.77	6.7%	0.08112
10	90%	180,675	275	1,214	99.0%	13,249.50	0.07333	12,718.96	-4.0%	0.07040	14,130.11	880.61	6.6%	0.07821
11	100%	200,750	275	495	100.0%	14,292.98	0.07120	13,555.36	-5.2%	0.06752	15,232.43	939.46	6.6%	0.07588
Winter														
12	0%	-	275	-	0.0%	$3,478.75		$4,877.52	40.2%		$3,934.25	$455.50	13.1%	
13	10%	20,075	275	2,273	4.6%	4,522.22	0.22527	5,664.72	25.3%	0.28218	4,970.32	448.10	9.9%	0.24759
14	20%	40,150	275	4,678	14.0%	5,565.70	0.13862	6,451.92	15.9%	0.16070	6,006.39	440.70	7.9%	0.14960
15	30%	60,225	275	6,253	26.5%	6,609.17	0.10974	7,239.13	9.5%	0.12020	7,042.46	433.29	6.6%	0.11694
16	40%	80,300	275	7,347	41.3%	7,652.64	0.09530	8,026.33	4.9%	0.09995	8,078.53	425.89	5.6%	0.10060
17	50%	100,375	275	9,852	61.1%	8,696.11	0.08664	8,813.53	1.4%	0.08781	9,114.60	418.49	4.8%	0.09081
18	60%	120,450	275	8,991	79.2%	9,739.59	0.08086	9,600.73	-1.4%	0.07971	10,150.67	411.09	4.2%	0.08427
19	70%	140,525	275	5,709	90.6%	10,783.06	0.07673	10,387.94	-3.7%	0.07392	11,186.75	403.69	3.7%	0.07961
20	80%	160,600	275	2,948	96.6%	11,826.53	0.07364	11,175.14	-5.5%	0.06958	12,222.82	396.29	3.4%	0.07611
21	90%	180,675	275	1,214	99.0%	12,870.00	0.07123	11,962.34	-7.1%	0.06621	13,258.89	388.88	3.0%	0.07339
22	100%	200,750	275	495	100.0%	13,913.48	0.06931	12,749.54	-8.4%	0.06351	14,294.96	381.48	2.7%	0.07121

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Secondary Voltage (≥ 50 kW)

Unbundled Seasonal Demand Rate

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E) Number of Bills	(F) Cum. % of Bills	(G) Bill at E01C Rates	(H) Cents per kWh	(I) Bill at Cost of Service	(J) Percent Change	(K) Cents per kWh	(L) Bill at FY 2012 Rates	(M) Dollar Change	(N) Percent Change	(O) Cents per kWh
Summer														
1	0%	-	75	-	0.0%	$6.00		$1,465.84	24330.6%		$557.75	$551.75	9195.8%	
2	10%	5,475	75	212	13.0%	598.83	0.10938	1,693.95	182.9%	0.30940	1,006.92	408.09	68.1%	0.18391
3	20%	10,950	75	670	54.2%	1,213.01	0.11078	1,922.06	58.5%	0.17553	1,456.09	243.08	20.0%	0.13298
4	30%	16,425	75	471	83.1%	1,827.19	0.11124	2,150.17	17.7%	0.13091	1,905.26	78.07	4.3%	0.11600
5	40%	21,900	75	179	94.1%	2,441.36	0.11148	2,378.28	-2.6%	0.10860	2,354.43	-86.94	-3.6%	0.10751
6	50%	27,375	75	71	98.5%	3,055.54	0.11162	2,606.39	-14.7%	0.09521	2,803.60	-251.95	-8.2%	0.10241
7	60%	32,850	75	15	99.4%	3,669.72	0.11171	2,834.50	-22.8%	0.08629	3,252.76	-416.96	-11.4%	0.09902
8	70%	38,325	75	5	99.7%	4,283.90	0.11178	3,062.61	-28.5%	0.07991	3,701.93	-581.97	-13.6%	0.09659
9	80%	43,800	75	3	99.9%	4,898.08	0.11183	3,290.72	-32.8%	0.07513	4,151.10	-746.98	-15.3%	0.09477
10	90%	49,275	75	1	99.9%	5,512.26	0.11187	3,518.83	-36.2%	0.07141	4,600.27	-911.98	-16.5%	0.09336
11	100%	54,750	75	1	100.0%	6,126.43	0.11190	3,746.94	-38.8%	0.06844	5,049.44	-1,076.99	-17.6%	0.09223
Winter														
12	0%	-	75	-	0.0%	$6.00		$1,380.26	22904.3%		$557.75	$551.75	9195.8%	
13	10%	5,475	75	212	13.0%	598.83	0.10938	1,594.95	166.3%	0.29132	979.33	380.50	63.5%	0.17887
14	20%	10,950	75	670	54.2%	1,213.01	0.11078	1,809.64	49.2%	0.16526	1,400.90	187.89	15.5%	0.12794
15	30%	16,425	75	471	83.1%	1,827.19	0.11124	2,024.33	10.8%	0.12325	1,822.48	-4.71	-0.3%	0.11096
16	40%	21,900	75	179	94.1%	2,441.36	0.11148	2,239.03	-8.3%	0.10224	2,244.05	-197.31	-8.1%	0.10247
17	50%	27,375	75	71	98.5%	3,055.54	0.11162	2,453.72	-19.7%	0.08963	2,665.63	-389.92	-12.8%	0.09737
18	60%	32,850	75	15	99.4%	3,669.72	0.11171	2,668.41	-27.3%	0.08123	3,087.20	-582.52	-15.9%	0.09398
19	70%	38,325	75	5	99.7%	4,283.90	0.11178	2,883.10	-32.7%	0.07523	3,508.78	-775.12	-18.1%	0.09155
20	80%	43,800	75	3	99.9%	4,898.08	0.11183	3,097.79	-36.8%	0.07073	3,930.35	-967.73	-19.8%	0.08973
21	90%	49,275	75	1	99.9%	5,512.26	0.11187	3,312.48	-39.9%	0.06722	4,351.93	-1,160.33	-21.1%	0.08832
22	100%	54,750	75	1	100.0%	6,126.43	0.11190	3,527.18	-42.4%	0.06442	4,773.50	-1,352.93	-22.1%	0.08719

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Secondary Voltage (≥ 50 kW)

Unbundled Seasonal Demand Rate

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E) Number of Bills	(F) Cum. % of Bills	(G) Bill at E01C Rates	(H) Cents per kWh	(I) Bill at Cost of Service	(J) Percent Change	(K) Cents per kWh	(L) Bill at FY 2012 Rates	(M) Dollar Change	(N) Percent Change	(O) Cents per kWh
Summer														
1	0%	-	275	-	0.0%	$6.00		$5,191.30	86421.7%		$1,871.75	$1,865.75	31095.8%	
2	10%	20,075	275	212	13.0%	2,236.64	0.11141	6,027.71	169.5%	0.30026	3,518.70	1,282.07	57.3%	0.17528
3	20%	40,150	275	670	54.2%	4,488.63	0.11180	6,864.12	52.9%	0.17096	5,165.66	677.03	15.1%	0.12866
4	30%	60,225	275	471	83.1%	6,740.61	0.11192	7,700.52	14.2%	0.12786	6,812.61	72.00	1.1%	0.11312
5	40%	80,300	275	179	94.1%	8,992.60	0.11199	8,536.93	-5.1%	0.10631	8,459.56	-533.04	-5.9%	0.10535
6	50%	100,375	275	71	98.5%	11,244.59	0.11203	9,373.33	-16.6%	0.09338	10,106.52	-1,138.07	-10.1%	0.10069
7	60%	120,450	275	15	99.4%	13,496.58	0.11205	10,209.74	-24.4%	0.08476	11,753.47	-1,743.11	-12.9%	0.09758
8	70%	140,525	275	5	99.7%	15,748.56	0.11207	11,046.14	-29.9%	0.07861	13,400.42	-2,348.14	-14.9%	0.09536
9	80%	160,600	275	3	99.9%	18,000.55	0.11208	11,882.55	-34.0%	0.07399	15,047.37	-2,953.18	-16.4%	0.09369
10	90%	180,675	275	1	99.9%	20,252.54	0.11209	12,718.96	-37.2%	0.07040	16,694.33	-3,558.21	-17.6%	0.09240
11	100%	200,750	275	1	100.0%	22,504.53	0.11210	13,555.36	-39.8%	0.06752	18,341.28	-4,163.25	-18.5%	0.09136
Winter														
12	0%	-	275	-	0.0%	$6.00		$4,877.52	81192.0%		$1,871.75	$1,865.75	31095.8%	
13	10%	20,075	275	212	13.0%	2,236.64	0.11141	5,664.72	153.3%	0.28218	3,417.53	1,180.89	52.8%	0.17024
14	20%	40,150	275	670	54.2%	4,488.63	0.11180	6,451.92	43.7%	0.16070	4,963.30	474.67	10.6%	0.12362
15	30%	60,225	275	471	83.1%	6,740.61	0.11192	7,239.13	7.4%	0.12020	6,509.08	-231.54	-3.4%	0.10808
16	40%	80,300	275	179	94.1%	8,992.60	0.11199	8,026.33	-10.7%	0.09995	8,054.85	-937.75	-10.4%	0.10031
17	50%	100,375	275	71	98.5%	11,244.59	0.11203	8,813.53	-21.6%	0.08781	9,600.63	-1,643.96	-14.6%	0.09565
18	60%	120,450	275	15	99.4%	13,496.58	0.11205	9,600.73	-28.9%	0.07971	11,146.40	-2,350.18	-17.4%	0.09254
19	70%	140,525	275	5	99.7%	15,748.56	0.11207	10,387.94	-34.0%	0.07392	12,692.18	-3,056.39	-19.4%	0.09032
20	80%	160,600	275	3	99.9%	18,000.55	0.11208	11,175.14	-37.9%	0.06958	14,237.95	-3,762.60	-20.9%	0.08865
21	90%	180,675	275	1	99.9%	20,252.54	0.11209	11,962.34	-40.9%	0.06621	15,783.73	-4,468.81	-22.1%	0.08736
22	100%	200,750	275	1	100.0%	22,504.53	0.11210	12,749.54	-43.3%	0.06351	17,329.50	-5,175.03	-23.0%	0.08632

Appendix H: Proposed Primary Voltage and Transmission Voltage Commercial and Industrial Customer Billing Impacts

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Primary Voltage (< 3 MW)

Unbundled Seasonal Demand Rate

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E) Number of Bills	(F) Cum. % of Bills	(G) Bill at Current Rates	(H) Cents per kWh	(I) Bill at Cost of Service	(J) Percent Change	(K) Cents per kWh	(L) Bill at Proposed Rates	(M) Dollar Change	(N) Percent Change	(O) Cents per kWh
Summer														
1	0%	-	820	12	2.1%	$9,922.00		$12,496.13	25.9%		$12,369.60	$2,447.60	24.7%	
2	10%	59,860	820	22	6.0%	12,813.77	0.21406	14,912.16	16.4%	0.24912	15,022.60	2,208.82	17.2%	0.25096
3	20%	119,720	820	9	7.6%	15,705.54	0.13119	17,328.20	10.3%	0.14474	17,675.59	1,970.05	12.5%	0.14764
4	30%	179,580	820	7	8.8%	18,597.31	0.10356	19,744.24	6.2%	0.10995	20,328.59	1,731.27	9.3%	0.11320
5	40%	239,440	820	40	15.8%	21,489.08	0.08975	22,160.28	3.1%	0.09255	22,981.58	1,492.50	6.9%	0.09598
6	50%	299,300	820	78	29.5%	24,380.85	0.08146	24,576.32	0.8%	0.08211	25,634.58	1,253.72	5.1%	0.08565
7	60%	359,160	820	100	47.1%	27,272.62	0.07593	26,992.35	-1.0%	0.07515	28,287.57	1,014.95	3.7%	0.07876
8	70%	419,020	820	118	67.8%	30,164.39	0.07199	29,408.39	-2.5%	0.07018	30,940.57	776.17	2.6%	0.07384
9	80%	478,880	820	104	86.1%	33,056.17	0.06903	31,824.43	-3.7%	0.06646	33,593.56	537.40	1.6%	0.07015
10	90%	538,740	820	65	97.5%	35,947.94	0.06673	34,240.47	-4.7%	0.06356	36,246.56	298.62	0.8%	0.06728
11	100%	598,600	820	14	100.0%	38,839.71	0.06488	36,656.51	-5.6%	0.06124	38,899.55	59.84	0.2%	0.06498
Winter														
12	0%	-	820	12	2.1%	$9,110.20		$11,687.66	28.3%		$11,549.60	$2,439.40	26.8%	
13	10%	59,860	820	22	6.0%	12,001.97	0.20050	13,960.31	16.3%	0.23322	14,043.97	2,042.00	17.0%	0.23461
14	20%	119,720	820	9	7.6%	14,893.74	0.12440	16,232.96	9.0%	0.13559	16,538.33	1,644.59	11.0%	0.13814
15	30%	179,580	820	7	8.8%	17,785.51	0.09904	18,505.61	4.0%	0.10305	19,032.70	1,247.19	7.0%	0.10598
16	40%	239,440	820	40	15.8%	20,677.28	0.08636	20,778.25	0.5%	0.08678	21,527.06	849.78	4.1%	0.08991
17	50%	299,300	820	78	29.5%	23,569.05	0.07875	23,050.90	-2.2%	0.07702	24,021.43	452.38	1.9%	0.08026
18	60%	359,160	820	100	47.1%	26,460.82	0.07367	25,323.55	-4.3%	0.07051	26,515.80	54.97	0.2%	0.07383
19	70%	419,020	820	118	67.8%	29,352.59	0.07005	27,596.19	-6.0%	0.06586	29,010.16	-342.43	-1.2%	0.06923
20	80%	478,880	820	104	86.1%	32,244.37	0.06733	29,868.84	-7.4%	0.06237	31,504.53	-739.84	-2.3%	0.06579
21	90%	538,740	820	65	97.5%	35,136.14	0.06522	32,141.49	-8.5%	0.05966	33,998.90	-1,137.24	-3.2%	0.06311
22	100%	598,600	820	14	100.0%	38,027.91	0.06353	34,414.13	-9.5%	0.05749	36,493.26	-1,534.65	-4.0%	0.06096

Austin Energy
2011 Electric System Rate Study

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Primary Voltage (≥ 3 MW < 20 MW)

Unbundled Seasonal Demand Rate

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E) Number of Bills	(F) Cum. % of Bills	(G) Bill at Current Rates	(H) Cents per kWh	(I) Bill at Cost of Service	(J) Percent Change	(K) Cents per kWh	(L) Bill at Proposed Rates	(M) Dollar Change	(N) Percent Change	(O) Cents per kWh
Summer														
1	0%	-	4,500	-	0.0%	$56,700.00		$88,579.29	56.2%		$89,435.00	$32,735.00	57.7%	
2	10%	328,500	4,500	-	0.0%	72,536.62	0.22081	101,786.06	40.3%	0.30985	103,537.51	31,000.88	42.7%	0.31518
3	20%	657,000	4,500	-	0.0%	88,373.25	0.13451	114,992.83	30.1%	0.17503	117,640.01	29,266.76	33.1%	0.17906
4	30%	985,500	4,500	-	0.0%	104,209.87	0.10574	128,199.61	23.0%	0.13009	131,742.52	27,532.64	26.4%	0.13368
5	40%	1,314,000	4,500	-	0.0%	120,046.49	0.09136	141,406.38	17.8%	0.10762	145,845.02	25,798.53	21.5%	0.11099
6	50%	1,642,500	4,500	1	0.5%	135,883.12	0.08273	154,613.15	13.8%	0.09413	159,947.53	24,064.41	17.7%	0.09738
7	60%	1,971,000	4,500	2	1.5%	151,719.74	0.07698	167,819.92	10.6%	0.08514	174,050.03	22,330.29	14.7%	0.08831
8	70%	2,299,500	4,500	28	15.8%	167,556.36	0.07287	181,026.69	8.0%	0.07872	188,152.54	20,596.17	12.3%	0.08182
9	80%	2,628,000	4,500	44	38.3%	183,392.99	0.06978	194,233.46	5.9%	0.07391	202,255.04	18,862.05	10.3%	0.07696
10	90%	2,956,500	4,500	66	71.9%	199,229.61	0.06739	207,440.24	4.1%	0.07016	216,357.55	17,127.93	8.6%	0.07318
11	100%	3,285,000	4,500	55	100.0%	215,066.23	0.06547	220,647.01	2.6%	0.06717	230,460.05	15,393.82	7.2%	0.07016
Winter														
12	0%	-	4,500	-	0.0%	$53,145.00		$82,575.67	55.4%		$84,935.00	$31,790.00	59.8%	
13	10%	328,500	4,500	-	0.0%	68,981.62	0.20999	94,995.54	37.7%	0.28918	98,193.26	29,211.64	42.3%	0.29891
14	20%	657,000	4,500	-	0.0%	84,818.25	0.12910	107,415.41	26.6%	0.16349	111,451.52	26,633.27	31.4%	0.16964
15	30%	985,500	4,500	-	0.0%	100,654.87	0.10214	119,835.28	19.1%	0.12160	124,709.78	24,054.91	23.9%	0.12654
16	40%	1,314,000	4,500	-	0.0%	116,491.49	0.08865	132,255.15	13.5%	0.10065	137,968.04	21,476.55	18.4%	0.10500
17	50%	1,642,500	4,500	1	0.5%	132,328.12	0.08057	144,675.02	9.3%	0.08808	151,226.30	18,898.18	14.3%	0.09207
18	60%	1,971,000	4,500	2	1.5%	148,164.74	0.07517	157,094.89	6.0%	0.07970	164,484.56	16,319.82	11.0%	0.08345
19	70%	2,299,500	4,500	28	15.8%	164,001.36	0.07132	169,514.76	3.4%	0.07372	177,742.82	13,741.46	8.4%	0.07730
20	80%	2,628,000	4,500	44	38.3%	179,837.99	0.06843	181,934.63	1.2%	0.06923	191,001.08	11,163.09	6.2%	0.07268
21	90%	2,956,500	4,500	66	71.9%	195,674.61	0.06618	194,354.50	-0.7%	0.06574	204,259.34	8,584.73	4.4%	0.06909
22	100%	3,285,000	4,500	55	100.0%	211,511.23	0.06439	206,774.37	-2.2%	0.06295	217,517.60	6,006.37	2.8%	0.06622

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Primary Voltage (≥ 20 MW)

Unbundled Seasonal Demand Rate

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E)	(F) Bill at Current Rates	(G) Cents per kWh	(H) Bill at Cost of Service	(I) Percent Change	(J) Cents per kWh	(K) Bill at Proposed Rates	(L) Dollar Change	(M) Percent Change	(N) Cents per kWh
Summer													
1	0%	-	30,000		$366,900		$569,365	55.2%		$585,100	$218,200	59.5%	
2	10%	2,190,000	30,000		462,710	0.21128	657,228	42.0%	0.30010	677,628	214,917	46.4%	0.30942
3	20%	4,380,000	30,000		558,520	0.12752	745,092	33.4%	0.17011	770,155	211,635	37.9%	0.17583
4	30%	6,570,000	30,000		654,330	0.09959	832,955	27.3%	0.12678	862,683	208,352	31.8%	0.13131
5	40%	8,760,000	30,000		750,140	0.08563	920,818	22.8%	0.10512	955,210	205,070	27.3%	0.10904
6	50%	10,950,000	30,000		845,950	0.07726	1,008,681	19.2%	0.09212	1,047,738	201,787	23.9%	0.09568
7	60%	13,140,000	30,000		941,761	0.07167	1,096,545	16.4%	0.08345	1,140,265	198,504	21.1%	0.08678
8	70%	15,330,000	30,000		1,037,571	0.06768	1,184,408	14.2%	0.07726	1,232,793	195,222	18.8%	0.08042
9	80%	17,520,000	30,000		1,133,381	0.06469	1,272,271	12.3%	0.07262	1,325,320	191,939	16.9%	0.07565
10	90%	19,710,000	30,000		1,229,191	0.06236	1,360,135	10.7%	0.06901	1,417,848	188,657	15.3%	0.07194
11	100%	21,900,000	30,000		1,325,001	0.06050	1,447,998	9.3%	0.06612	1,510,375	185,374	14.0%	0.06897
Winter													
12	0%	-	30,000		$333,600		$529,619	58.8%		$555,100	$221,500	66.4%	
13	10%	2,190,000	30,000		422,623	0.19298	612,237	44.9%	0.27956	642,087	219,464	51.9%	0.29319
14	20%	4,380,000	30,000		511,647	0.11681	694,854	35.8%	0.15864	729,074	217,427	42.5%	0.16646
15	30%	6,570,000	30,000		600,670	0.09143	777,471	29.4%	0.11834	816,060	215,391	35.9%	0.12421
16	40%	8,760,000	30,000		689,693	0.07873	860,089	24.7%	0.09818	903,047	213,354	30.9%	0.10309
17	50%	10,950,000	30,000		778,716	0.07112	942,706	21.1%	0.08609	990,034	211,318	27.1%	0.09041
18	60%	13,140,000	30,000		867,740	0.06604	1,025,323	18.2%	0.07803	1,077,021	209,281	24.1%	0.08197
19	70%	15,330,000	30,000		956,763	0.06241	1,107,940	15.8%	0.07227	1,164,008	207,245	21.7%	0.07593
20	80%	17,520,000	30,000		1,045,786	0.05969	1,190,558	13.8%	0.06795	1,250,994	205,208	19.6%	0.07140
21	90%	19,710,000	30,000		1,134,810	0.05758	1,273,175	12.2%	0.06460	1,337,981	203,172	17.9%	0.06788
22	100%	21,900,000	30,000		1,223,833	0.05588	1,355,792	10.8%	0.06191	1,424,968	201,135	16.4%	0.06507

Rate Adjustment Impact Assessment

Estimated Monthly Bills

Transmission Voltage

Unbundled Seasonal Demand Rate

(A) Line No.	(B) Monthly Load Factor	(C) Monthly Energy Usage	(D) Monthly Billed Demand	(E)	(F) Bill at Current Rates	(G) Cents per kWh	(H) Bill at Cost of Service	(I) Percent Change	(J) Cents per kWh	(K) Bill at Proposed Rates	(L) Dollar Change	(M) Percent Change	(N) Cents per kWh
Summer													
1	0%	-	10,000		$122,300.00		$128,605.93	5.2%		$157,400.00	$35,100.00	28.7%	
2	10%	730,000	10,000		153,796.31	0.21068	157,367.55	2.3%	0.21557	184,577.90	30,781.59	20.0%	0.25285
3	20%	1,460,000	10,000		185,292.61	0.12691	186,129.16	0.5%	0.12749	211,755.80	26,463.19	14.3%	0.14504
4	30%	2,190,000	10,000		216,788.92	0.09899	214,890.78	-0.9%	0.09812	238,933.70	22,144.78	10.2%	0.10910
5	40%	2,920,000	10,000		248,285.23	0.08503	243,652.39	-1.9%	0.08344	266,111.60	17,826.37	7.2%	0.09113
6	50%	3,650,000	10,000		279,781.54	0.07665	272,414.01	-2.6%	0.07463	293,289.50	13,507.96	4.8%	0.08035
7	60%	4,380,000	10,000		311,277.84	0.07107	301,175.62	-3.2%	0.06876	320,467.40	9,189.56	3.0%	0.07317
8	70%	5,110,000	10,000		342,774.15	0.06708	329,937.24	-3.7%	0.06457	347,645.30	4,871.15	1.4%	0.06803
9	80%	5,840,000	10,000		374,270.46	0.06409	358,698.85	-4.2%	0.06142	374,823.20	552.74	0.1%	0.06418
10	90%	6,570,000	10,000		405,766.77	0.06176	387,460.46	-4.5%	0.05897	402,001.10	-3,765.67	-0.9%	0.06119
11	100%	7,300,000	10,000		437,263.07	0.05990	416,222.08	-4.8%	0.05702	429,179.00	-8,084.07	-1.8%	0.05879
Winter													
12	0%	-	10,000		$111,200.00		$117,808.41	5.9%		$147,400.00	$36,200.00	32.6%	
13	10%	730,000	10,000		140,709.25	0.19275	144,843.64	2.9%	0.19842	172,950.00	32,240.75	22.9%	0.23692
14	20%	1,460,000	10,000		170,218.49	0.11659	171,878.87	1.0%	0.11773	198,500.00	28,281.51	16.6%	0.13596
15	30%	2,190,000	10,000		199,727.74	0.09120	198,914.10	-0.4%	0.09083	224,050.00	24,322.26	12.2%	0.10231
16	40%	2,920,000	10,000		229,236.99	0.07851	225,949.33	-1.4%	0.07738	249,600.00	20,363.01	8.9%	0.08548
17	50%	3,650,000	10,000		258,746.24	0.07089	252,984.56	-2.2%	0.06931	275,150.00	16,403.76	6.3%	0.07538
18	60%	4,380,000	10,000		288,255.48	0.06581	280,019.79	-2.9%	0.06393	300,700.00	12,444.52	4.3%	0.06865
19	70%	5,110,000	10,000		317,764.73	0.06218	307,055.02	-3.4%	0.06009	326,250.00	8,485.27	2.7%	0.06385
20	80%	5,840,000	10,000		347,273.98	0.05946	334,090.25	-3.8%	0.05721	351,800.00	4,526.02	1.3%	0.06024
21	90%	6,570,000	10,000		376,783.23	0.05735	361,125.48	-4.2%	0.05497	377,350.00	566.77	0.2%	0.05744
22	100%	7,300,000	10,000		406,292.47	0.05566	388,160.71	-4.5%	0.05317	402,900.00	-3,392.47	-0.8%	0.05519