BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR APPROVAL OF A GENERAL CHANGE IN	)	DOCKET NO. 10-067-U
RATES AND TARIFFS	)	

Direct Testimony

of

Gregory W. Tillman

on behalf of

Oklahoma Gas and Electric Company

September 28, 2010

Gregory W. Tillman

Direct Testimony

Qualifications, Experience and Purpose

Q. **Would you please state your name, business address and job responsibilities.**

A. My name is Gregory W. Tillman. My business address is 321 North Harvey, Oklahoma City, Oklahoma 73102. I am currently the Manager of Pricing for Oklahoma Gas and Electric Company ("OG&E" or "Company"). I am responsible for rate design, tariffs and analysis of pricing products.

Q. **Would you please summarize your education and professional background?**

A. I graduated from the University of Tulsa with a Bachelor of Science degree in Electrical Engineering in 1987. After serving on active duty as a Signal Officer in the United States Army, I joined Public Service Company of Oklahoma ("PSO") where I was employed in various positions in the Information Services, Business Planning, Rates and Regulatory, and Ventures departments from 1990 through 1997. Within the Rates and Regulatory department I served as the Supervisor of Power Billing and Data Collection. In this position I managed the billing for large industrial and commercial customers and led the implementation of the company's real-time pricing program. I also managed the implementation of real-time pricing for three other utilities within the Central and South West Corporation – Southwestern Electric Power Company ("SWEPCO"), Central Power and Light ("CPL") and West Texas Utilities ("WTU"). Following my employment at PSO, I joined the Retail department of the Williams Energy Company as the manager of systems for the retail gas and electric data and billing systems in 1997. During this time I also managed the customer billing function at Thermogas and accounting (billing) support functions at Williams Communications. In 2000, I joined Automated Energy where I served as the Vice President of Energy Solutions for two years. Following several assignments as a consultant and project manager in various industries, I joined OG&E in 2008 as a senior pricing analyst and was promoted to my current position as Manager of Pricing in January 2010.

Q. **Have you previously filed testimony before the Arkansas Public Service Commission (the "Commission" or "APSC")?**

A. No, I have not.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to introduce several new optional tariffs focused on attaining the goals of revenue recovery, efficiency and customer desires discussed by OG&E witness Bryan J. Scott. These new rates include a variable peak pricing tariff, a residential and commercial flat billing option and a load reduction rider which applies to Power and Light ("PL") and Power and Light-Time of Use ("PL-TOU") customers. I also discuss the Company's proposed modifications to the Day Ahead Pricing ("DAP") pilot program and request that it be accepted by the Commission as a permanent tariff. My testimony sponsors OG&E's Proof of Revenue (Schedule H), rate design for existing tariffs, and the proposed tariffs. Finally, I request approval of the tariffs for the Energy Cost Recovery ("ECR") and the proposed SPP Cost Recovery ("SPPCR") riders discussed by Company witness Donald Rowlett, the Storm Damage Recovery ("SDR") rider discussed by Company witness Sheri Richard, and the Customer Education and Demand Response ("CEDR") rider discussed by Mr. Scott.

New Proposed Tariffs

Q. **Please describe the new tariffs proposed for customers.**

A. OG&E proposes to offer two new dynamic time-of-use ("TOU") tariffs—a Residential and Commercial Variable Peak Pricing ("R-VPP" and "GS-VPP"), Flat Bill ("FB") products to its Residential and Commercial customers, a Load Reduction rider to PL and PL-TOU customers, and to make its pilot DAP tariff a permanent tariff.

Q. **Why is OG&E seeking approval from the Commission for these proposed programs?**

A. OG&E is proposing these tariffs to establish the foundation of pricing programs that will strengthen our portfolio of products and establish additional choices focused on our objectives as described in testimony of Mr. Scott. The proposed variable peak pricing programs hold substantial promise for providing OG&E with price responsive loads that

will contribute to more efficient utilization of resources. These programs are designed to motivate subscribers to target conservation during times of increased resource constraints. Customers who respond to these prices will not only earn the benefit of reduced overall billing, they also will generate benefits that will be passed on to all customers.

The FB product offering is designed to fulfill the desire of many customers to have access to a constant billing amount over an annual contract period.

The load reduction program creates a billing credit for larger customers in exchange for their commitment to reduce loads during periods when resources are limited—this will free up the energy required to serve our remaining customers.

A permanent DAP program will offer to our larger customers the opportunity to access our best pricing during all periods and the opportunity to reduce costs by decreasing load during times of system constraint reflected in higher prices.

Variable Peak Pricing (R-VPP and GS-VPP)

Q. **What is Variable Peak Pricing?**

A. VPP is a form of TOU pricing in which the price for the on-peak period varies each day based on the day-ahead expected system conditions. Variable peak pricing is intended to combine the effectiveness of a day-ahead pricing program with the simplicity of a fixed TOU price schedule. OG&E currently offers VPP in Oklahoma as a pilot program. OG&E proposes two tariffs for VPP – a Residential VPP tariff applicable to residential customers and a General Service VPP tariff, applicable to General Service, Municipal Pumping ("PM") and Athletic Field Lighting ("AFL") customers.

Q. **Please explain how the VPP tariffs are designed.**

A. The VPP tariffs are designed using the existing Residential and General Service TOU rates as their respective bases. The peak period price in the TOU rate is replaced with a variable price signal posted on the OG&E website for participating customers. A single price will apply to the entire five-hour window each day. There are four defined price levels (Low, Standard, High and Critical) to simplify communications of the price level. The prices assigned to each price level are based on the underlying Standard and TOU tariffs. The low price level equates to the off-peak energy prices; the standard price level

equates to the standard tariff summer season tail-block price; the high price level reflects the peak period energy price; and the critical price level is intended to produce the maximum response from our customers. The price levels are shown in Chart 1.

Chart 1. R-VPP and GS-VPP price levels.

Price Level	*R-VPP Price*	*GS-VPP Price*
Low	1.7¢ per kWh	1.7¢ per kWh
Standard	7.4¢ per kWh	5.4¢ per kWh
High	18.5¢ per kWh	18.5¢ per kWh
Critical	37.0¢ per kWh	37.0¢ per kWh

Q. **How is the price level selected for the peak period?**

A. The average of the DAP hourly prices for the peak period (2pm-7pm) will be used to select the VPP price level.

Q. **Are there other components of the VPP tariff?**

A. Yes, there is a best bill provision and an additional facilities charge. The best bill provision provides additional security to customers choosing the VPP rate. After the initial year, a comparison of total charges under the VPP rate and original rate will be made and a credit will be issued to the customer for any amount paid that exceeds what would have been paid under the customer's previous rate. A customer who continues on VPP for successive years will no longer receive best bill treatment.

The additional facilities charge is a nominal monthly rate of $2.00 for R-VPP and $3.50 for GS-VPP and covers the additional metering and administrative support costs.

Q. **How do customers benefit from the VPP rates?**

A. Customers who respond to the prices by reducing usage during higher priced hours will experience lower bills. Time-differentiated pricing allows customers to lower their current electric bills and supports investment decisions in conservation and efficiency that will pay increasing dividends in the future through avoided capacity costs. Subscribers also will generate benefits to all customers by increasing system efficiency. System load factor improvement benefits all utility customers because it allows a greater

number of units (kWh) to bear the overall fixed costs of the system without adding new capacity.

Flat Bill

Q. **Can you briefly describe Flat Bill?**

A. Flat Bill is an optional program offered by OG&E which allows the customer to pay a fixed amount each month of the one-year contract period, regardless of their monthly energy consumption. The customer receives a recomputed offer each year and must choose whether to continue under the program at that time. The fixed monthly bill amount is calculated based on the individual customer's expected usage during the contract period and includes a risk-based premium charge. FB is a premium price program and is not a least cost or discount rate. A customer that elects to take service under the FB rate is not affected by weather-based usage fluctuations, usage changes for non-weather related reasons or any changes to OG&E's rates or fuel prices during the contract year. FB charges are recomputed in each successive year as the customer renews participation.

Under the program, the offer amount will be defined by a Commission approved tariff and will be cost based. The cost basis is provided through the calculation of offers using the standard tariff for the offer and usage modified to reflect risk, expected changes in fuel cost, customer behavior changes, and weather normalization.

Q. **Why is OG&E proposing to implement Flat Bill in its Arkansas jurisdiction?**

A. OG&E's recent pricing research, described in detail by Mr. Scott, indicates that approximately 31% of customers would choose to participate in FB over other similar services offered by the Company. In addition, this program has been very successful and popular with OG&E's Oklahoma jurisdiction customers. Many customers value the security and stability a fixed bill product can offer and are willing to pay a premium to eliminate the price and usage risk associated with their electric bill.

Q. **Is Flat Bill a replacement to the Levelized Billing Plan currently offered in Arkansas**?

A. No. FB is a distinctly different program. Under the Levelized Billing Plan the customer pays the average of their previous twelve months bills. Unlike Flat Bill, a customer who

exits the Levelized Billing Plan will pay or receive a true-up amount. Flat Bill delivers price security but does not incorporate an annual true-up of shortfalls or overpayments. While the Levelized Billing Plan is a good solution for some customers, OG&E has discovered, through our experience in Oklahoma, that other customers strongly prefer Flat Bill.

Q. **Has OG&E's flat bill program been successful in Oklahoma?**

A. Yes. OG&E's Oklahoma flat bill program has a renewal rate of approximately 86% which indicates that customers are satisfied with the results they receive from the program and wish to continue receiving the benefits offered by a fixed bill plan. OG&E began offering the program in Oklahoma beginning in 2006. Now, almost 45,000, or approximately 7%, of our Oklahoma residential customers have chosen the program. The flat bill rate has been successful with OG&E's Oklahoma General Service class as well, with about 2,000 subscribers.

Q. **What happens if a Flat Bill customer increases their usage dramatically?**

A. The tariff contains an "abuse" clause. Anyone who increases their usage by over 30% for three consecutive months may be subject to removal from the FB program and returned to the standard tariff. This abuse provision is necessary to manage the program risk and protect the interest of other participants who do not abuse the program.

Q. **What happens when a customer does not complete the contract year?**

A. The customer's actual usage while on FB will be applied against the standard rate. If the standard rate charges are higher than the FB payments, the customer will be required to pay the difference. If the standard rate charges are lower than the FB payments, no adjustment will be made. This is desirable for a couple of reasons: 1) to prevent customers from "gaming" the program by playing one tariff against another, and 2) to mitigate the risk of the FB program.

Q. **Which customers are allowed to participate in Flat Bill?**

A. To be eligible, customers must simply meet certain restrictions surrounding the ability to accurately determine future consumption (such as twelve months of history and

predictable usage pattern). No particular subset of customers will be excluded from the rate.

Q. **How will the tax exemption for low income customers be applied to the Flat Bill charges?**

A. Offers extended to each customer identified as tax exempt under the Arkansas Tax Code will include a determination of the percentage of the offer amount which is non-taxable based on the estimated usage used to calculate the offer under the standard tariff. Monthly billing will apply taxes to the taxable portion determined during the offer calculation.

Q. **How will a customer's offer amount be computed under the program?**

A. First, OG&E will obtain each customer's individual kilowatt hour usage history. The usage would then be adjusted to account for weather and changes in behavior to determine the 12-month projection of usage. The customer's offer will then be computed using the standard rate including the expected fuel cost and all applicable riders. Finally, the bill amount will be adjusted for the risk premium resulting in a customized FB offer to the customer to be billed evenly over twelve monthly billing cycles during the contract period.

Q. **Please explain the process for determining the risk premium applied to the bill amount?**

A. The risk premium is determined through quantification of the program's risk components. The sources of risk in the program include weather risk, usage risk due to unexpected growth, and the risk that underlying costs will change over the contract period. The estimate of weather risk exposure is based on the usage variance arising from abnormal weather conditions. OG&E approximates the projected exposure caused by usage uncertainty due to unexpected growth based on factors other than weather. The underlying cost uncertainty over the contract period includes factors like fuel cost and impending base rate changes.

Q. **What is the current risk premium in Oklahoma?**

A. As of August 2010, the risk premium applied to Oklahoma offers is 3.5%. The proposed tariff limits the risk premium to 10%.

Q. **What is the Company's proposed regulatory treatment for the Flat Bill program?**

A. The Company proposes that the Commission determine that any gain or loss in revenues associated with this program (when compared to the actual billing which would occur under the standard rate for the actual usage in each month) would be considered as a below the line item for regulatory accounting purposes. This treatment insulates other customers from the risks associated with this program, as well as ensures that shareholders are held responsible for costs beyond the actual FB payments.

Q. **Does the Flat Bill rate violate Section 2(g)(1)(G) of the Arkansas promotional practice rules?**

A. No. Section 2(g)(1)(G) lists guaranteeing the maximum cost of electric service as a promotional practice. OG&E's FB program does not guarantee a maximum cost of electric service since offers are different for different consumption patterns and levels. A customer that consumes energy within the guidelines of the FB tariff will be provided electric service at a predetermined monthly billing amount based on the expected future kWh consumption for the next twelve month period. Renewal offers take into account the actual historic usage and current standard rate tariff provisions ensuring an annual adjustment that reflects costs. Customers who do not complete their contract term or who consume excessive energy amounts will be billed at the standard tariff for actual usage. In summary, OG&E believes the proposed Flat Bill program does not violate the promotional practice rules because the Flat Bill rate is directed entirely towards existing customers and because their historic consumption is used to determine the offer.

<u>Load Reduction Program</u>

Q. **Why are load reduction programs appropriate?**

A. OG&E is required to ensure the reliability of its system by providing sufficient generation capabilities. However, there are times when system constraints or other circumstances arise and impact our ability to meet this requirement. When these

circumstances present themselves, the Company seeks other supply sources or acts to reduce energy consumption on its system. Load reduction programs are a means to attain a voluntary reduction of consumption by requesting that individual customers reduce their consumption during periods when system constraints exist. Typically, these programs reward customers for their commitment to reduce consumption during a period when demand is expected to exceed supply. These programs help OG&E ensure firm supply for our customers.

Q. **What are the major features of OG&E's proposed Load Reduction ("LR") rider?**

A. The LR rider is designed to compensate customers for usage reductions through tiered credits based on a commitment level and actual performance during a curtailment event. Customers commit to various levels of load reduction performance using a menu of options within the program that best match their operations and response capability. The program allows a customer to choose the amount of load to curtail (Subscribed Curtailment Load or "SCL"), the required notification period (30 minutes or 4 hours) and a limit to the number of on-peak hours they will be required to curtail (40, 80 or 160 hours) during the contract year. Additionally, a customer participation factor will provide a premium to customers that continue to participate in the program in subsequent years. The subscription credit is paid for the customer-elected curtailment level at a rate based on the options selected by that customer. Performance credits are earned by the customer based on their actual reduced load during a curtailment event. Additionally, customers who commit to reduce load will have an option not to curtail (or to "buy through the event") during the curtailment period if specific circumstance prevent partial or full compliance with the selected options.

Q. **Does the Company currently offer a Load Reduction Program to its Oklahoma customers?**

A. Yes. However, there is no load reduction program currently available to Arkansas customers.

Q. **Who is eligible to participate in the proposed Load Reduction program?**

A. The program will be available to OG&E's PL and PL-TOU customers served with a peak period maximum demand of at least 200 kW. Since interval metering and timely data collection is required to administer the program, customer participation is subject to the availability or installation of the appropriate meter and communications equipment at the customer site.

Q. **How will the subscription credit be determined?**

A. A subscription credit is similar to a capacity reservation charge. Each year, prior to the enrollment period, OG&E will update the subscription prices for the upcoming curtailment period. Subscription credits will be calculated by multiplying the customer's SCL by the published subscription price, adjusted for customer selected option and system losses. Subscription credits will be paid only during the four peak months (June through September).

Q. **Please describe the Subscribed Curtailment Load ("SCL").**

A. The SCL is the amount of load selected by the customer that the customer agrees to reduce during a curtailment event. The SCL can range from 0 kW up to the customer's historical peak period (2 pm to 7 pm) maximum demand. If a customer selects an SCL of 0 kW, the customer will receive no subscription credits. However, the customer will be eligible to receive performance credits earned during a curtailment event.

Q. **What other choices must a customer make and how do these options affect the subscription credits?**

A. Customers must choose a minimum notification time of either 4 hours or 30 minutes. Additionally, the customer can choose to limit the total hours of required curtailment to 40, 80 or 160 hours during the curtailment contract period. Customers selecting 4 hour notification and 40 total hours of curtailment will receive the base subscription credit. Selection of a 30-minute price notification will provide a 10% premium to the base subscription credit. Selection of the 80 or 160 curtailment-hour limits will add an additional 10% or 25% premium, respectively, to the subscription credit.

Q. **How do customers earn performance credits**?

A. When OG&E issues a curtailment event notice to reduce load during a specified time, customers will receive performance credits based on the actual curtailed load during the event and the curtailment price for the event. The curtailment price will be determined and communicated to the customers at the time they are notified of the event. A minimum curtailment price will be posted with the subscription price to ensure that customers understand the minimum compensation they will receive for any load reduction event. The actual curtailment price for any event may be higher than the minimum price if OG&E's system conditions indicate the value exceeds that price. The curtailment level is determined as all energy reduced below the individual customer's Customer Baseline Load ("CBL"). A CBL is the customer's average hourly loads over the most recent five workdays. Performance credits are calculated for each hour or portion of an hour for the curtailment event and the total credit for the event is the sum of the hourly credits.

Q. **What happens when a customer fails to reduce load by their subscribed amount?**

A. Curtailment events are evaluated differently for on-peak and off-peak time periods. During on-peak time periods (defined as Monday through Friday from 12 pm to 8 pm, during the months of June through September, excluding observed Company Holidays) Customers must reduce load from their CBL by the subscribed amount in order to avoid the requirement to buy-through the curtailment event. If a customer is unable to reduce load to the required level, their buy through cost is equal to twice the announced curtailment price in each hour that the SCL level is not achieved. During off-peak times, the price for the buy-through will be equal to the curtailment price for the event. Customers who have an SCL of 0 kW are not affected by the buy-through provision of the curtailment event.

Q. **Will a customer be removed from the program if they fail to perform as agreed?**

A. Customers will not be removed from the program. However, if a customer consistently fails to reduce load during curtailment events, the Company may choose to disqualify the customer for future enrollment or require a reduced SCL from the customer during a succeeding enrollment period.

Q. **How does OG&E propose to recover the credits paid to customers under the Load Reduction program?**

A. The proposed Customer Education and Demand Response rider provides the mechanism for recovering the net cost of the Load Reduction program. The Southwest Power Pool ("SPP") and Federal Energy Regulatory Commission ("FERC") recognize load reduction programs as firm capacity and the Company believes it is appropriate to pass through the cost of these programs to all customers.

Day Ahead Pricing

Q. **What changes are proposed to the DAP program?**

A. The Company is proposing that the DAP program be converted from a pilot program to a standard tariff with some modifications. The modifications include removing the administration charge and instituting a Risk and Recovery Factor ("RRF") for the hourly price calculation.

Q. **Why should DAP be made permanent?**

A. The DAP has proven beneficial to OG&E's largest Arkansas customer which has utilized DAP continuously since July 2009.

Q. **What is the proposed risk and recovery factor?**

A. The proposed RRF is a fixed adder of 5 mills (0.5¢) per kWh to the DAP hourly price.

Q. **Why is the RRF appropriate?**

A. There are three main reasons why RRF should be included in the hourly prices. First, the RRF is a vehicle to recover program implementation and administration costs. Second, after a year of experience with the DAP, the Company believes it is appropriate to recognize the risks associated with setting prices based on a day ahead forecast. Third, inclusion of the RRF allows OG&E to earn a return on the incremental sales above the CBL. The pilot program did not include a return on those sales. All customers benefit through increased reliability when DAP participants reduce load in response to higher prices. However, absent a return component, OG&E foregoes the opportunity to receive the margin on the increased sales.

Schedule H

Q. **What is included in Schedule H?**

A. Schedule H includes the Proof of Revenue which demonstrates that the proposed tariffs produce the revenue requirement requested by the Company. Schedule H also provides information about how the proposed prices affect customers.

Q. **What is the total revenue requirement for the Arkansas jurisdiction used to develop the proposed rates?**

A. The Arkansas jurisdictional total revenue requirement is $100,380,586 which creates a revenue deficiency of $17,723,253, an increase of 10.35%.

Q. **What are the revenue change and the resulting impact to each customer class?**

A. The Arkansas jurisdictional change in revenue and overall impact for each class of service is provided in Chart 2. These are shown in H-1, Summary of Revenue by Rate Class.

Chart 2

Customer Group (Rate Class)	*Revenue Change*	*Percent Change*
Residential	$5,710,194	10.6%
General Service	$1,649,749	10.4%
Power & Light	$4,965,198	11.4%
PL-TOU	$5,475,004	10.2%
Municipal Pumping	$16,212	14.2%
Athletic Field Lighting	$16,048	19.2%
Lighting (OSL and LM)	($150,130)	-3.8%
Total Arkansas Jurisdiction	**$17,682,274**	**10.3%**
Requested Rate Increase	**$17,723,253**	**--**
Rate Design Difference	**($40,979)**	**--**

Q. **Why is there a $40,979 rate design difference?**

A. The design to recover the $100,380,586 cost of service is structured over 2.77 billion kWh or billing units. A slight move in a rate can increase or decrease the revenues a significant amount. In this case, it is impractical to design rates that precisely recover the revenue deficiency of $17,723,253.

Rate Design Principles

Q. **Please describe the principles OG&E utilized to develop the proposed rate design.**

A. OG&E based its rate design on industry established and accepted principles. First and foremost, the Company structures its rate design to allow recovery of the revenue requirements, encourage efficient use of its resources, and provide customers with choices aligned with their desires. To this end, we have incorporated marginal prices into our rate design for tail-block pricing and on-peak pricing to create the desired efficiencies within the available pricing plans. Secondly, OG&E considered the aspects of the rate making principles outlined by James C. Bonbright in his book, *Principles of Public Utility Rates*[1]. Specific customer impact and unit cost analyses were performed to provide insight into the soundness of our rate design when evaluated against Bonbright's principles.

Q. **Is it possible to strictly adhere to each of Bonbright's principles during the rate design process?**

A. Not entirely. As rates are designed, there are trade-offs between conflicting principles to establish the most appropriate rate design. It is important to realize that regardless of how important one single criterion may seem, the principles are intended to be used as guidelines and must be taken in context with the other criteria.

Q. **What analyses did OG&E perform regarding the proposed rate design?**

A. OG&E conducted an impact analysis and unit cost analysis of the proposed rates during its rate design process. The impact analysis assisted the Company in ensuring that customers were not unduly impacted by our proposed rate changes. To evaluate the rate design to ensure that pricing is fair, OG&E performed unit cost analyses to ensure that the rates properly allocate costs to various segments of customers within their respective

[1] Bonbright, James C.; Principles of Public Utility Rates, Second Edition, 1988, pages 383-384.

classes. The Company's unit cost analysis helped OG&E understand how the overall rate design applied the appropriate costs to various customers or customer segments. Again, the Company must balance the objectives of rate design and occasionally incorporate compromise between conflicting criteria in the rate design based on our discoveries through these analyses.

Unit Costs

Q. **Why is it important to understand what the unit costs are when designing rates?**

A. The unit costs are important when assessing the proper recovery of embedded costs from customers or customer segments within each rate class, *i.e.* the intra-class allocation of embedded costs. If fairness were the only criterion for rate design, the unit costs would define the most appropriate rate design.

In addition, when designing rates, a common misconception is to assume that the existing rates continue to be of sound design and fairly collect revenues from customers. When this assumption is made, any flaws that may exist in the original rate design are perpetuated in ensuing rate designs. The previous balance of principles incorporated in the existing rates may not be appropriate for current costs or circumstances. It is important that the rate itself is evaluated in its entirety and not simply in the context of the proposed changes.

Q. **What do you mean by functionalized and classified cost components?**

A. Functionalized cost data breaks the cost of service revenue requirement into the production, transmission, distribution and customer functions. Classified cost data provides a separation of the cost of service revenue requirement into customer, demand, and energy components that correspond to how customers are billed. Unit costs are developed from the functionalized and classified cost components in the cost of service model and are determined for each class and service level of customers.

Q. **Will you please explain these components?**

A. The demand component is comprised of that portion of the revenue requirement associated with the capacity of the system related to the production, transmission, distribution and customer functions. In like manner, the energy component is the portion

of revenue requirement associated with the variable O&M related to the production function. Finally, the customer component is that portion of revenue requirement directly associated with the distribution function which enables the delivery and support of electricity to the customer (*e.g.* wires, poles, line transformation, service connection, metering and billing and customer service activities).

Q. **Can any of the components be further disaggregated?**

A. Yes. The production demand portion of the demand component can be further separated using the functionalized costs into peak and average demand components. The peak portion is directly related to the demand constraints placed on the generation system. The average portion is directly related to the energy production. OG&E disaggregated the production demand component using the peak and average components of the 1CP and Average cost allocation methodology by rate class and service level.

Q. **What is the value of having the components, and their sub-categorization, by rate class and service level?**

A. The component revenue requirements are divided by *pro forma* billing units, in each applicable rate category and service level, to determine what the tariff rate per billing unit should be in an embedded cost based rate structure. The resulting unit costs are used to evaluate rate designs for the proper allocation of costs to specific customers or customer groups.

Q. **How were the functionalized cost components combined with the billing units to determine unit costs?**

A. The three billing components are typically the customer charge, the demand charge, and the energy charge. Component costs are typically applied to the billing units based on their fixed or variable nature. However, some tariffs have only a customer and energy charge, which requires recovery of fixed costs through either the customer component or through the energy charge.

Q. **Are there any issues with recovering fixed costs in variable billing units?**

A. Yes. There are two main issues with energy (variable) billing determinants. First, recovering fixed costs through variable rates subjects the recovery of fixed costs to fluctuations in energy usage. Second, having fixed costs included in energy rates distorts price signals to customers and may inadvertently cause changes to their consumption pattern, leading to an inefficient use of resources.

Q. **Did you allocate any of the cost components based on seasonality in your unit cost determinations?**

A. Yes. The peak portion of production demand is related to meeting the production capacity needs of our customers' load during the peak season. Since the Company is a summer peaking utility, those costs were allocated to summer components.

Q. **Have you developed a unit cost for each rate category and service level based on the component cost revenue requirements?**

A. Yes. Exhibit GWT-1 provides the unit cost for each class and service level contained within our cost of service.

Q. **Would it be proper to set prices using only unit costs?**

A. No. It is important to keep in mind all objectives for rate design. For example, the impact to customers is an important consideration. It may take one or two sets of price changes (rate cases) to transition current rates to unit cost levels. Unit costs provide an embedded cost basis for each rate and represent the fairest division of costs among customer classes; however, this is not always the most appropriate pricing, since it does little to incorporate the variations of costs by time periods (*e.g.* hourly marginal costs). Therefore, while unit costs are very important, other criteria must also be considered when establishing prices and tariff structures. Our proposed prices reflect what we believe is a realistic and reasonable balance between embedded costs, marginal costs, customer preferences, and recovery of the proposed revenue requirement without undue impacts on customers.

Residential Rate Design

Q. **Please describe the proposed changes to OG&E's current residential rates.**

A. The proposed changes to the Residential Standard ("RS") tariff include an increase in the monthly customer charge to more accurately reflect the fixed cost of providing electric service to a customer, a change to the step for the summer season first block and price changes to the first block and tail-block in both summer and winter. The tail-step prices have been aligned with the marginal cost of energy during the respective season. The proposed rate changes are presented in Chart 3, below.

Chart 3 - Comparison of Residential Prices

RS Monthly Prices	*Proposed*	*Current*
Monthly Customer Charge	$15.50	$7.15
Summer Season	**June-Oct**	**June-Oct**
First Block	0-1,400 kWh	0-1,500 kWh
First Block Price	3.5¢ per kWh	4.235¢ per kWh
Second Block	Over 1,400 kWh	Over 1,500 kWh
Second Block Price	7.4¢ per kWh	5.485¢ per kWh
Winter Season	**Nov-May**	**Nov-May**
0-600 kWh	3.5¢ per kWh	2.985¢ per kWh
Over 600 kWh	2.0¢ per kWh	2.06¢ per kWh

Q. **How much will the monthly customer charge increase?**

A. OG&E's current customer charge for RS customers is $7.15 per month. Our unit cost for the customer component on average is $24.21 (see Chart 4). Our proposed customer charge of $15.50 per month was selected to allow a significant movement toward the unit cost value. The Company did not feel it appropriate to move the price to the full cost.

Chart 4 - Residential Unit Cost: Customer Component

Customer Charge	Annual Billing Units	Miscellaneous Revenue	Customer	Dist Demand	Cust and Dist Less Miscellaneous	Unit Cost Price
	651,648	$ 467,363	$ 5,857,619	$ 10,388,285	$ 15,778,541	$ 24.21

Q. **What is the change to the kilowatt hour ("kWh") block structures for the Residential Standard tariff?**

A. As shown in Chart 3, the summer first block has been reduced from 1,500 kWh to 1,400 kWh.

Q. **Why is OG&E proposing that the block structure be modified?**

A. The Company adjusted the block structure for its residential class of customers for two reasons. First, to encourage more efficient utilization of resources, OG&E applied marginal pricing and expanded the tail-block slightly to expose a few more customers and additional energy sales to the tail-block (marginal) prices. The new block structure reaches 37.5% of our residential customers and includes 21.5% of summer energy sales in the summer tail-block. This is an increase of 4.5% and 2.7% respectively over the 1,500 block size. Second, this aligns the Arkansas and Oklahoma block structures for the residential class.

Q. **How will energy prices for residential customers change under OG&E's proposed rate design?**

A. OG&E proposes a decrease of approximately $0.007 per kWh to the price for summer season (usage billed during the months of June through October) initial block (0 to 1,400 kWh) usage and proposes an increase of approximately $0.019 per kWh for all usage above 1,400 kWh. This increase moves the tail-step price to a level that approximates the summer season costs. This clear signal incents customers to reduce energy usage during the higher cost periods and helps mitigate the need to build additional generating capacity.

OG&E proposes a minor increase (less than $0.006 per kWh) to the initial block (0 to 600 kWh) price for the winter season and proposes to reduce the additional usage price from $0.0206 to $0.02 per kWh. The unit cost study shows that the winter season energy components are approximately $0.018 per kWh.

Q. **What is the impact of the proposed rate design changes to residential customers?**

A. The overall average impact to the residential customers included in the analysis is a monthly increase of about 10.6% or $9.07. In order to assess the rate design for

customers with different characteristics within the class, the impact analysis was performed across several sub-groups of customers based on size, income level and seasonality of use. The impacts for each of the defined sub-groups are shown in Chart 5.

Chart 5 – Residential Customer Impact Results

Segmented Results Current RS VS Proposed RS											
Segment	Number of Customers	Current RS Revenue	Proposed RS Revenue	Total Impact	Percent Impact	Annual kWh	Average Monthly kWh		Current Average	Proposed Average	Average Change
							Summer	Winter	$/Month	$/Month	$/Month
Total	41,085	$42,129,153	$46,602,526	$4,473,373	10.62%	13,629	1,303	1,088	$85.45	$94.52	$9.07
Zero Users	115	$9,867	$21,390	$11,523	116.78%	-	-	-	$7.15	$15.50	$8.35
Small Users	3,953	$1,194,113	$1,576,374	$382,261	32.01%	3,064	312	231	$25.17	$33.23	$8.06
Normal Users	31,736	$30,033,028	$33,160,646	$3,127,618	10.41%	12,431	1,228	963	$78.86	$87.07	$8.21
Large Users	5,281	$10,892,145	$11,844,116	$951,971	8.74%	29,036	2,526	2,502	$171.88	$186.90	$15.02
Low Income	3,323	$3,085,520	$3,414,839	$329,319	10.67%	12,408	1,090	1,063	$77.38	$85.64	$8.26
Not Low Income	37,762	$39,043,633	$43,187,688	$4,144,054	10.61%	13,737	1,322	1,090	$86.16	$95.31	$9.15
Summer Users	15,793	$14,788,116	$16,591,208	$1,803,092	12.19%	11,740	1,439	705	$78.03	$87.55	$9.51
Winter Users	6,101	$6,503,741	$7,084,857	$581,116	8.94%	15,307	888	1,644	$88.83	$96.77	$7.94
Non-Seasonal	19,191	$20,837,296	$22,926,462	$2,089,165	10.03%	14,650	1,323	1,226	$90.48	$99.55	$9.07

Q. **How did the Company calculate the impact of these changes to customers?**

A. OG&E computed the monthly billing amount for customers with twelve months of test year data under the current prices and compared result to the bill amount calculated for those same customers under the proposed rate. The impact to customers was determined using data extracted from the Company's billing system for 2009 actual usage data which was adjusted to reflect normal weather. Customers without a complete year of usage data were excluded, resulting in an analysis of approximately 41,000 customers. Various sub-categories based on customer size, income level and seasonality of consumption were analyzed.

Q. **How were residential customers segmented by size?**

A. Four classifications of customers were created based on size. The first classification consisted of customers that used no energy (even though they were connected to the OG&E system) during the test year. Low use and high use customer segments were identified by determining the average (mean) annual usage (13,629 kWh) and standard deviation (8,391 kWh) and identifying those that fell below one standard deviation from the mean as low use and those that fell above one standard deviation from the mean as

high use. All other customers were classified as standard use. The results are shown in Chart 5.

Q. **What are zero use customers?**

A. A zero use customer is a customer that, although connected to the OG&E system for each of the twelve months throughout the test year, used no energy during that time frame. Although very uncommon, these customers do exist within the OG&E service territory. A brief review of the customer information for these accounts indicates that these "customers" are typically vacated dwellings or vacant rental properties.

Q. **What is the expected impact to the zero use customers?**

A. This segment of residential class will receive an increase or $8.35 per month which is less than the class average increase.

Q. **Do you believe that this is a reasonable increase for these customers?**

A. Yes. These customers could avoid all charges by simply requesting disconnection from OG&E's system. If zero use customers do not pay their fair share of cost, other residential customers must "pick up the tab". I believe that it is important to establish fair prices for all customers; and 0.2% of customers should not be allowed to force an inequity upon all others.

Q. **What is the proposed increase for low income customers?**

A. As shown on Chart 5, low income customers received on average a 10.67% or $8.26 increase per month.

Q. **How does OG&E determine which customers should be classified as low income?**

A. Customers that receive the low income sales tax exemption and those customers that have received, during the test year, any assistance with utility bill payments are defined as low income customers. This is approximately 8% of the residential class.

Q. **Are the usage characteristics of low income customers noticeably different from other residential customers?**

A. No. There does not appear to be any meaningful difference between the usages of low income customers versus not low income customers. Chart 6 shows a comparison of low income and not low income customers within the defined segments for consumption level and seasonality during the test year. The distribution across the customer size segments, especially the normal user segment, is similar between the low income and not low income group. There does appear to be a tendency for low income customers to have slightly lower summer consumption than the other customers and the low income segment used slightly less electricity in total.

Chart 6: Low Income versus Not Low Income Customer Characteristics

Segmented Results Current R-1 VS RS-A1 - Low Income Customers					
Segment	Number of Customers	% of Total	Annual kWh	Average Monthly kWh	
				Summer	Winter
Total	3,323	100%	12,408	1,090	1,063
Zero Users	5	0.2%	-	-	-
Small Users	423	12.7%	3,426	360	251
Normal Users	2,558	77.0%	11,902	1,077	996
Large Users	337	10.1%	27,703	2,113	2,607
Summer Users	947	28.5%	9,397	1,160	562
Winter Users	672	20.2%	14,913	852	1,611
Non-Seasonal	1,704	51.3%	13,093	1,144	1,126

Segmented Results Current R-1 VS RS-A1 - Not Low Income Customers					
Segment	Number of Customers	% of Total	Annual kWh	Average Monthly kWh	
				Summer	Winter
Total	37,762	100%	13,737	1,322	1,090
Zero Users	110	0.3%	-	-	-
Small Users	3,530	9.3%	3,021	306	228
Normal Users	29,178	77.3%	12,477	1,241	960
Large Users	4,944	13.1%	29,127	2,554	2,495
Summer Users	14,846	39.3%	11,890	1,457	714
Winter Users	5,429	14.4%	15,356	893	1,648
Non-Seasonal	17,487	46.3%	14,802	1,341	1,236

Q. **How was the designation of summer and winter users determined?**

A. The customers were segmented based on a seasonality ratio that determines the ratio of summer season to total electricity use. This entails determining the average (or mean) and the standard deviation of the summer ratio (43% and 12%, respectively). All customers that have a ratio of greater than one standard deviation above the mean were classified as summer users and likewise, those that had a summer season ratio one standard deviation below the mean were considered winter users.

Q. **Why is it important to analyze impacts with respect to seasonality of usage?**

A. Customers that use a greater proportion of their total energy during the summer months create higher costs than other customers. Causality of cost must be identified and incorporated into rate design to ensure the proper price signals are presented to customers during the appropriate seasons. Conversely, customers that have a lower proportion of summer usage are utilizing lower cost energy to fulfill their total energy needs. The proposed summer season price differential between the initial block and the tail block was set to send a clear price signal to reflect the increasing cost of capacity and to encourage the wise use of electricity during higher cost periods.

Q. **Did you assess the proposed rates against the unit cost for the residential class?**

A. Yes. In order to ensure that there are limited intra-class subsidies we compared the billing under the proposed rates to the billing under a unit cost based rate. Chart 7 shows the results of this comparison. A percent difference that is less than zero indicates those segments in which customers typically pay less than the unit costs associated with their usage (*i.e.* are being subsidized) while a positive difference indicates those segments that are paying more than their share of the costs. The average difference column indicates the average absolute difference relative to the unit cost. For example, a small use customer is paying, on average, 14%, or $5.59 less than unit costs indicate should be paid. The Company believes the proposed residential rate design, while not perfect, represents a reasonable movement toward eliminating intra-class subsidies.

Chart 7. Comparison of unit costs and proposed rate for residential customers.

Segmented Results Unit Costs VS Proposed RS											
Segment	Number of Customers	Unit Costs Revenue	Proposed RS Revenue	Total Difference	Percent Difference	Annual kWh	Average Monthly kWh		Current Average	Proposed Average	Average Difference
							Summer	Winter	$/Month	$/Month	$/Month
Total	41,085	$46,585,378	$46,602,526	$17,148	0.04%	13,629	1,303	1,088	$94.49	$94.52	$0.03
Zero Users	115	$33,410	$21,390	($12,020)	-35.98%	-	-	-	$24.21	$15.50	($8.71)
Small Users	3,953	$1,841,413	$1,576,374	($265,039)	-14.39%	3,064	312	231	$38.82	$33.23	($5.59)
Normal Users	31,736	$33,053,293	$33,160,646	$107,354	0.32%	12,431	1,228	963	$86.79	$87.07	$0.28
Large Users	5,281	$11,657,262	$11,844,116	$186,854	1.60%	29,036	2,526	2,502	$183.95	$186.90	$2.95
Low Income	3,323	$3,427,253	$3,414,839	($12,414)	-0.36%	12,408	1,090	1,063	$85.95	$85.64	($0.31)
Not Low Income	37,762	$43,158,125	$43,187,688	$29,563	0.07%	13,737	1,322	1,090	$95.24	$95.31	$0.07
Summer Users	15,793	$16,676,187	$16,591,208	($84,980)	-0.51%	11,740	1,439	705	$87.99	$87.55	($0.45)
Winter Users	6,101	$7,078,725	$7,084,857	$6,132	0.09%	15,307	888	1,644	$96.69	$96.77	$0.08
Non-Seasonal	19,191	$22,830,465	$22,926,462	$95,996	0.42%	14,650	1,323	1,226	$99.14	$99.55	$0.42

Residential Time-of-Use ("R-TOU") Rate Design

Q. **What is the status of the R-TOU approved by this Commission in Docket 08-103-U?**

A. This rate was implemented in June 2009. The first customer subscribed in November 2009. At the end of the test year (2009) there were eleven subscribers taking service on the RTOU rate. Since that time, the subscribed customer count has increased to approximately 600 customers.

Q. **What changes are you proposing to the R-TOU rate?**

A. The Company is proposing several minor changes.

1. Change the 1 pm-7 pm time-of-use period to 2 pm-7 pm.
2. Update the prices to reflect the marginal costs.
3. Update the customer charge.
4. Include a reduced customer charge for senior citizens.
5. Modify the best bill provision.

Q. **Please describe why OG&E made these changes.**

A. The time of use period change aligns the OG&E time of use period in Arkansas with that in Oklahoma. The energy pricing has been updated to reflect marginal cost and the proposed Time-of-Use provisions in the ECR rider. The customer charge was updated to conform to the standard residential rate. In order to encourage subscription by a valuable, yet reluctant to subscribe, segment, the customer charge is reduced $5.00 for all senior citizens during the summer months. The best bill provision has been modified from a month-to-month determination to an annual determination to account for all differences between the standard rate and the R-TOU rate.

Q. **Are you proposing similar changes to the Commercial Service TOU ("CS-TOU") rate?**

A. Yes. Except for the senior citizen discount, all of the modifications to the R-TOU rate have been made to the CS-TOU tariff.

General Service Rate Design

Q. What are the proposed changes to the General Service ("GS") tariff?

A. OG&E proposes an increase to the customer charge, the addition of an inclining block summer price schedule, changes to the summer season prices and a modification to the winter season block definition. Chart 8 below shows the proposed prices and the current prices.

Chart 8. Comparison of GS Current and Proposed Rates.

GS Monthly Prices	*Proposed*	*Current*
Monthly Customer Charge	$32.00	$21.75
Summer Season	June-Oct	June-Oct
0 to 5,000 kWh	3.9¢ per kWh	4.284¢ per kWh
Over 5,000 kWh	5.6¢ per kWh	4.284¢ per kWh
Winter Season	Nov-May	Nov-May
0 to 1,750 kWh	2.6¢ per kWh	2.284¢ per kWh
Over 1,750 kWh	1.8¢ per kWh	1.484¢ per kWh

Q. **What is the unit cost for the customer charge component?**

A. The unit cost customer charge for the GS Service Level 5 class was determined to be $42.26 as shown in Chart 9 below. The proposed customer charge of $32.00 is approximately 34% below unit cost.

Chart 9. Determination of unit cost for the GS SL-5 customer component.

Customer Charge	Annual Billing Units	Miscellaneous Revenue	Customer Component	Dist Demand	Cust and Dist Less Miscellaneous	Unit Cost Price
	111,276	$ 76,235	$ 1,235,671	$ 3,542,583	$ 4,702,019	$ 42.26

Q. **Why is OG&E proposing a modification of the GS block structures?**

A. The Company adjusted the block structure for its GS class of customers to encourage more efficient utilization of resources. As in the design of the residential rate, OG&E

applied marginal pricing, added an inclining block structure to the summer rates and expanded the declining winter first block.

Q. **What is the impact of these changes to GS SL-5 customers?**

A. As shown in Chart 10, the average impact to a GS SL-5 customer is approximately 10.43 percent, or $14.44 per month increase. The chart also shows the impact to customers segmented by size and seasonality.

Chart 10. Customer impacts of GS SL-5 customers.

Segmented Results Current GS VS Proposed GS											
Segment	Number of Customers	Current GS Revenue	Proposed GS Revenue	Total Impact	Percent Impact	Annual Use	Average Monthly Use		Current Average	Proposed Average	Average Difference
							Summer	Winter	$/Month	$/Month	$/Month
Total	8,142	$13,529,347	$14,939,789	$1,410,443	10.43%	22,510	9,131	13,379	$138.47	$152.91	$14.44
Zero Users	105	$27,405	$40,320	$12,915	47.13%	-	-	-	$21.75	$32.00	$10.25
Small Users	4,071	$2,089,892	$2,594,825	$504,934	24.16%	3,876	288	360	$42.78	$53.12	$10.34
Large Users	4,071	$11,439,456	$12,344,964	$905,509	7.92%	40,230	3,364	3,463	$234.17	$252.70	$18.54
Summer Users	3,296	$7,065,819	$7,685,823	$620,004	8.77%	28,893	3,482	1,941	$178.65	$194.32	$15.68
Winter Users	4,846	$6,463,529	$7,253,967	$790,438	12.23%	17,401	1,467	1,490	$111.15	$124.74	$13.59

Q. **How did OG&E determine the impact of these changes to customers?**

A. OG&E determined the impact using the same method described for residential customers. A database of all GS customers with a complete year of data was created that included 8,142 customers. The impact was determined by computing annual bills under the current prices, the proposed prices, and then determining the difference in revenue. Customers were segmented by size and seasonality and analyzed.

Q. **What were the results of the unit cost analysis for the GS customers?**

A. The results for the unit cost run are shown in Chart 11.

Chart 11. Comparison of unit costs and proposed rates for GS SL-5 customers.

Segmented Results Unit Cost VS Proposed GS											
Segment	Number of Customers	Unit Cost Revenue	Proposed GS Revenue	Total Difference	Percent Difference	Annual Use	Average Monthly Use		Current Average	Proposed Average	Average Difference
							Summer	Winter	$/Month	$/Month	$/Month
Total	8,142	$14,927,987	$14,939,789	$11,803	0.08%	22,510	9,131	13,379	$152.79	$152.91	$0.12
Zero Users	105	$53,374	$40,320	($13,054)	-24.46%	-	-	-	$42.36	$32.00	($10.36)
Small Users	4,071	$2,966,238	$2,594,825	($371,413)	-12.52%	3,876	288	360	$60.72	$53.12	($7.60)
Large Users	4,071	$11,961,749	$12,344,964	$383,215	3.20%	40,230	3,364	3,463	$244.86	$252.70	$7.84
Summer Users	3,296	$7,540,897	$7,685,823	$144,926	1.92%	28,893	3,482	1,941	$190.66	$194.32	$3.66
Winter Users	4,846	$7,387,090	$7,253,967	($133,123)	-1.80%	17,401	1,467	1,490	$127.03	$124.74	($2.29)

Municipal Pumping ("PM") Rate Design

Q. **What is the proposed disposition to the PM Rate?**

A. OG&E proposes that this rate be closed to new customers and that the GS rate be the default rate for any new customers in the future. Current PM customers would remain on the PM rate until such time that they choose to move to the GS rate or other applicable tariff (*e.g.* CS-TOU).

Q. **Why should the Commission approve that this rate be closed?**

A. In general, charges to the majority of the existing customer's charges would be reduced under the CS-TOU rate. OG&E believes that new customers should not be allowed to select the PM rate and existing customers should be encouraged to switch to the more advantageous rate. OG&E intends to provide information to the current PM customers on the availability of the CS-TOU tariff and encourage their migration to that rate.

Q. **What are the proposed rate changes to the PM rate?**

A. OG&E proposes to increase the customer charge to $32.00 per month. In order to meet the revenue requirement for this class, the Company proposes to increase the kWh prices to 3.4¢ per kWh for the summer season and to 3.0¢ per kWh for the winter season. A comparison of current and proposed rates is shown in Chart 12. The result is an average increase of approximately 14%.

Chart 12. Comparison of current and proposed PM rates.

PM Monthly Prices	*Proposed*	*Current*
Monthly Customer Charge	$32.00	$28.00
Summer Season	June-Oct	June-Oct
All kWh	3.4¢ per kWh	2.982¢ per kWh
Winter Season	Nov-May	Nov-May
All kWh	3.0¢ per kWh	1.982¢ per kWh

Athletic Field Lighting ("AFL") Rate Design

Q. **What is the Company proposing with regard to the AFL Rate?**

A. OG&E proposes that this rate be closed to new customers and that the GS rate be the default rate for new customers in the future. Under the GS rate, existing customers will continue to be eligible for the CS-TOU rate. Current AFL customers would remain on the AFL rate until such time that they choose to move to the GS rate or CS-TOU rate.

Q. **Why should the Commission approve that this rate be closed?**

A. In general, charges to the majority of existing customers would be reduced under the CS-TOU rate. OG&E believes that new customers should not be allowed to select these rates and existing customers should be encouraged to switch to the more advantageous rates. OG&E intends to provide information to current customers on the availability of the CS-TOU tariff and encourage their migration to that rate.

Q. **What are the proposed rate changes to the AFL rate?**

A. OG&E proposes to increase the customer charge to $32.00 per month. In addition, the Company proposes to increase the kWh prices to 5.4¢ per kWh in order to meet the class revenue requirement. A comparison of current and proposed rates is shown in Chart 13. The result is an average increase of approximately 19%.

Chart 13. Comparison of current and proposed AFL rates.

AFL Monthly Prices	*Proposed*	*Current*
Monthly Customer Charge	$32.00	$28.00
Summer Season	June-Oct	June-Oct
All kWh	5.4¢ per kWh	3.95¢ per kWh
Winter Season	Nov-May	Nov-May
All kWh	5.4¢ per kWh	3.95¢ per kWh

Power & Light ("PL") and PL Time of Use ("PL-TOU") Rate Design

Q. **Is OG&E proposing changes to the PL and PL-TOU tariffs?**

A. The Company is proposing price changes only to the PL rate design in order to provide a better alignment to the unit costs. For the PL-TOU customers, the Company is proposing a change from a demand based TOU rate structure to an energy based TOU rate structure.

Q. **Why are you proposing a change from a demand-based to an energy-based TOU rate?**

A. An energy-based TOU rate provides an increased incentive for customers to respond to time-based prices during the month. For example, a customer operating under a demand-based TOU rate incurs the majority of the charges for on-peak usage during the 15-minute interval in which the maximum on-peak demand occurs. To minimize average energy costs, the customer must consistently operate at that level for the remainder of the on-peak period during the billing cycle. A reduction in energy consumption below the demand level previously set in the billing period provides a limited economic benefit to the customer. However, under an energy-based TOU rate, the customer has incurred only the cost associated with the energy consumed during that interval. Reductions during the on-peak time period for the remainder of the billing cycle will reduce the customers average energy cost. Any reduction in energy consumption would result in a much greater benefit to the customer due to energy prices that more closely reflect the marginal costs.

Q. **What are the proposed prices for the PL and PL-TOU rates?**

A. These prices and the prices currently in effect are reflected in Charts 14 and 15.

Chart 14. Comparison of current and proposed PL rates.

PL SL-1	Proposed	Current
Monthly Customer Charge	$500.00	$300.00
All Seasons kWh	1.2¢ per kWh	0.389¢ per kWh
Summer Max kW	$6.50 per kW	$7.25 per kW
Winter Max kW	$1.95 per kW	$4.00 per kW
PL SL-2	**Proposed**	**Current**
Monthly Customer Charge	$300.00	$225.00
All Seasons kWh	1.2¢ per kWh	0.489¢ per kWh
Summer Max kW	$7.50 per kW	$8.00 per kW
Winter Max kW	$2.65 per kW	$5.75 per kW
PL SL-3	**Proposed**	**Current**
Monthly Customer Charge	$300.00	$225.00
All Seasons kWh	1.2¢ per kWh	0.489¢ per kWh
Summer Max kW	$9.70 per kW	$8.00 per kW
Winter Max kW	$6.30 per kW	$5.75 per kW
PL SL-4	**Proposed**	**Current**
Monthly Customer Charge	$85.00	$225.00
All Seasons kWh	1.2¢ per kWh	0.489¢ per kWh
Summer Max kW	$9.70 per kW	$8.00 per kW
Winter Max kW	$6.30 per kW	$5.75 per kW
PL SL-5	**Proposed**	**Current**
Monthly Customer Charge	$85.00	$75.00
All Seasons kWh	1.2¢ per kWh	0.589¢ per kWh
Summer Max kW	$9.70 per kW	$10.40 per kW
Winter Max kW	$6.30 per kW	$6.05 per kW

Chart 15. Comparison of current and proposed PL-TOU rates.

PL-TOU SL-1	Proposed	Current
Customer Charge		
	$500.00	$300.00
kWh Charge		
All Seasons kWh	N/A	0.397¢ per kWh
On-Peak kWh	7.10¢ per kWh	N/A
Off-Peak kWh	1.15¢ per kWh	N/A
Winter kWh	1.15¢ per kWh	N/A
kW Charge		
Summer On-Peak kW	N/A	$6.00 per kW
Summer Max kW	N/A	$1.25 per kW
Winter Max kW	N/A	$4.00 per kW
All Seasons kW	$1.95 per kW	
PL-TOU SL-2	**Proposed**	**Current**
Customer Charge		
	$300.00	$225.00
kWh Charge		
All Seasons kWh	N/A	0.497¢ per kWh
On-Peak kWh	8.20¢ per kWh	N/A
Off-Peak kWh	1.15¢ per kWh	N/A
Winter kWh	1.15¢ per kWh	N/A
kW Charge		

Summer On-Peak kW	**N/A**	**$6.25 per kW**
Summer Max kW	**N/A**	**$1.75 per kW**
Winter Max kW	**N/A**	**$5.75 per kW**
All Seasons kW	**$2.65 per kW**	

Chart 16. Comparison of current and proposed PL-TOU rates. (continued)

PL-TOU SL-3	**Proposed**	**Current**
Customer Charge		
	$300.00	**$225.00**
kWh Charge		
All Seasons kWh	**N/A**	**0.497¢ per kWh**
On-Peak kWh	**8.50¢ per kWh**	**N/A**
Off-Peak kWh	**1.15¢ per kWh**	**N/A**
Winter kWh	**1.15¢ per kWh**	**N/A**
kW Charge		
Summer On-Peak kW	**N/A**	**$6.25 per kW**
Summer Max kW	**N/A**	**$1.75 per kW**
Winter Max kW	**N/A**	**$5.75 per kW**
All Seasons kW	**$5.40 per kW**	
PL-TOU SL-4	**Proposed**	**Current**
Customer Charge		
	$85.00	**$225.00**
kWh Charge		
All Seasons kWh	**N/A**	**0.497¢ per kWh**
On-Peak kWh	**9.10¢ per kWh**	**N/A**
Off-Peak kWh	**1.20¢ per kWh**	**N/A**
Winter kWh	**1.20¢ per kWh**	**N/A**
kW Charge		
Summer On-Peak kW	**N/A**	**$6.25 per kW**
Summer Max kW	**N/A**	**$1.75 per kW**
Winter Max kW	**N/A**	**$5.75 per kW**
All Seasons kW	**$6.30 per kW**	
PL-TOU SL-5	**Proposed**	**Current**
Customer Charge		
	$85.00	**$75.00**
kWh Charge		
All Seasons kWh	**N/A**	**0.597¢ per kWh**
On-Peak kWh	**9.10¢ per kWh**	**N/A**
Off-Peak kWh	**1.20¢ per kWh**	**N/A**
Winter kWh	**1.20¢ per kWh**	**N/A**
kW Charge		
Summer On-Peak kW	**N/A**	**$9.50 per kW**
Summer Max kW	**N/A**	**$2.15 per kW**
Winter Max kW	**N/A**	**$6.00 per kW**
All Seasons kW	**$6.30 per kW**	

Q. **What are the impacts to these customer classes under the proposed tariffs?**

A. The class impacts and unit cost analysis results are contained within Exhibit GWT-2.

Municipal Lighting ("LM") and Outdoor Security Lighting ("OSL") Rate Design

Q. **How did OG&E design the prices for the lighting classes?**

A. The rate design was based on the current fixture, pole and underground wiring costs. In order to derive the price changes, the current tariff prices were compared to the current costs. OG&E then decreased fixture costs in order to recover the reduced revenue requirement for these classes. The prices for similar fixtures under LM (100% Company owned) and OSL continue to be the same. Schedule H-2 contains the rate change impacts. No installed fixture or pole price was increased. Costs for underground wiring, the break-away base and customer-owned LM fixtures were adjusted according to cost. The proposed prices for LM and OSL are shown in the proposed tariffs and in Schedule H-2 filed in this docket.

Q. **Did the Company add or remove any fixtures from the tariffs?**

A. Yes. The Company added two new decorative fixtures to both tariffs. Pricing for the new fixtures was established based on current costs. We have also removed several fixtures which are no longer offered and are not currently installed on the Company's system.

Cogeneration and Net Metering

Q. **Are there any changes proposed to the small power producer purchase schedules?**

A. Yes. There are small changes to the Net Metering for 300 KW or Below ("NET-1") tariff and the Standard Rate Schedule for Cogeneration and Small Power Production of 100 KW or Less ("COG-1") tariff. The current NET-1 tariff is available to residential customers that are 25 kW or less and to commercial and industrial customers that have generating facilities of 300 kW or less. These NET-1 customers generally take service under the R-1, GS-1, PL-1, PL-TOU, R-TOU, GS-TOU, and PM-1 standard rate schedules. The Company is proposing that the few NET-1 customers on this rate be required to take service under only R-TOU, CS-TOU, PL-TOU, R-VPP, and GS-VPP.

Q. **Why is this change warranted?**

A. Requiring these few NET-1 customers to subscribe to time differentiated rate options will align the credits these small producers receive for their output with the Company's production costs.

Q. **Are there other changes to the NET-1 tariff?**

A. Yes. In light of the recent FERC ruling overturning the California provision of paying net metering customers more than a utility's avoided cost,[2] OG&E removed the banking provision of the existing tariff. Allowing a customer to bank energy will result in customers being able to take advantage of the difference between peak and off-peak prices and, therefore, be paid in excess of OG&E's avoided costs. By compensating the NET-1 customer in the month in which they generate the kWh, the Company removes most subsidy to or subsidy from all other customers on the system.

Q. **Have any NET-1 customers banked kWh?**

A. Yes. One NET-1 customer banked 30 kWh, but for only one month.

Q. **What changes are being proposed to the COG-1 tariff?**

A. The "PURCHASE RATE" section in the COG-1 tariff was modified to adopt the TOU Energy Cost Recovery ("TOU ECR") factors. The on-peak period purchase rate reflects the net present value ("NPV") of future capacity costs spread over 430 hours. This results in an on-peak purchase rate of $0.208 per kWh. This action aligns the rate to reflect the Company's current avoided costs.

Rider Additions and Modifications

Q. **Is OG&E proposing modifications to any existing riders?**

A. Yes. The ECR and the Storm Damage Recovery ("SDR") riders are being modified. The details of and reasons for the ECR changes are explained in Mr. Rowlett's direct testimony. Similarly, the details of and reasons for the SDR changes are explained in Ms. Richard's direct testimony.

Q. **Are any new riders presented for approval within this Docket?**

A. Yes. OG&E is proposing two new riders. The SPP Cost Recovery ("SPPCR") rider and the Customer Education and Demand Response ("CEDR") rider have been included in

[2] *See California Public Utilities Commission, et al.*, 132 FERC ¶ 61,047 (2010).

the proposed tariffs within this docket. Approval of the SPPCR rider is sponsored by Mr. Rowlett and the CEDR rider is sponsored by Mr. Scott.

Q. **How will the SPPCR distribute costs and collect revenues from OG&E customers?**

A. The SPPCR allocates credits and costs to customers, based on service level, using the approved transmission allocator and recover these costs through an energy charge to all customers.

Q. **How will the CEDR rider allocate and collect or credit the associated expenses or revenues?**

A. Costs and credits associated with this rider are allocated to customers through an energy allocator and assessed to customers as a charge for each kWh consumed.

Q. **Does this conclude your direct testimony?**

A. Yes.

Residential - Service Level 5

Unit Cost Components			
Total Customer Component	$ 5,857,619	PD (Peak Component)	$ 6,121,336
		PD (Avg Component)	$ 5,294,722
Total Energy Component	$ 3,486,113	Trans Demand	$ 4,550,507
		Dist Demand	$ 10,388,285
Total of All Compnents	$ 35,698,582	Total Demand Component	$ 26,354,850

Customer Charge	Annual Billing Units	Miscellaneous Revenue	Customer	Dist Demand	Cust and Dist Less Miscellaneous	Unit Cost Price
	651,648	$ 467,363	$ 5,857,619	$ 10,388,285	$ 15,778,541	$ 24.21

Energy Charge	Proforma Billing Units	Energy	PD (Peak Component)*	PD (Avg Component)	Transmission Demand	Distribution Demand	Energy and Demand Total Revenue Req From Unit Cost		Unit Cost Price
Summer								Summer	
First 1400 KWH	268,428,650	$ 1,278,933	$ 2,535,995	$ 1,942,449	$ 1,669,422		$ 7,426,799	First 1400 KWH	$ 0.027668
Over 1,400 KWH	63,472,162	$ 302,414	$ 3,585,341	$ 459,308	$ 394,749		$ 4,741,812	Over 1,400 KWH	$ 0.074707
Winter kWh								Winter kWh	
First 600 KWH	202,536,747	$ 964,990		$ 1,465,631	$ 1,259,625		$ 3,690,245	First 600 KWH	$ 0.018220
Over 600 KWH	197,244,603	$ 939,775		$ 1,427,335	$ 1,226,711		$ 3,593,822	Over 600 KWH	$ 0.018220
Total Energy	731,682,162	$ 3,486,113	$ 6,121,336	$ 5,294,722	$ 4,550,507	$ -	$ 19,452,678		
Check		$ 3,486,113	$ 6,121,336	$ 5,294,722	$ 4,550,507		$ 19,452,678		
Difference		$ -	$ -	$ -	$ -	$ -	$ -		

General Service - Service Level 3

Unit Cost Components			
Total Customer Component	$ 9,296	PD (Peak Component)	$ 1,628
		PD (Avg Component)	$ 3,906
Total Energy Component	$ 2,574	Trans Demand	$ 2,324
		Dist Demand	$ 6,689
Total of All Components	$ 26,416	Total Demand Component	$ 14,546

Customer Charge	Annual Billing Units	Miscellaneous Revenue	Customer Component	Dist Demand	Cust and Dist Less Miscellaneous	Unit Cost Price
	108	$ 71	$ 9,296	$ 6,689	$ 15,914	$ 147.35

Energy Charge		Energy	PD (Peak Component)	PD (Avg Component)	Transmission Demand	Distribution Demand	Energy and Demand Total Revenue Req From Unit Cost	Summer	Unit Cost Price
Summer									
All KWH	183,005	$ 847	$ 1,628	$ 1,285	$ 764		$ 4,524	**All KWH**	$ 0.0247
Winter kWh								**Winter kWh**	
First 1,000 KWH	57,365	$ 265		$ 403	$ 240		$ 908	**First 1,000 KWH**	$ 0.0158
Over 1,000 KWH	315,860	$ 1,461		$ 2,218	$ 1,319		$ 4,999	**Over 1,000 KWH**	$ 0.0158
Total Energy	556,230	$ 2,574	$ 1,628	$ 3,906	$ 2,324	$ -	$ 10,431		
Check		$ 2,574	$ 1,628	$ 3,906	$ 2,324		$ 10,431		
Difference		$ -	$ -	$ -	$ -	$ -	$ -		

General Service - Service Level 5

Unit Cost Components			
Total Customer Component	$ 1,235,671	PD (Peak Component)	$ 1,806,602
		PD (Avg Component)	$ 1,543,555
Total Energy Component	$ 1,016,377	Trans Demand	$ 1,338,811
		Dist Demand	$ 3,542,583
Total of All Components	$ 10,483,599	Total Demand Component	$ 8,231,551

Customer Charge	Annual Billing Units	Miscellaneous Revenue	Customer Component	Dist Demand	Cust and Dist Less Miscellaneous	Unit Cost Price
	111,276	$ 76,235	$ 1,235,671	$ 3,542,583	$ 4,702,019	$ 42.26

Energy Charge		Energy	PD (Peak Component)	PD (Avg Component)	Transmission Demand	Distribution Demand	Energy and Demand Total Revenue Req From Unit Cost	Summer	Unit Cost Price
Summer									
All KWH	101,915,806	$ 485,722	$ 1,806,602	$ 737,658	$ 639,812		$ 3,669,794	**All KWH**	$ 0.0360
Winter kWh								**Winter kWh**	
First 1,000 KWH	41,372,198	$ 197,176		$ 299,449	$ 259,728		$ 756,353	**First 1,000 KWH**	$ 0.0183
Over 1,000 KWH	69,971,557	$ 333,478		$ 506,448	$ 439,271		$ 1,279,198	**Over 1,000 KWH**	$ 0.0183
Total Energy	213,259,561	$ 1,016,377	$ 1,806,602	$ 1,543,555	$ 1,338,811	$ -	$ 5,705,345		
Check		$ 1,016,377	$ 1,806,602	$ 1,543,555	$ 1,338,811		$ 5,705,345		
Difference		$ -	$ -	$ -	$ -	$ -	$ -		

Power and Light - Service Level 2

Unit Cost Compoents			
Total Customer Component	$ 20,053	PD (Peak Component)	$ 138,747
		PD (Avg Component)	$ 228,737
Total Energy Component	$ 150,628	Trans Demand	$ 133,394
		Dist Demand	$ 7,808
Total of All Components	$ 679,368	Total Demand Component	$ 508,686

Customer Charge	Annual Billing Units	Miscellaneous Revenue	Customer Component	Customer Less Misc	Calculated New Price
	12	$ 511	$ 20,053	$ 19,542	$ 1,628.53

Energy Charge		Energy	PD (Peak Component)	PD (Avg Component)	Transmission Demand	Distribution Demand	Energy and Demand Total Revenue Req From Unit Cost	Summer	Calculated New Price
All kWh	33,593,768	$ 150,628		$ 228,737			$ 379,366	All kWh	$ 0.01129
Demand Charge								Demand Charge	
Summer kW	25,380		$ 138,747	$ -	$ 60,518	$ 3,542	$ 202,807	Summer kW	$ 7.99
Winter kW	30,563			$ -	$ 72,876	$ 4,266	$ 77,142	Winter kW	$ 2.52
Total kW	55,943	$ 150,628	$ 138,747	$ 228,737	$ 133,394	$ 7,808	$ 659,315		
		$ 150,628	$ 138,747	$ 228,737	$ 133,394	$ 7,808	$ 659,315		
		$ -	$ -	$ -	$ -	$ -	$ -		

Power and Light - Service Level 3

Unit Cost Compoents			
Total Customer Component	$ 179,632	PD (Peak Component)	$ 1,069,225
		PD (Avg Component)	$ 1,498,287
Total Energy Component	$ 985,379	Trans Demand	$ 945,036
		Dist Demand	$ 1,701,111
Total of All Components	$ 6,378,670	Total Demand Component	$ 5,213,659

Customer Charge	Annual Billing Units	Miscellaneous Revenue	Customer Component	Customer Less Misc	Calculated New Price
	336	$ 4,379	$ 179,632	$ 175,252	$ 521.58

Energy Charge		Energy	PD (Peak Component)	PD (Avg Component)	Transmission Demand	Distribution Demand	Energy and Demand Total Revenue Req From Unit Cost	Summer	Calculated New Price
All kWh	216,663,648	$ 985,379		$ 1,498,287			$ 2,483,666	All kWh	$ 0.01146
Demand Charge								Demand Charge	
Summer kW	211,252		$ 1,069,225	$ -	$ 425,989	$ 766,800	$ 2,262,013	Summer kW	$ 10.71
Winter kW	257,401			$ -	$ 519,048	$ 934,311	$ 1,453,359	Winter kW	$ 5.65
Total kW	468,653	$ 985,379	$ 1,069,225	$ 1,498,287	$ 945,036	$ 1,701,111	$ 6,199,038		
		$ 985,379	$ 1,069,225	$ 1,498,287	$ 945,036	$ 1,701,111	$ 6,199,038		
		$ -	$ -	$ -	$ -	$ -	$ -		

Power and Light - Service Level 4

Unit Cost Compoents			
Total Customer Component	$ 2,511	PD (Peak Component)	$ 7,548
		PD (Avg Component)	$ 1,641
Total Energy Component	$ 1,018	Trans Demand	$ 1,471
		Dist Demand	$ 36,116
Total of All Components	$ 50,305	Total Demand Component	$ 46,776

Customer Charge	Annual Billing Units	Miscellaneous Revenue	Customer Component	Customer Less Misc	Calculated New Price
	12	$ 56	$ 2,511	$ 2,455	$ 204.62

Energy Charge		Energy	PD (Peak Component)	PD (Avg Component)	Transmission Demand	Distribution Demand	Energy and Demand Total Revenue Req From Unit Cost	Summer	Calculated New Price
All kWh	228,800	$ 1,018		$ 1,641			$ 2,659	All kWh	$ 0.01162
Demand Charge								Demand Charge	
Summer kW	2,876		$ 7,548	$ -	$ 682	$ 16,750	$ 24,981	Summer kW	$ 8.69
Winter kW	3,325			$ -	$ 789	$ 19,365	$ 20,154	Winter kW	$ 6.06
Total kW	6,201	$ 1,018	$ 7,548	$ 1,641	$ 1,471	$ 36,116	$ 47,793		
		$ 1,018	$ 7,548	$ 1,641	$ 1,471	$ 36,116	$ 47,793		
		$ -	$ -	$ -	$ -	$ -	$ -		

Power and Light - Service Level 5

Unit Cost Compoents			
Total Customer Component	$ 957,960	PD (Peak Component)	$ 2,871,006
		PD (Avg Component)	$ 3,444,353
Total Energy Component	$ 2,267,969	Trans Demand	$ 2,561,914
		Dist Demand	$ 5,890,392
Total of All Components	$ 17,993,592	Total Demand Component	$ 14,767,664

Customer Charge	Annual Billing Units	Miscellaneous Revenue	Customer Component	Customer Less Misc	Calculated New Price
	10,692	$ 19,680	$ 957,960	$ 938,279	$ 87.76

Energy Charge		Energy	PD (Peak Component)	PD (Avg Component)	Transmission Demand	Distribution Demand	Energy and Demand Total Revenue Req From Unit Cost	Summer	Calculated New Price
All kWh	475,779,311	$ 2,267,969		$ 3,444,353			$ 5,712,322	All kWh	$ 0.01201
Demand Charge								Demand Charge	
Summer kW	649,770		$ 2,871,006	$ -	$ 1,145,894	$ 2,634,656	$ 6,651,556	Summer kW	$ 10.24
Winter kW	802,943			$ -	$ 1,416,020	$ 3,255,735	$ 4,671,755	Winter kW	$ 5.82
Total kW	1,452,713	$ 2,267,969	$ 2,871,006	$ 3,444,353	$ 2,561,914	$ 5,890,392	$ 17,035,633		
		$ 2,267,969	$ 2,871,006	$ 3,444,353	$ 2,561,914	$ 5,890,392	$ 17,035,633		
		$ -	$ -	$ -	$ -	$ -	$ -		

Power and Light Time of Use - Service Level 1

Unit Cost Components			
Total Customer Component	$ 255,319	PD (Peak Component)	$ 1,591,721
		PD (Avg Component)	$ 3,076,342
Total Energy Component	$ 2,025,567	Trans Demand	$ 1,880,899
		Dist Demand	$ 0
Total of All Components	$ 8,829,849	Total Demand Component	$ 6,548,962

Customer Charge	Annual Billing Units	Miscellaneous Revenue	Customer Component	Rev Req Less Miscellaneous	Calculated New Price
	24	$ 6,925	$ 255,319	$ 248,395	$ 10,349.78

Energy Charge		Energy	PD (Peak Component)	PD (Avg Component)	Transmission Demand	Distribution Demand	Energy and Demand Total Revenue Req From Unit Cost	Summer	Calculated New Price
Summer									
On-Peak kWh	25,609,077	$ 113,760	$ 1,591,721	$ 172,774	$ -	$ -	$ 1,878,255	On-Peak kWh	$ 0.07334
Off-Peak kWh	164,437,557	$ 730,461		$ 1,109,391	$ -	$ -	$ 1,839,852	Off-Peak kWh	$ 0.01119
Winter All kWh	265,938,694	$ 1,181,346		$ 1,794,177	$ -	$ -	$ 2,975,523	Winter All kWh	$ 0.01119
Total kWh	455,985,328								
Demand									
Max kW	1,048,280		$ -		$ 1,880,899	$ 0	$ 1,880,899	Max kW	$ 1.79
		$ 2,025,567	$ 1,591,721	$ 3,076,342	$ 1,880,899	$ 0	$ 8,574,529		
		$ 2,025,567	$ 1,591,721	$ 3,076,342	$ 1,880,899	$ 0	$ 8,574,529		
		$ -	$ -	$ -	$ -	$ -	$ -		

Power and Light Time of Use - Service Level 2

Unit Cost Components			
Total Customer Component	$ 98,467	PD (Peak Component)	$ 512,378
		PD (Avg Component)	$ 943,352
Total Energy Component	$ 621,571	Trans Demand	$ 511,156
		Dist Demand	$ 285,651
Total of All Components	$ 2,972,575	Total Demand Component	$ 2,252,537

Customer Charge	Annual Billing Units	Miscellaneous Revenue	Customer Component	Rev Req Less Miscellaneous	Calculated New Price
	36	$ 2,576	$ 98,467	$ 95,891	$ 2,663.63

Energy Charge		Energy	PD (Peak Component)	PD (Avg Component)	Transmission Demand	Distribution Demand	Energy and Demand Total Revenue Req From Unit Cost	Summer	Calculated New Price
Summer									
On-Peak kWh	7,264,980	$ 32,716	$ 512,378	$ 49,652	$ -		$ 594,746	On-Peak kWh	$ 0.08186
Off-Peak kWh	52,649,714	$ 237,093		$ 359,834	$ -		$ 596,926	Off-Peak kWh	$ 0.01134
Winter All kWh	78,113,571	$ 351,762		$ 533,866	$ -		$ 885,628	Winter All kWh	$ 0.01134
Total kWh	138,028,265								
Demand									
Max kW	324,104		$ -		$ 511,156	$ 285,651	$ 796,807	Max kW	$ 2.46
		$ 621,571	$ 512,378	$ 943,352	$ 511,156	$ 285,651	$ 2,874,108		
		$ 621,571	$ 512,378	$ 943,352	$ 511,156	$ 285,651	$ 2,874,108		
		$ -	$ -	$ -	$ -	$ -	$ -		

Power and Light Time of Use - Service Level 3

Unit Cost Components			
Total Customer Component	$ 276,128	PD (Peak Component)	$ 1,677,960
		PD (Avg Component)	$ 2,453,431
Total Energy Component	$ 1,613,811	Trans Demand	$ 1,513,278
		Dist Demand	$ 2,728,217
Total of All Components	$ 10,262,825	Total Demand Component	$ 8,372,886

Customer Charge	Annual Billing Units	Miscellaneous Revenue	Customer Component	Rev Req Less Miscellaneous	Calculated New Price
	312	$ 7,093	$ 276,128	$ 269,034	$ 862.29

Energy Charge		Energy	PD (Peak Component)	PD (Avg Component)	Transmission Demand	Distribution Demand	Energy and Demand Total Revenue Req From Unit Cost	Summer	Calculated New Price
Summer									
On-Peak kWh	22,140,970	$ 100,788	$ 1,677,960	$ 153,224	$ -		$ 1,931,972	On-Peak kWh	$ 0.08726
Off-Peak kWh	137,671,153	$ 626,691		$ 952,740	$ -		$ 1,579,430	Off-Peak kWh	$ 0.01147
Winter All kWh	194,709,298	$ 886,333		$ 1,347,467	$ -		$ 2,233,800	Winter All kWh	$ 0.01147
Total kWh	354,521,421								
Demand									
Max kW	824,558		$ -		$ 1,513,278	$ 2,728,217	$ 4,241,495	Max kW	$ 5.14
		$ 1,613,811	$ 1,677,960	$ 2,453,431	$ 1,513,278	$ 2,728,217	$ 9,986,697		
		$ 1,613,811	$ 1,677,960	$ 2,453,431	$ 1,513,278	$ 2,728,217	$ 9,986,697		
		$ -	$ -	$ -	$ -	$ -	$ -		

Power and Light Time of Use - Service Level 5

Unit Cost Components			
Total Customer Component	$ 132,744	PD (Peak Component)	$ 559,939
		PD (Avg Component)	$ 910,759
Total Energy Component	$ 599,529	Trans Demand	$ 550,917
		Dist Demand	$ 1,236,522
Total of All Components	$ 3,990,410	Total Demand Component	$ 3,258,137

Customer Charge	Annual Billing Units	Miscellaneous Revenue	Customer Component	Rev Req Less Miscellaneous	Calculated New Price
	624	$ 3,255	$ 132,744	$ 129,489	$ 207.51

Energy Charge		Energy	PD (Peak Component)	PD (Avg Component)	Transmission Demand	Distribution Demand	Energy and Demand Total Revenue Req From Unit Cost	Summer	Calculated New Price
Summer									
On-Peak kWh	7,987,784	$ 38,020	$ 559,939	$ 57,757	$ -		$ 655,716	On-Peak kWh	$ 0.08209
Off-Peak kWh	50,244,190	$ 239,150		$ 363,299	$ -		$ 602,449	Off-Peak kWh	$ 0.01199
Winter All kWh	67,725,904	$ 322,359		$ 489,703	$ -		$ 812,063	Winter All kWh	$ 0.01199
Total kWh	125,957,878								
Demand									
Max kW	284,695		$ -		$ 550,917	$ 1,236,522	$ 1,787,439	Max kW	$ 6.28
		$ 599,529	$ 559,939	$ 910,759	$ 550,917	$ 1,236,522	$ 3,857,667		
		$ 599,529	$ 559,939	$ 910,759	$ 550,917	$ 1,236,522	$ 3,857,667		
		$ -	$ -	$ -	$ -	$ -	$ -		

Chart 1. PL-TOU SL1 Impact Matrix.

Load Factor Matrix PL-TOU SL1											
PL-TOU SL1	1-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91+%	Total
Over 21,999 kW	0	0	0	0	0	1 $1,177,315 6.41%	0	0	0	0	1 $1,177,315 6.41%
20,000 to 21,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
18,000 to 19,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
16,000 to 17,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
14,000 to 15,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
12,000 to 13,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
10,000 to 11,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
8,000 to 9,999 kW	0	0	0	0	0	0	0	1 $254,375 9.76%	0	0	1 $254,375 9.76%
6,000 to 7,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
4,000 to 5,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
2,000 to 3,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
0 to 1,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
Totals	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	1 $1,177,315 6.41%	0 $0 0.00%	1 $254,375 9.76%	0 $0 0.00%	0 $0 0.00%	2 $1,431,690 6.83%

Chart 2. PL-TOU SL1 Unit Cost Analysis

Load Factor Matrix PL-TOU SL1 Unit											
PL-TOU SL1	1-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91+%	Total
Over 21,999 kW	0	0	0	0	0	1 $90,938 0.47%	0	0	0	0	1 $90,938 0.47%
20,000 to 21,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
18,000 to 19,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
16,000 to 17,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
14,000 to 15,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
12,000 to 13,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
10,000 to 11,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
8,000 to 9,999 kW	0	0	0	0	0	0	0	1 -$90,146 -3.05%	0	0	1 -$90,146 -3.05%
6,000 to 7,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
4,000 to 5,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
2,000 to 3,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
0 to 1,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
Totals	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	1 $90,938 0.47%	0 $0 0.00%	1 -$90,146 -3.05%	0 $0 0.00%	0 $0 0.00%	2 $792 0.00%

Chart 3. PL-TOU SL2 Impact Matrix

Load Factor Matrix PL-TOU SL2											
PL-TOU SL2	1-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91+%	Total
Over 10,999 kW	0	0	0	0	1 -$50,387 -1.50%	0	0	0	0	0	1 -$50,387 -1.50%
10,000 to 10,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
9,000 to 9,999 kW	0	0	0	0	0	0	0	1 $250,914 8.07%	0	0	1 $250,914 8.07%
8,000 to 8,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
7,000 to 7,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
6,000 to 6,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
5,000 to 5,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
4,000 to 4,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
3,000 to 3,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
2,000 to 2,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
1,000 to 1,999 kW	0	0	0	0	0	1 $24,040 5.12%	0	0	0	0	1 $24,040 5.12%
0 to 999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
Totals	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	1 -$50,387 -1.50%	1 $24,040 5.12%	0 $0 0.00%	1 $250,914 8.07%	0 $0 0.00%	0 $0 0.00%	3 $224,568 3.23%

Chart 4. PL-TOU SL2 Unit Cost Analysis Matrix

Load Factor Matrix PL-TOU SL2 Unit											
PL-TOU SL2	1-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91+%	Total
Over 10,999 kW	0	0	0	0	1 $19,045 0.58%	0	0	0	0	0	1 $19,045 0.58%
10,000 to 10,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
9,000 to 9,999 kW	0	0	0	0	0	0	0	1 $3,020 0.09%	0	0	1 $3,020 0.09%
8,000 to 8,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
7,000 to 7,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
6,000 to 6,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
5,000 to 5,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
4,000 to 4,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
3,000 to 3,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
2,000 to 2,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
1,000 to 1,999 kW	0	0	0	0	0	1 -$23,015 -4.46%	0	0	0	0	1 -$23,015 -4.46%
0 to 999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
Totals	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	1 $19,045 0.58%	1 -$23,015 -4.46%	0 $0 0.00%	1 $3,020 0.09%	0 $0 0.00%	0 $0 0.00%	3 -$950 -0.01%

Chart 5. PL-TOU SL3 Impact Matrix.

Load Factor Matrix PL-TOU SL3											
PL-TOU SL3	1-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91+%	Total
Over 10,999 kW	0	0	0	0	0	1 $348,475 10.67%	0	0	0	0	1 $348,475 10.67%
10,000 to 10,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
9,000 to 9,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
8,000 to 8,999 kW	0	0	0	0	0	0	1 $416,208 18.16%	0	0	0	1 $416,208 18.16%
7,000 to 7,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
6,000 to 6,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
5,000 to 5,999 kW	0	0	0	0	0	0	1 $278,650 18.22%	0	0	0	1 $278,650 18.22%
4,000 to 4,999 kW	0	0	0	0	1 $164,944 17.97%	1 $165,887 15.67%	1 $201,735 16.11%	0	0	0	3 $532,566 16.50%
3,000 to 3,999 kW	0	1 $37,835 12.73%	0	0	1 $133,037 18.15%	0	0	0	0	0	2 $170,872 16.58%
2,000 to 2,999 kW	0	0	0	0	1 $74,528 15.05%	2 $186,544 16.44%	1 $102,201 17.37%	0	0	0	4 $363,272 16.38%
1,000 to 1,999 kW	0	0	1 $36,456 16.78%	0	4 $209,738 16.90%	1 $79,386 15.81%	0	0	0	0	6 $325,580 16.61%
0 to 999 kW	0	1 $2,097 2.22%	0	1 $9,642 7.95%	1 $11,355 15.12%	1 $26,049 18.87%	0	0	0	0	4 $49,142 11.46%
Totals	0 $0 0.00%	2 $39,932 10.19%	1 $36,456 16.78%	1 $9,642 7.95%	8 $593,602 17.14%	6 $806,340 13.22%	4 $998,793 17.64%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	22 $2,484,765 15.58%

Chart 6. PL-TOU SL3 Unit Cost Analysis Matrix.

Load Factor Matrix PL-TOU SL3 Unit											
PL-TOU SL3	1-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91+%	Total
Over 10,999 kW	0	0	0	0	0	1 $25,344 0.71%	0	0	0	0	1 $25,344 0.71%
10,000 to 10,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
9,000 to 9,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
8,000 to 8,999 kW	0	0	0	0	0	0	1 $10,012 0.37%	0	0	0	1 $10,012 0.37%
7,000 to 7,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
6,000 to 6,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
5,000 to 5,999 kW	0	0	0	0	0	0	1 $4,183 0.23%	0	0	0	1 $4,183 0.23%
4,000 to 4,999 kW	0	0	0	0	1 $2,070 0.19%	1 $3,169 0.26%	1 $3,956 0.27%	0	0	0	3 $9,194 0.25%
3,000 to 3,999 kW	0	1 $1,360 0.41%	0	0	1 -$185 -0.02%	0	0	0	0	0	2 $1,175 0.10%
2,000 to 2,999 kW	0	0	0	0	1 -$2,015 -0.35%	2 -$3,211 -0.24%	1 -$2,079 -0.30%	0	0	0	4 -$7,305 -0.28%
1,000 to 1,999 kW	0	0	1 -$4,551 -1.76%	0	4 -$14,372 -0.98%	1 -$2,197 -0.38%	0	0	0	0	6 -$21,120 -0.92%
0 to 999 kW	0	1 -$4,645 -4.59%	0	1 -$4,950 -3.64%	1 -$5,918 -6.41%	1 -$5,706 -3.36%	0	0	0	0	4 -$21,219 -4.25%
Totals	0 $0 0.00%	2 -$3,285 -0.76%	1 -$4,551 -1.76%	1 -$4,950 -3.64%	8 -$20,420 -0.50%	6 $17,399 0.25%	4 $16,073 0.24%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	22 $265 0.00%

Chart 7. PL-TOU SL5 Impact Matrix.

Load Factor Matrix PL-TOU SL5											
PL-TOU SL5	1-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91+%	Total
Over 2,749 kW	0	0	0	0	0	0	2 $296,747 12.56%	0	0	0	2 $296,747 12.56%
2,500 to 2,749 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
2,250 to 2,499 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
2,000 to 2,249 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
1,750 to 1,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
1,500 to 1,749 kW	0	0	0	0	1 $56,062 13.71%	0	0	0	0	0	1 $56,062 13.71%
1,250 to 1,499 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
1,000 to 1,249 kW	0	0	0	0	0	1 $36,421 12.11%	1 $43,083 13.01%	1 $40,769 11.52%	0	0	3 $120,273 12.20%
750 to 999 kW	0	1 -$4,722 -4.03%	0	1 $9,997 4.49%	1 $27,542 12.79%	1 $32,824 11.79%	0	0	0	0	4 $65,641 7.87%
500 to 749 kW	0	0	1 $7,531 7.76%	1 $4,743 4.07%	0	1 $18,474 11.71%	0	0	0	0	3 $30,747 8.28%
250 to 499 kW	0	2 -$38 -0.04%	1 $4,119 6.83%	4 $24,750 7.66%	2 $29,313 11.76%	1 $14,504 12.24%	4 $60,275 12.42%	1 $16,295 12.52%	1 $16,619 12.59%	0	16 $165,836 10.34%
0 to 249 kW	0	2 -$1,312 -2.84%	3 $3,934 6.21%	5 $9,305 8.77%	6 $14,321 12.57%	2 $9,878 11.87%	1 $4,753 11.11%	0	0	0	19 $40,881 8.97%
Totals	0 $0 0.00%	5 -$6,072 -2.26%	5 $15,585 7.06%	11 $48,794 6.35%	10 $127,238 12.88%	6 $112,101 11.94%	8 $404,859 12.56%	2 $57,064 11.79%	1 $16,619 12.59%	0 $0 0.00%	48 $776,188 11.05%

Chart 8. PL-TOU SL5 Unit Cost Analysis Matrix.

Load Factor Matrix PL-TOU SL5 Unit											
PL-TOU SL5	1-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91+%	Total
Over 2,749 kW	0	0	0	0	0	0	2 $23,220 0.88%	0	0	0	2 $23,220 0.88%
2,500 to 2,749 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
2,250 to 2,499 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
2,000 to 2,249 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
1,750 to 1,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
1,500 to 1,749 kW	0	0	0	0	1 $4,079 0.88%	0	0	0	0	0	1 $4,079 0.88%
1,250 to 1,499 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
1,000 to 1,249 kW	0	0	0	0	0	1 $1,973 0.59%	1 $2,351 0.63%	1 $1,962 0.50%	0	0	3 $6,285 0.57%
750 to 999 kW	0	1 -$635 -0.56%	0	1 $425 0.18%	1 $1,288 0.53%	1 $1,748 0.56%	0	0	0	0	4 $2,826 0.32%
500 to 749 kW	0	0	1 -$193 -0.18%	1 -$509 -0.42%	0	1 $252 0.14%	0	0	0	0	3 -$450 -0.11%
250 to 499 kW	0	2 -$2,130 -1.99%	1 -$850 -1.30%	4 -$2,600 -0.74%	2 -$42 -0.02%	1 -$101 -0.08%	4 -$672 -0.12%	1 -$82 -0.06%	1 -$202 -0.14%	0	16 -$6,680 -0.38%
0 to 249 kW	0	2 -$2,595 -5.47%	3 -$3,828 -5.39%	5 -$6,275 -5.16%	6 -$7,366 -5.43%	2 -$1,986 -2.09%	1 -$1,038 -2.14%	0	0	0	19 -$23,087 -4.44%
Totals	0 $0 0.00%	5 -$5,360 -2.00%	5 -$4,872 -2.02%	11 -$8,958 -1.08%	10 -$2,041 -0.18%	6 $1,886 0.18%	8 $23,861 0.66%	2 $1,880 0.35%	1 -$202 -0.14%	0 $0 0.00%	48 $6,193 0.08%

Chart 9. PL SL2 Impact Matrix.

Load Factor Matrix PL-1 SL2											
PL-1 SL2	1-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91+%	Total
Over 10,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
10,000 to 10,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
9,000 to 9,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
8,000 to 8,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
7,000 to 7,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
6,000 to 6,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
5,000 to 5,999 kW	0	0	0	0	0	0	0	1 $128,444 8.19%	0	0	1 $128,444 8.19%
4,000 to 4,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
3,000 to 3,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
2,000 to 2,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
1,000 to 1,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
0 to 999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
Totals	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	1 $128,444 8.19%	0 $0 0.00%	0 $0 0.00%	1 $128,444 8.19%

Chart 10. PL SL2 Unit Cost Analysis Matrix.

Load Factor Matrix PL-1 SL2 Unit											
PL-1 SL2	1-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91+%	Total
Over 10,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
10,000 to 10,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
9,000 to 9,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
8,000 to 8,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
7,000 to 7,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
6,000 to 6,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
5,000 to 5,999 kW	0	0	0	0	0	0	0	1 -$852 -0.05%	0	0	1 -$852 -0.05%
4,000 to 4,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
3,000 to 3,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
2,000 to 2,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
1,000 to 1,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
0 to 999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
Totals	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	0 $0 0.00%	1 -$852 -0.05%	0 $0 0.00%	0 $0 0.00%	1 -$852 -0.05%

Chart 11. PL SL3 Impact Matrix.

Load Factor Matrix PL-1 SL3											
PL-1 SL34	1-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91+%	Total
Over 5,499 kW	0	0	0	0	1 $229,157 18.41%	0	1 $320,571 18.70%	0	0	0	2 $549,728 18.57%
5,000 to 5,499 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
4,500 to 4,999 kW	0	0	0	0	0	1 $217,756 18.74%	0	0	0	0	1 $217,756 18.74%
4,000 to 4,499 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
3,500 to 3,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
3,000 to 3,499 kW	0	0	0	0	0	0	1 $161,233 18.77%	0	0	0	1 $161,233 18.77%
2,500 to 2,999 kW	0	0	1 $81,799 18.83%	0	0	0	0	0	0	0	1 $81,799 18.83%
2,000 to 2,499 kW	0	0	0	0	0	0	1 $108,119 18.67%	0	0	0	1 $108,119 18.67%
1,500 to 1,999 kW	0	0	0	0	0	0	2 $191,730 18.62%	0	0	0	2 $191,730 18.62%
1,000 to 1,499 kW	0	0	0	1 $45,790 18.72%	0	0	0	1 $72,618 18.81%	0	0	2 $118,408 18.78%
500 to 999 kW	0	1 $16,314 18.95%	1 $20,522 19.08%	1 $34,196 18.29%	2 $57,938 18.77%	2 $74,502 19.01%	2 $87,982 18.77%	0	0	0	9 $291,454 18.81%
0 to 499 kW	0	0	1 $4,780 19.22%	3 $27,715 19.08%	3 $18,606 19.48%	0	0	0	0	0	7 $51,101 19.24%
Totals	0 $0 0.00%	1 $16,314 18.95%	3 $107,101 18.89%	5 $107,701 18.67%	6 $305,701 18.54%	3 $292,258 18.81%	7 $869,634 18.70%	1 $72,618 18.81%	0 $0 0.00%	0 $0 0.00%	26 $1,771,328 18.70%

Chart 12. PL SL3 Unit Cost Analysis Matrix.

Load Factor Matrix PL-1 SL3 Unit											
PL-1 SL34	1-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91+%	Total
Over 5,499 kW	0	0	0	0	1 $4,612 0.31%	0	1 $10,667 0.53%	0	0	0	2 $15,279 0.44%
5,000 to 5,499 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
4,500 to 4,999 kW	0	0	0	0	0	1 $4,651 0.34%	0	0	0	0	1 $4,651 0.34%
4,000 to 4,499 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
3,500 to 3,999 kW	0	0	0	0	0	0	0	0	0	0	0 $0 0.00%
3,000 to 3,499 kW	0	0	0	0	0	0	1 $3,982 0.39%	0	0	0	1 $3,982 0.39%
2,500 to 2,999 kW	0	0	1 -$3,834 -0.74%	0	0	0	0	0	0	0	1 -$3,834 -0.74%
2,000 to 2,499 kW	0	0	0	0	0	0	1 $1,799 0.26%	0	0	0	1 $1,799 0.26%
1,500 to 1,999 kW	0	0	0	0	0	0	2 $3,811 0.31%	0	0	0	2 $3,811 0.31%
1,000 to 1,499 kW	0	0	0	1 -$2,133 -0.73%	0	0	0	1 $985 0.22%	0	0	2 -$1,148 -0.15%
500 to 999 kW	0	1 -$3,613 -3.41%	1 -$2,958 -2.26%	1 -$1,438 -0.65%	2 -$4,139 -1.12%	2 -$3,347 -0.71%	2 -$1,361 -0.24%	0	0	0	9 -$16,854 -0.91%
0 to 499 kW	0	0	1 -$2,524 -7.84%	3 -$7,150 -3.97%	3 -$7,556 -6.21%	0	0	0	0	0	7 -$17,231 -5.16%
Totals	0 $0 0.00%	1 -$3,613 -3.41%	3 -$9,316 -1.36%	5 -$10,721 -1.54%	6 -$7,083 -0.36%	3 $1,304 0.07%	7 $18,897 0.34%	1 $985 0.22%	0 $0 0.00%	0 $0 0.00%	26 -$9,545 -0.08%

Chart 13. PL SL5 Impact Matrix.

Load Factor Matrix PL-1 SL5											
PL-1 SL5	1-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91+%	Total
Over 1,099 kW	0	1 $9,392 4.97%	0	1 $23,198 9.49%	0	1 $34,333 10.34%	0	0	1 $50,919 11.64%	0	4 $117,841 9.80%
1,000 to 1,099 kW	0	1 $4,609 3.89%	0	0	0	0	0	0	0	0	1 $4,609 3.89%
900 to 999 kW	0	0	0	1 $18,345 8.55%	1 $19,196 9.69%	0	0	0	0	0	2 $37,541 9.10%
800 to 899 kW	0	0	0	2 $30,520 8.53%	0	1 $23,014 10.31%	0	0	0	0	3 $53,534 9.21%
700 to 799 kW	0	0	2 $18,065 7.68%	0	0	2 $41,265 10.32%	1 $22,493 10.59%	0	0	0	5 $81,822 9.65%
600 to 699 kW	0	2 $8,642 5.24%	0	1 $11,463 9.16%	1 $13,764 9.69%	0	0	0	0	0	4 $33,870 7.84%
500 to 599 kW	0	1 $4,849 6.83%	5 $34,200 7.25%	3 $27,422 8.28%	5 $64,913 9.76%	3 $48,020 10.39%	0	0	0	0	17 $179,404 8.97%
400 to 499 kW	0	4 $13,886 5.96%	6 $33,256 7.43%	8 $64,609 9.21%	3 $32,431 9.67%	3 $38,841 10.64%	2 $28,675 10.94%	1 $18,520 11.62%	0	0	27 $230,218 9.19%
300 to 399 kW	3 $3,465 3.78%	6 $15,446 5.93%	2 $8,289 7.62%	9 $55,231 9.14%	10 $77,670 9.74%	2 $22,028 10.36%	0	0	0	0	32 $182,128 8.77%
200 to 299 kW	0	14 $28,459 6.32%	20 $59,027 7.67%	21 $96,618 9.11%	17 $97,738 9.67%	10 $72,152 10.55%	4 $31,719 10.75%	0	1 $9,236 11.47%	0	87 $394,949 9.08%
100 to 199 kW	2 $1,053 3.44%	52 $61,519 6.20%	79 $144,249 7.78%	63 $163,389 9.02%	39 $132,457 9.80%	27 $111,408 10.40%	21 $105,139 10.79%	4 $25,390 11.26%	0	0	287 $744,605 8.96%
0 to 99 kW	0	12 $10,777 6.91%	77 $85,153 8.10%	95 $117,393 9.02%	102 $157,150 9.85%	55 $90,569 10.38%	15 $26,717 10.90%	3 $6,600 11.29%	1 $1,959 11.66%	0	360 $496,318 9.37%
Totals	5 $4,518 3.69%	93 $157,579 5.98%	191 $382,238 7.74%	204 $608,188 9.01%	178 $595,321 9.77%	104 $481,630 10.42%	43 $214,744 10.79%	8 $50,511 11.39%	3 $62,113 11.62%	0 $0 0.00%	829 $2,556,841 9.09%

Chart 14. PL SL5 Unit Cost Analysis Matrix.

Load Factor Matrix PL-1 SL5 Unit											
PL-1 SL5	1-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91+%	Total
Over 1,099 kW	0	1 $976 0.49%	0	1 $266 0.10%	0	1 $194 0.05%	0	0	1 $462 0.09%	0	4 $1,898 0.14%
1,000 to 1,099 kW	0	1 $838 0.68%	0	0	0	0	0	0	0	0	1 $838 0.68%
900 to 999 kW	0	0	0	1 $359 0.15%	1 $239 0.11%	0	0	0	0	0	2 $598 0.13%
800 to 899 kW	0	0	0	2 $496 0.13%	0	1 $387 0.16%	0	0	0	0	3 $884 0.14%
700 to 799 kW	0	0	2 $642 0.25%	0	0	2 $228 0.05%	1 $378 0.16%	0	0	0	5 $1,249 0.13%
600 to 699 kW	0	2 $745 0.43%	0	1 $388 0.28%	1 $53 0.03%	0	0	0	0	0	4 $1,186 0.26%
500 to 599 kW	0	1 $425 0.56%	5 $1,258 0.25%	3 $750 0.21%	5 $730 0.10%	3 $626 0.12%	0	0	0	0	17 $3,790 0.17%
400 to 499 kW	0	4 $926 0.38%	6 $668 0.14%	8 $1,272 0.17%	3 $666 0.18%	3 $376 0.09%	2 $157 0.05%	1 $203 0.11%	0	0	27 $4,267 0.16%
300 to 399 kW	3 $14 0.01%	6 $638 0.23%	2 $218 0.19%	9 $650 0.10%	10 $649 0.07%	2 $383 0.16%	0	0	0	0	32 $2,552 0.11%
200 to 299 kW	0	14 $1,113 0.23%	20 $1,558 0.19%	21 $1,177 0.10%	17 $1,390 0.13%	10 $584 0.08%	4 $180 0.06%	0	1 $35 0.04%	0	87 $6,036 0.13%
100 to 199 kW	2 -$39 -0.12%	52 $1,202 0.11%	79 $2,182 0.11%	63 $1,156 0.06%	39 $672 0.05%	27 $368 0.03%	21 $414 0.04%	4 $125 0.05%	0	0	287 $6,080 0.07%
0 to 99 kW	0	12 $135 0.08%	77 -$356 -0.03%	95 -$1,088 -0.08%	102 -$1,137 -0.06%	55 -$847 -0.09%	15 -$226 -0.08%	3 -$39 -0.06%	1 -$20 -0.11%	0	360 -$3,578 -0.06%
Totals	5 -$25 -0.02%	93 $6,997 0.25%	191 $6,171 0.12%	204 $5,426 0.07%	178 $3,263 0.05%	104 $2,300 0.05%	43 $902 0.04%	8 $289 0.06%	3 $477 0.08%	0 $0 0.00%	829 $25,800 0.08%

ATTESTATION

I do hereby swear and affirm that the foregoing is my direct testimony in APSC Docket No. 10-067-U.

Gregory W. Tidwell

9/24/2010

Date