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Issue: Revenues; IEC; Rate Design; Rate Case Expense
Witness: Tim M. Rush
Type of Exhibit: Surrebuttal Testimony
Sponsoring Party: Kansas City Power & Light Company
Case No.: ER-2012-0174
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2012-0174

SURREBUTTAL TESTIMONY

OF

TIM M. RUSH

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
October 2012

"[redacted]**" Designates "Highly Confidential" Information Has Been Removed Pursuant To 4 CSR 240-2.135.**

SURREBUTTAL TESTIMONY

OF

TIM M. RUSH

Case No. ER-2012-0174

Q: Please state your name and business address.

A: My name is Tim M. Rush. My business address is 1200 Main Street, Kansas City, Missouri 64105.

Q: Are you the same Tim M. Rush who pre-filed Direct, Supplemental Direct and Rebuttal Testimony in this matter?

A: Yes, I am.

REVENUES

Q: Are you the witness for the Company responsible for revenues?

A: Yes. I presented testimony on the revenues of the Company.

Q: Have you reviewed the revenues utilized by Staff in their updated cost of service model?

A: Yes. I have reviewed the cost of service model and the associated schedules and have identified an issue with the revenues.

Q: Would you please describe the issue?

A: Yes. I have identified an issue with the treatment of a tie amount used to reconcile the test year revenues and sales amount used in the study with the revenue amount recorded in the General Ledger of the Company. The tie amount is used as a confirmation that the revenues developed from the unit sales rebilled at the historical rates in the test period closely approximate the recorded revenues in the test period. They have no unit sales

associated with the tie amount. During the year many adjustments may be made that could account for the difference between the rebilling of the unit sales in the test period and the recorded value used in the books and records. This could include bill adjustments from prior periods, prorations of customer bills, and meter errors. The Company has not used the tie amount in this or previous cases, regardless of its value, in the calculation of normalized revenues for ratemaking, because it is simply used as a confirmation that the rebilling process is accurate. Staff has been inconsistent with their treatment. Staff did not eliminate the tie to the General Ledger in the ER-2010-0355 case, understating normalized revenues $183,210. Staff eliminated the majority of the tie to the General Ledger in the ER-2009-0089 case when it was a negative ($4.3 million) by increasing normalized revenues by $4.2 million. In the current case Staff proposed to retain the tie amount of $1,082,466, overstating the revenues for the case. Again, no unit sales are associated with this adjustment, because all of the sales are accounted for in the rebilling process that both Staff and the Company use in the determination of revenues.

Q: Have you reviewed the issue with Staff?

A: Yes. On September 27th the Company held a meeting with representatives of Staff and reviewed the treatment of the tie amount, discussed the elements that are represented in the tie amount, and defined our position on the proper treatment of the tie amount. On October 2nd, after considering our position, Staff communicated their plan to retain the tie amount. Staff indicated their opinion that their historic treatment has been consistent and the revenues should be included.

Q: Do you agree with this position?

A: No. I believe this treatment provides an inaccurate representation of revenues.

Q: Please describe the elements that comprise the tie amount?

A: I must briefly describe the process used to prepare our billed revenues in order to explain the tie amount. At a high level, we use the actual data from our billing system to recreate the billing determinants and reproduce the revenues associated with the test year. Separately, revenues are recorded in the General Ledger of the Company. Because the amounts in the General Ledger include all billing related transactions including prorations, bill corrections, bill adjustments, and other non-billing amounts, the totals do not tie with the revenues reproduced through our revenue process. The tie amount can be positive or negative. The $1 million difference in this proceeding represents less than .14% of the total revenues in this case.

Q: Why should the tie amount be removed from the calculation of revenues?

A: It is the position of the Company that the revenues used in the rate proceeding should represent the normal revenues of the test period. Special efforts are made to correct the revenue amounts to properly reflect weather normalization, customer growth, and annualize rate increases occurring during the period. The amounts included in the General Ledger tie amount represent one time, non-normal, out of period transactions that result from the billing process. Including these amounts distorts the revenues. Staff has offered to adjust the amount if detailed support can be produced.

Q: Is it possible to quantify each element within the tie amount?

A: Only at a high level. In order to identify the detail of the tie amount it would require evaluating every bill issued by the Company and compile each deviation from the normal billing process.

Q: What is your recommendation concerning the revenue tie amount?

A: I recommend that the Commission accept the Company position and remove the tie amount from the calculation of normalized revenues. This will ensure that revenues are appropriate for ratemaking purposes.

RATE DESIGN

Q: Have you reviewed the Rebuttal Testimony provided by the parties in this case on both class cost of service ("CCOS") study and rate design?

A: Yes. I have reviewed the Rebuttal Testimony of Michael Scheperle on behalf of Staff, Maurice Brubaker on behalf of the Industrials, Dr. Dennis Goins representing the U.S. Department of Energy ("DOE"), Donald Johnstone representing the Midwest Energy Users' Association, and F. Jay Cummings representing Southern Union Company, d/b/a Missouri Gas Energy ("MGE").

Michael S. Scheperle Rebuttal

Q: Would you summarize Mr. Scheperle's rate design Rebuttal?

A: Mr. Scheperle summarizes the various CCOS study results and reinforces his opinion concerning the benefits of Staff's study. Mr. Scheperle then walks through the rate design proposals offered by the parties and provides comments on each.

Mr. Sheperle brings out some very important points on page 2 of his Rebuttal Testimony that is sometimes overlooked by other parties and should be emphasized in making any changes to the rate design that currently exists. He expresses the following points:

1.) A CCOS study is not precise and should only be used as a guide for design rates.

2.) Bill impacts, revenue stability, rate stability and public acceptance need to be considered.

Q: **Do you agree with his points to be considered in evaluating a CCOS and recommending the appropriate rate design in this proceeding.**

A: I agree that a CCOS study should only be used as a guide and that bill impacts, revenue stability, rate stability and public acceptance must be considered.

Q: **Do you believe that Mr. Scheperle followed those principles?**

A: To a certain extent, he did. However, on some of his recommendations, he did not follow them.

Q: **Would you elaborate?**

A: Yes. On page 6 of his Rebuttal Testimony, Mr. Scheperle states beginning with the question on line 8:

> **Q: Does Staff agree with MGE's rate design recommendation?**
>
> A: No. MGE's rate design recommendation is that the Commission eliminate KCPL's discounted (Cummings Direct Testimony, p.2) residential electric rates. Specifically, Rate B – Residential General Use and Space Heat – One Meter; Rate C – Residential General Use and Space Heat – 2 Meters; and Rate D (applicable to electric space and water heating). At this time, Staff does not support MGE's recommendation to eliminate the residential rate schedules mentioned above. Staff does not oppose all-electric residential rates but recommends that customers on such rate schedule(s) be moved toward KCPL's cost to serve them.

There are three points that I want to bring out of this Q&A.

1.) First, like with Mr. Scheperle I do not support the position of MGE proposed rate design. I previously responded to the MGE proposal in my Rebuttal Testimony. As I pointed out, no study or support was presented by MGE in its proposal. Nowhere has MGE taken into consideration the overall impacts on customers to its proposal.

2.) Second, I agree with Mr. Scheperle when he states that Staff is not opposed to all-electric residential rates. As I previously testified in my Rebuttal, all-electric, or space heating rates are well recognized in the industry. Staff, Company and DOE all presented CCOS for the All Electric class. The results are shown on page 3, Table 1 of Mr. Scheperle's Rebuttal Testimony. The All Electric class has a different usage profile than non-electric heating electric customers. Both the Staff and DOE CCOS results show that the residential All Electric class contributes a higher return than the residential non-electric heating class.

3.) Third, Mr. Scheperle's recommends that the space heating class should move toward KCPL's cost of service. I do not agree that Staff is following its own recommendation. As I pointed out above, both the Staff and DOE CCOS results show that the residential All Electric class has a higher return than the residential non-heating class. As such, Mr. Scheperle's recommendation to increase the space heating rates higher than the non-space heating rates is inconsistent with the results of his own study, as well as the study by DOE. Both studies show the All Electric class is contributing a return higher than the class average. Neither Staff nor DOE presented a seasonal CCOS.

Below is a summary of the results for the Residential class from the studies presented by the parties. The numbers reflect the index to the overall average. For example, for KCP&L Residential, .98 means that the return on investment is 98% of the overall return for the Company. For Staff, its CCOS would show the Residential class

provides a return of 53% of the overall system return for the Company. DOE would show 49% average return. Within the Residential class are 4 subcategories that Mr. Scheperle identified, Regular, All-Electric, Separately Metered and Time of Day. For the Staff CCOS, the Residential Regular contributes 54% of the average return, which is very near the overall Residential class return. The All-Electric class actually contributes a slightly higher return of 57% of the average. A similar story can be seen by looking at the DOE study. This is one of the reasons why I disagree with Staff's recommendation to increase the All-Electric class greater than the Regular class.

The other point I would make is that all three studies that are differentiated by the four classes within the Residential class demonstrate that the All-Electric class is justified. While it may have lower prices than the Regular class in the winter, its contribution to the return on investment demonstrates that the lower rates are justified.

Customer class	KCP&L	Staff	DOE	A&E 4NCP	A&E 2NCP	4DP
RESIDENTIAL	.98	.53	.49	.42	.42	.49
Regular	1.08	.54	.48			
All Electric	.75	.57	.50			
Separately Metered	.53	.24	.52			
Time of Day	.91	.90	.38			

Q: Do you have any other concerns you wish to address with regard to Mr. Scheperle's Rebuttal Testimony regarding the residential rate design recommendations?

A: Yes. Neither Mr. Scheperle nor Mr. Cummings with MGE have shown the impacts on customers that their recommendation will have. Below is a table that demonstrates the increases that customers would see under both the Staff and MGE proposals. As Mr. Scheperle pointed out customer impacts, revenue stability, rate stability and public

acceptance are critical issues that should be addressed in any rate design. As you can see, the overall impact to the residential All Electric rate is substantial to the customers.

	Bill Impact*		
All Electric Rate	**High**	**Typical****	**Low**
Staff Proposal			
Residential - One Meter	2.87%	1.36%	0.54%
Residential - Two Meter	1.82%	1.10%	0.32%
Small General Service - Seconday	3.55%	2.30%	0.07%
Medium General Service - Secondary	3.20%	-	0.01%
Medium General Service - Primary	3.27%	-	0.01%
Large General Service - Seconday	2.85%	-	0.04%
Large General Service - Primary	3.04%	-	0.04%
MGE Proposal			
Residential - One Meter	18.92%	6.19%	2.62%
Residential - Two Meter	13.19%	10.48%	3.03%

* Bill impacts are calculated independent of any other approved revenue increase.

** Due to the varied usage characteristics of the Medium and Large customers, typical usage cannot be reasonably determined.

I have attached to my testimony as Schedule TMR-8 pages 1 through 9, a Bill Impact Analysis for customers who would be impacted by Mr. Scheperle's proposal. Mr. Scheperle is proposing to increase the residential space heating rate by 5% greater than the overall average residential rates for the winter period in the first rate block. This would have the impact of increasing the typical residential space heating customer by over 2.5% (about $4.25 per month in the winter time) more than the Company's proposed rate design.

I have a concern that increasing the rates paid by the All-Electric customers will have unintended consequences. Additionally, because the impact will most likely be highly publicized by MGE and others, it will most likely cause a significant stir by the residential customers with electric heat. It is likely that the Company will see customers

shift from electric heat to an alternative heating source. As a result, the Company will lose sales and ultimately lose margins, which means reduced earnings. Given the market conditions currently in place the Company will find it difficult to replace that loss of revenue and the Company may be forced into additional rate proceedings to address the loss.

Q: Do you have any comments in regard to Mr. Scheperle's Rebuttal Testimony regarding the non-residential rate design recommendation beyond those you addressed in Rebuttal?

A: I believe, again, Mr. Scheperle is proposing to increase the non-residential space heating customers without first evaluating the impact on those customers. The impacts on these customers must be understood. Additionally, the CCOS studies presented by Mr. Scheperle on page 3, Table 1 demonstrate that the non-residential All Electric customers all contribute a return on investment greater than the overall average.

Q: Do you have any further concerns with Mr. Scheperle's comments?

A: Yes. In my Rebuttal I expressed my concern with the Staff rate design in that it did not take into account the customer shifts that will almost assuredly result from Staff's proposal. Staff's proposal does not explore the disruption of the relationship between the Large General Service and the Large Power rate groups, leading to the potential rate switching impact of its proposal. Mr. Scheperle does not address my concern in his Rebuttal. In fact, in response to the Industrials' proposal, on page 19 of Mr. Scheperle's Rebuttal, he expresses the exact, rate switching concern I offer in respect to the Staff proposal. Rate switching is a very real risk to the Company and its ability to realize the authorized rate increase amount. Rate designs must consider or account for this

occurrence. I am also concerned with Staff's proposal to increase the Residential and General Service All-Electric rates.

Dr. Dennis W. Goins' Rebuttal

Q: Would you summarize Dr. Goins' rate design Rebuttal?

A: Dr. Goins' Rebuttal Testimony criticizes the CCOS studies offered by Staff and the revenue recommendation of Office of Public Counsel witness Barbara Meisenheimer. Concerning rate design issues, Dr. Goins continues to support across the board, equal application of any approved increase. His rate design proposal is consistent with the Company's position.

Donald Johnstone Rebuttal

Q: Would you summarize Mr. Johnstone's Rebuttal?

A: Mr. Johnstone's Rebuttal addresses CCOS studies offered in this case and discussed the space heating rate recommendations by the parties.

Q: Do you agree with his comments regarding space heating, starting on page 3 of his Rebuttal Testimony?

A: I do. I believe that the continued increases being imposed on the space heating customers greater than the average is and will cause problems with customers and ultimately cause further increases to the non-electric heating customers. As I presented in my Rebuttal Testimony, I believe that we need to look at CCOS as a guide, but it should not be the only contributing factor in setting rates. The one point I may disagree with Mr. Johnstone is that I did not suggest that the Base-Intermediate-Peak ("BIP") method was inappropriate or unreasonable for use in rate design, but I do believe that we need to look beyond that study at other issues and even other CCOS.

F. Jay Cummings Rebuttal

Q: Would you summarize Mr. Cummings' rate design Rebuttal?

A: Mr. Cummings' Rebuttal Testimony focuses on the rate design recommendations of Staff. Mr. Cummings continues to endorse his position concerning the elimination of the heating rates. Mr. Cummings responds to Staff's Direct Testimony by saying that Staff did not go far enough in its increase the rates to the residential space heating class.

Q: Do you agree with his conclusion?

A: No.

Q: Would you expand on that thought?

A: Yes. The current rate design for residential rates of KCP&L and most other electric companies use meters that are kwh meters and are based on averaging of both energy and demand costs into energy blocks. This is often why the rates are declining. For KCP&L, the incremental costs (i.e. energy) is less than 3 cents per kwh, the demand and any unrecovered customer costs are included in the remainder of the declining block energy rates. By contrast, the MGE rates are designed to include a customer charge and demand charge in the customer rate and include only energy in the energy rate. If KCP&L's rate design were based on this methodology, its rates would have a very high customer charge, around $74 per month and an energy rate of less than 2 cents per Kwh. While this may be correct pricing consistent with the rate design of MGE, it is not the current state of rate design we are at and I am not recommending this design. However, this may be a more appropriate rate than the rate being proposed by Mr. Cummings.

Q: Why doesn't the Company propose such a rate design?

A: The main reason is customer impact and what appears to be the standard for electric rate design across the country. Additionally, we believe that the proposed rate design by the Company is the appropriate design, without a full rate design/ CCOS study.

Q: Do you have any further concerns with Mr. Cummings' comments?

A: Mr. Cummings proposed rate changes are focused only on Residential rates and will result in considerable increases for customers in the Residential Space Heating -class. Additionally, the proposed rate changes do not take into account the Company's requested revenue requirement which would add to the impact.

As in our prior rate case MGE clearly has an ulterior motive - a direct economic incentive to prevent KCP&L from providing cost-based rates for customers who use electricity to heat their homes. Increasing the electric prices for new or existing customers who utilize electricity for space heating without any cost justification will likely result in less sales of electricity and more natural gas sales for MGE.

It is also important to note that outside of MGE, a natural gas company that provides service within KCP&L's service territory, there were no builders, developers or HVAC dealers that intervened in this rate case pursing rate design changes, in particular the elimination of all-electric rates. One would assume that if there was a large public outcry to eliminate certain rates that there may have been more interest in this case other than those with obvious self-interest, such as, the competing natural gas company.

Maurice Brubaker Rebuttal

Q: Would you summarize Mr. Brubaker's rate design Rebuttal?

A: Mr. Brubaker focuses his Rebuttal on discussion of the CCOS studies offered by Staff, OPC, and the Company and his concerns with the allocation methods employed. As his Rebuttal did not speak to rate design issues I do not have any comments in this Surrebuttal.

Q: Do you still support the position of Mr. Brubaker?

A: Yes. I support his analysis of the Large General Service and Large Power rates and his recommendation addressing the significance that the current rates place on energy and recommending that more of the rate design should reflect demand costs on the demand portion of the rates, than on the tail energy block.

Q: You have detailed your concerns with the respective rate design proposals. Do you stand by your original recommendation?

A: Yes. I recommend the increase be applied equally to all classes. Additionally, I recommend that the rate increase be applied to all of the rate components on an equal basis except for the Large General Service and Large Power rate classes. For those two classes, I support the recommendation of Missouri Industrial Energy Consumers and Midwest Energy Consumer's Group ("MIEC/MECG") witness Maurice Brubaker.

RENEWABLE ENERGY STANDARD ("RES")

Q: Does KCP&L disagree with Staff's statement that RES expense recovery should be based on costs through True-Up?

A: No. KCP&L agrees that the annual level of RES expense should be based on costs incurred, including carrying costs, through the true-up, August 31, 2012. However, an

annual level of expense should be reflective of a full twelve month annualized level of expense.

Q: Does KCP&L agree with Staff's statement that RES carrying costs be calculated using the Companies' short term debt rate.

A: Yes. The Commission's Order in Case No. EU-2012-0131 states that RES carrying costs should be based on the Companies' short term debt rate.

Q: Does Staff agree that a five-year amortization of deferred RES costs is an acceptable middle ground between Staff's three-year and MIEC/MECG's six-year amortizations?

A: No. Staff continues to support their three-year amortization[1] but still provides no rationalization for their position.

Q: Is Staff's unsupported amortization period acceptable to KCP&L?

A: No. KCP&L holds to the opinion that since there is no precise answer for the appropriate length for this amortization period, a five-year amortization is a reasonable middle ground compromise.

Q: What is Staff's position on earning a return on deferred expenses?

A: Staff believes that only capitalized costs should earn a return, as stated on pages 20-21 of Karen Lyons Rebuttal Testimony in this case:

> All the costs KCPL is requesting in its RES adjustment are expenses and not capital costs in nature. Consequently, KCPL should not be allowed to earn a return on these expenses above those already permitted by the Commission through carrying costs based on KCPL's short term debt rate.

[1] Karen Lyons, Rebuttal Testimony in Case No. ER-2012-0174, page 22.

Q: Did the Commission's Order in Case No. EU-2012-0131 address the appropriateness of deferring and capitalizing RES costs?

A: Yes. The Order, by granting the deferral of RES costs, has identified RES costs as capitalized per Missouri court ruling. Page 2 of the Order states:

> Missouri courts have recognized the Commission's regulatory authority to grant a form of relief to a utility in the form of an AAO "which allows the utility to defer and **capitalize** certain expenses until the time it files its next rate case." (Emphasis added).

Q: Why is it appropriate to include RES costs in rate base?

A: As stated in my Rebuttal Testimony in this case:

> The primary objective of Missouri's Renewable Energy Standard Law is to increase the use of renewable energy and thereby reduce future coal generation. Therefore, and particularly as it relates to solar renewable energy, the deferred RES costs are similar in nature to deferred DSM costs. Since both the Staff and the Company have consistently included deferred, unamortized DSM costs in rate base, KCP&L has included deferred RES costs in rate base in this case. Amortization will not begin until the effective date of new rates in this case; therefore, the entire deferral RES balance should be included in rate base.

LOW INCOME WEATHERIZATION

Q: Do you wish to respond to Staff and MDNR's recommendations regarding KCP&L's Low Income Weatherization (LIW) program?

A: Yes, I do. In particular, I wish to respond to Staff witness Henry Warren's four recommendations:

(1) That the Commission order KCP&L to carry over the unused funds from 2010, 2011, 2012 and all subsequent years;

(2) That such funds be made available solely for the KCP&L weatherization agencies for low income weatherization funding;

(3) That the Commission order KCP&L to provide monthly reports to the DSM Advisory Group on low income weatherization funding and expenditures and submit the reports as non-case-related submissions in EFIS; and

(4) That as long as KCP&L's low-income weatherization program is funded in rates, the program should not be included in any subsequent filing under the Missouri Energy Efficiency Investment Act ("MEEIA").

First, I will respond to the rolling over of funds. The LIW program was born from the Comprehensive Energy Plan ("CEP"), a five-year plan which has reached completion. The LIW plan was part of the other energy efficiency programs and had special accounting treatment established in the CEP for all programs. Tariffs were established for each of the energy efficient programs, including the LIW program. Program costs were deferred until the following rate case, at which time they were amortized over a specified period. Mr. Warren suggests that KCP&L requires a tariff change to be in compliance with the carry-over language suggested by Mr. Warren. I disagree with Mr. Warren's recommendations 1 and 2. The tariff language states:

> To the extent the funds set forth in Appendix C for the Low-Income Weatherization Program exceeds the total cost expended on the Program, the amount of excess shall be "rolled over" to be utilized for the Weatherization Program in the succeeding year. **After five years from the effective date of the Low-Income Weatherization Program, if there is excess funding the amount shall be available for other Affordability programs.** (Emphasis added).

The LIW program tariff was first approved on December 1, 2005. The five year roll-over time frame has been reached. As discussed in my Rebuttal Testimony, if a weatherization agency depletes its annual allocation of weatherization funding and requests additional funding, KCP&L would discuss the request with the DSM Advisory Group and work within the DSM Advisory Group to provide additional funding.

Q: Are there any funds that have been collected in rates that have been unused?

A: No. Currently, KCP&L places into a deferred regulatory asset only those funds that have actually been expended. These deferred costs are being recovered in rates over a period of time authorized by the Commission. There are no amounts included in rates other than the amortization of these previously deferred costs.

Q: Please continue.

A: I also wish to respond to Staff's recommendation that the Commission should order KCP&L to provide monthly reports to the DSM Advisory Group on low income weatherization funding and expenditures and submit the reports as non-case-related submissions in EFIS. KCP&L currently meets with the DSM Advisory Group on a quarterly basis and provides program updates. KCP&L believes this is the appropriate timeframe and does not see a necessity in creating additional reporting requirements for the LIW program.

Finally, I wish to address Staff's recommendation that as long as the LIW program is funded in rates, it should not be included in any KCP&L MEEIA filing. The LIW program is part of KCP&L's DSM portfolio. There are no restrictions in the MEEIA rules regarding allowance of low-income programs in a company's DSM program plan. Therefore, KCP&L disagrees with Staff's recommendation.

INTERIM ENERGY CHARGE ("IEC")

Q: Do you agree with Staff's position taken regarding KCP&L's request for an IEC?

A: No, I do not.

Q: Please summarize the concerns raised in the Rebuttal Testimony of Staff Witnesses Lena Mantle and Cary Featherstone with which you disagree.

A: Staff raised the following concerns:

1) The proposal is not an IEC because it does not contain a defined floor or ceiling (Mantle Rebuttal at pages 7-9; Featherstone Rebuttal at pages 18-21, 23-25).

2) The proposal is not an IEC because it does not include a refundable fixed charge (Mantle Rebuttal at page 9; Featherstone Rebuttal at page 25).

3) The proposed IEC does not meet other requirements of the 2005 Regulatory Plan Stipulation and Agreement (Featherstone Rebuttal at pages 19-20, 39-44).

4) The Staff does not understand the proposed IEC or its proposed tariff, and is confused by the Company testimony and explanations (Mantle Rebuttal at pages 2-5).

5) The proposed IEC is unlike any previous IEC proposals made within the state. (Featherstone Rebuttal at pages 20-29).

6) No previous IEC approved by the Commission has had an Off-System Sales ("OSS") sharing mechanism (Featherstone Rebuttal at page 25).

7) The Company does not need an IEC (Featherstone Rebuttal at pages 31-32, 36; Mantle Rebuttal at pages 10-11)

Q: Is the request made by the Company for an IEC or a Fuel Adjustment Clause ("FAC")?

A: The request is definitely for an IEC, not an FAC. Mr. Featherstone explains quite well the differences between an IEC and an FAC on pages 23 and 24 of his Rebuttal Testimony. I'll summarize those differences below:

FAC – An FAC is a pass through of cost differences; it has an opportunity for review and a process to address improper cost recovery; it offers periodic rate changes between rate cases; for the current Missouri FACs only a percentage of costs are passed through the clause to the customer and none have a limitation on what increases are passed on to customers or the savings retained by shareholders.

IEC – A IEC is not a pass through of costs; costs are collected on an interim basis; the IEC has a base and ceiling; it is active for a defined period of time; an IEC has a provision for a prudency audit and true up review; the IEC is in and of itself an incentive for the company to keep costs below floor.

Q: Has the Company requested an IEC?

A: Yes, as I explained in my Rebuttal Testimony in this case, an FAC allows for rate changes between rate cases. The Company's IEC proposal does not. The Company's proposal establishes a base rate as all IECs have done in the past. Instead of setting a ceiling that is higher than the base rate, KCP&L has attempted to soften any rate increase to the customer by proposing a mechanism under which it will manage those expected increases as well as the potentially volatile changes in the OSS market by offsetting the two thus setting the ceiling at $0.0000/kWh. In addition, the Company is proposing a sharing mechanism for the outer reaches of OSS margins. Thus, as we look at the definition given by Mr. Featherstone in his Rebuttal Testimony and summarized above, the Company's proposed IEC is not a pass through of costs; the costs are collected at the base level plus a ceiling of $0.0000 on an interim basis; the IEC is active for a two year period; the proposed tariff provides for a review and a true-up, with a potential refund at the conclusion of the IEC period.

Q: Does the IEC requested include an amount subject to refund as well as a floor and a ceiling?

A: Yes. KCP&L responded to this issue in the filing of its "Opposition of KCP&L to Motion to Strike Pre-filed Testimony and Reject Tariffs Relating to Interim Energy Charge" where the Company explains its position relating to this argument. Additionally, KCP&L's ceiling in its proposal should be interpreted to recommend that the actual costs of variable fuel and purchased power (net of OSS margins) be the "ceiling." Looking at proposed Tariff Sheet No. 24A (contained in Schedule TMR-4 to Mr. Rush's Direct Testimony), base costs are set forth as element "B" in the formula and are defined as "Base Variable Fuel & Purchased Power Costs - On System." The ceiling on Tariff Sheet No. 24A would logically be element "FFPON," which is defined as "Variable Fuel & Purchased Power Costs - On System," as adjusted by OSS margins. They represent the actual costs that would be incurred during the two-year period of the IEC.

Q: Does the IEC, as proposed by the Company include a floor amount?

A: Yes. The floor amount under the Company's proposal is again the actual costs of variable fuel and purchased power (net of OSS margins) is the "ceiling."

In addition, on page 13 of my Direct Testimony in this case I explain how the IEC mechanism would work and what would happen if either a negative or positive balance remained after the two-year IEC period. Specifically I said, "The proposed IEC would be established at zero price and remain at zero for two years. During that time, costs for variable fuel and purchased power costs to meet NSI would be accumulated in a deferred account. The base fuel for NSI established in this case would be an offset to this amount. Each amount would be set on an annual $ per kWh basis. For example, the base amount

for fuel and purchased power costs as proposed in the original filing by the Company is set in this case at $0.01596 per kWh. If during the first twelve-month period of the IEC the fuel and purchased power costs to meet NSI were $0.01696, then the deferred account would include an amount equal to that difference, i.e., $0.0010 times the NSI for the period. This amount would be offset by the OSS margin during the same twelve-month period, adjusted to reflect the sharing component of the IEC recommendation.

Q: Does the proposed IEC meet the other requirements of the regulatory plan?

A: Yes. The other items of the Regulatory Plan that Staff claimed were not met relate to OSS margins and the ability to make changes to rates outside of a rate case.

Q: On page 7 of Ms. Mantle's Rebuttal Testimony in this case she states that the IEC as proposed by the Company does not meet the requirements of the Regulatory Plan, specifically that the Company agreed that the rates or terms of the IEC cannot change outside a general rate case where all relevant factors are considered. She further points out that in my Direct Testimony, I state that given the uncertainty of how the implementation of the SPP Integrated Marketplace may change the structure of how costs are accounted for, the Company may need to adjust the IEC to account for these changes. Are these two statements in conflict?

A: No. The requirement under the Regulatory Plan identified by Ms. Mantle essentially separates an IEC from an FAC, meaning that the rates charged to the customer or the terms on which those rates are set cannot be changed outside of a rate case. The rate charged to the customer would remain the same throughout the two year period. The analysis of the comparison of actual costs to base costs might need to be adjusted to meet

the new market requirements. Any such adjustment would be made on a prospective basis only and only with the issue addressed before this Commission.

Q: On page 19 of Mr. Featherstone's Rebuttal Testimony he states, "...the 2005 Regulatory Plan obligates KCPL to include all off-system sales in the determination of its rates as long as its investment in Iatan 2 is included in KCPL's regulated rate base." Does KCP&L's IEC proposal meet this requirement?

A: Yes. The Stipulation from the Regulatory Plan requires that all revenue and expenses related to KCP&L's OSS "will continue to be used to establish Missouri jurisdictional rates as long as the related investments and expenses are considered in the determination of Missouri jurisdictional rates." See In re Proposed Regulatory Plan of Kansas City Power & Light Co., Case No. EO-2005-0329, Report and Order at 28-29 (July 28, 2005). The proposed IEC does take into consideration all revenue and expenses related to KCP&L's OSS in combination with the expenses associated with the fuel and purchased power required to provide service to its native load customers. In addition, the proposed sharing of OSS margins is consistent with the Staff's urging to find appropriate incentive mechanisms for KCP&L to increase its OSS margins. As I testified in my Direct Testimony, an Interim Energy Charge is expressly permitted under KCP&L's Regulatory Plan if it follows the parameters set forth in Section III(B)(1)(c) at pages 7-8 of the Stipulation. These six parameters do not prohibit a sharing mechanism. The proposed sharing does not exclude OSS from the ratemaking process. Instead, it proposes a way to share in the mitigation of risk both above and below the amount included in the rates established in the rate case. True to the language of the Stipulation, every penny of the OSS margins are being used to establish Missouri jurisdictional rates. While the sharing

mechanism recommended for the very upper and lower levels of OSS margin proposes that 25% of such amounts be retained by KCP&L, there is no language in the stipulation or in any Commission order that precludes it. This concept is consistent with the Commission's past statements that it would like to see more effective incentives for KCP&L to reach certain OSS margin levels.

Q: Ms. Mantle has stated in her Rebuttal Testimony beginning at page 2 that Staff cannot understand the proposed IEC mechanism as presented by the Company. How do you address her issues?

A: It is my opinion that one of the underlying issues with the Staff's problem is that the IEC mechanism proposed by the Company incorporates OSS margins of the Company. No IEC prior to this proposal included OSS margins. For the two utilities that previously had an IEC, Empire District Electric and Aquila, neither had OSS margins included in the IEC, nor did they have OSS margins at a level as significant as KCP&L. I believe the Staff's confusion stems from the fact that they had not previously dealt with OSS margins included in an IEC. Therefore, to Staff, this a relatively new concept, but it is clearly specified In re Proposed Regulatory Plan of Kansas City Power & Light Co., Case No. EO-2005-0329, Report and Order at 28-29, as well as the Electric Utility Fuel and Purchase Power Cost Recovery Mechanisms in 4 CSR240-20.090 (1)(F).

Q: On page 3 or Ms. Mantle's Rebuttal Testimony she states that my testimony makes no statement as to what would be done with a positive amount and that a negative amount might mean a refund to the customer. Do you agree with this assessment?

A: No. As I explained in my Direct Testimony on page 13, "The proposed IEC would be established at zero price and remain at zero for two years. During that time, costs for

variable fuel and purchased power costs to meet NSI would be accumulated in a deferred account. The base fuel for NSI established in this case would be an offset to this amount. Each amount would be set on an annual $ per kWh basis. For example, the base amount for fuel and purchased power costs is set in this case at $0.01596 per kWh. If during the first twelve-month period of the IEC the fuel and purchased power costs to meet NSI were $0.01696, then the deferred account would include an amount equal to that difference, i.e., $0.0010 times the NSI for the period. This amount would be offset by the OSS margin during the same twelve-month period, adjusted to reflect the sharing proposal described above.

This process would happen each year of the IEC's two-year period. At the end of the two years, if the amount in the deferred account were negative, then the Company would refund that amount to customers. If the amount were positive, then no refund would occur. A negative amount represents that the cost, net of OSS margins, for the two year period was below the base amount set in rates, adjusted for the sharing component of OSS margins, if any.

Q: On page 4 of Ms. Mantle's Rebuttal Testimony she states that it appears from the tariff sheet that between the 40th and 60th percentile the Company would "keep" all of the OSS margins. In the overall calculation as presented in the proposed tariff, is this correct?

A: No. This band of OSS margins would be offset against the amount of actual fuel and purchased power experienced during the same time frame. The net effect would be compared to the base fuel and purchased power costs on a kWh basis. The explanation of

a positive or negative balance given above would then apply to that net effect. The sharing ranges are a portion of the calculation, not the entirety.

Q: At page 4 of Ms. Mantle's Rebuttal Testimony, she states, "Mr. Rush's testimony is silent as to what happens if the off-system sales margin between the 40th and 60th percentile is greater than the difference between the actual and base fuel and purchased power costs." Is your testimony silent on this point?

A: No. Any refund would be determined by the change in fuel and purchased power costs along with the level of OSS margins attained. If the balance is positive, no refund would occur. If the balance is negative then a refund would be made. If the scenario that Ms. Mantle discusses in her testimony occurs, the balance would be negative and a refund would be made. The sharing mechanism relates to OSS margins and would only impact how much would be retained by the Company and how much would be refunded to the customer. Between the 40th and 60th percentiles KCP&L would absorb any OSS margin variance from base rates.

Q: On page 8 Ms. Mantle also states that the Company has not defined what will happen if it has not filed for another rate case after the end of the two-year IEC period. Is this true?

A: No, it is not. The proposed tariff sheet clearly states the following, "Any over collection will then be refunded with interest to customers following a review and true-up of variable fuel and purchased power costs at the conclusion of each IEC. Any uncontested amount of over-collection shall be refunded to ratepayers no later than 60 days following the filing of the IEC true-up recommendation of the Staff." At the end of the two year period, the IEC will cease and the Company will no longer operate under the IEC. Part

of the agreement in the Proposed Regulatory Plan was that an IEC could not exceed two years.

Q: Do you have a solution to the misunderstanding that Staff has relating to the IEC proposed tariff sheets?

A: Any time a new process is proposed in tariff form, there are bound to be questions. It has been my experience that the Company, the Commission Staff, and other interested parties work together to ensure that the final tariff provides enough information that those concerns are eliminated. I have provided examples of how the IEC would work to the parties involved in this case, have discussed the process with the Staff as well as with the other parties. The formula for the calculation of the "positive or negative" outcome is included in the tariff sheet. The Company is open to working with the parties on drafting tariff language that is more understandable and acceptable to those concerned. The proposed IEC, however, provides a mechanism where the Company can mitigate the risk of the uncertainty in the current OSS market while not charging an additional amount to its customers in the interim. This balancing of concerns should be considered a "win/win" situation that should be welcomed by the parties involved.

Q: Would the Company be willing to sit down with the Commission Staff as well as other interested parties to discuss the concerns over the specifics of this proposal.

A: Absolutely. I have presented examples in my Rebuttal Testimony in this case, and am willing to explain further how the costs related to various scenarios would flow through the formula included in the tariff.

Q: On page 9 of Ms. Mantle's Rebuttal Testimony, she quotes a portion of the Code of State Regulation's definition of an IEC and concludes that KCP&L's proposal does

not meet that definition because it does not contain a refundable fixed charge. How do you respond to this observation?

A: The proposed tariff contains several references to refunds and notes that "[a]ny over collection will be refunded with interest to customers ... at the conclusion of each IEC." See Rush Direct, Schedule TMR-4 at p. 1. I have also responded to Ms. Mantle's concerns above on page 24 with an explanation of how the IEC would work, including any refundable charge that is fixed.

Q: Mr. Featherstone spends a significant amount of time in his Rebuttal Testimony explaining that the IEC as proposed by KCP&L is not like any other that has been approved by the Commission, as well as explaining how those past IECs worked. Do you see this as a problem?

A: No. The Commission Rules 4 CSR 240-20.090(1)(F) and 4 CSR 240-3.161(1)(D) define an IEC to be "... a refundable fixed charge, established in a general rate proceeding, that permits an electric utility to recover some or all of its fuel and purchased power costs separate from its base rates. An IEC may or may not include OSS and revenues and associated costs. The commission shall determine whether or not to reflect OSS revenues and associated costs in an IEC in the general rate proceeding that establishes, continues or modifies the IEC." I find nothing in this definition that says all IECs must always be the same. As Mr. Featherstone points out in his Rebuttal Testimony, the prior IECs were developed by the parties to meet the needs of those individual companies and the customers they serve. The situation facing KCP&L is different from those cases because of the significance of OSS margin to the Company and, therefore, requires a different solution.

Q: On page 39 of Mr. Featherstone's Rebuttal Testimony he states, "This unique and unprecedented sharing approach to determining rates by removing or retaining a portion of off-system sales between certain ranges from the ratemaking process is contrary to the terms of the 2005 Regulatory Plan." How do you respond to this statement?

A: As noted above, I disagree with his interpretation of language in the Regulatory Plan relating to an IEC and OSS. However, I do agree that this proposal is a new and unique attempt to balance the needs of both the customer and the Company while dealing with a wholesale energy market that is unpredictable and volatile.

Q: On page 37 of his Rebuttal Testimony, Mr. Featherstone states that the regulatory treatment of OSS margins in KCP&L's revenue requirement was established based upon recommendation of KCP&L in the 2006 Rate Case and has been presented as the Company's position in the following three rate cases. Do you agree with this statement?

A: No. The Company proposed a symmetrical tracking proposal in the 2006 Rate Case. The Commission's removal of the symmetry from the OSS margin tracker was not supported by the Company. It was accepted, however, as ordered by the Commission. The following three cases demonstrated that the asymmetrical tracking system only created a significant detriment to the Company's ability to earn a fair and reasonable rate of return. The Company, however, had numerous other major issues to address in those cases. At this time, the Iatan 2 project is complete and not at issue in this case. Given the instability of the OSS market, it has become paramount that the Company, the parties and the Commission reconsider the OSS tracking mechanism.

Q: On page 38 of his Rebuttal Testimony, Mr. Featherstone claims that the asymmetrical rate mechanism in place caused the Company to have no incentive to achieve the highest level of OSS possible. Is this a true statement?

A: The real incentive the current system provides is for KPC&L to meet the target percentage that is set in base rates. Even with the requirement to refund margins attained over the target set in rates, the current mechanism would not cause the Company to wish to decrease or limit OSS. The attainment of margins over the base level would have been a positive to the Company if only for cash flow reasons, but it would have also allowed he Company to mitigate costs to customers.

As further explained in the testimony from Company witness Burton Crawford throughout this case, the declining market has had the most impact on the ability for KCP&L to sell excess power off system at the same level of margin.

Q: On page 38 of Mr. Featherstone's Rebuttal Testimony, he shows a chart presenting the OSS margins authorized and achieved in the past four rate cases. Does this support his testimony that an IEC is not needed and that the Company is discouraged by the current method of setting rates to make OSS?

A: No. It does just the opposite. The current treatment of OSS margins in rates is for the Company to refund any amount in excess of the level set in rate cases and to absorb any amount below the level set in rate cases. This chart shows the dramatic change in the OSS market and the disproportionate treatment afforded the Company during this difficult time. During the first three cases, the Company exceeded the level of OSS margins. As shown on Mr. Featherstone's schedule, this amount accounted for **[redacted]** million (total Company) for the three cases. All of the Missouri jurisdictional

amounts in excess of the level established in the rate cases are being refunded to customers based on an established amortization period. However, in the most recent rate case, the level was set at **[redacted]** million (total Company), but the actual amount achieved **[redacted]** million (total Company). The Company is **[redacted]** million short of reaching that goal. The Company absorbed the Missouri jurisdictional difference through a reduction in earnings to the Company. The reduction in OSS margins below that amount far exceeded the positive amount in the prior cases. However to the Company, the Company is returning the amounts in excess of the level set in rates, but absorbed in earnings the loss experienced since the last case. The asymmetrical approach to the treatment of OSS margins needs to be changed. The IEC as proposed by the Company addresses those issues.

Q: Finally, Mr. Featherstone and Ms. Mantle make a number of statements regarding why they believe KCP&L does not currently need an IEC. Do you agree with these statements?

A: No. Let's review those statements.

On pg. 21 of Mr. Featherstone's Rebuttal Testimony where he points out that natural gas prices are the lowest they've been in many years.

On page 32 of his Rebuttal he states,

- "The IEC mechanisms were not developed to respond to market conditions that exist currently for inexpensive natural gas and purchased power costs. Because of these current market conditions, the IEC mechanism is unnecessary."

- "Prices have already fallen to the lowest levels in years and are reflected in both KCPL and Staff's revenue requirement recommendations. Because KCPL has most of its fuel source purchased under contract its fuel costs are stable." "Considering IECs were created to address uncertain and increasing market conditions that do not exist today, KCPL does not need an IEC."

Page 33:

- "The IEC mechanism was specifically developed to address times of extreme volatile natural gas and purchased power."

Page 35:

- "It is important for an IEC mechanism to include both the costs of purchased power as well as the other fuel cost components in its forecasted fuel process in order to reduce the risk of a utility taking advantage of the process."

Page 36:

- "Because KCPL does not rely on natural gas and purchased power to any significant degree for retail customers there is not a need for an IEC like it was several years ago for either Aquila or Empire."

Ms. Mantle also claims that KCP&L MO has no need for an IEC.

Page 10:

- "KCP&L does not have fuel and purchased power volatility."

- Ms. Mantle states that the Company focuses on OSS volatility, not change in fuel and purchased power costs.

Page 11:

- Ms. Mantle states that the Company does face OSS margin volatility, but also states that the OSS margins set in rates have been restated in each of the rate cases so much of the volatility was absorbed by ratepayers.

- Ms. Mantle states: "Staff's position is that setting in KCPL's revenue requirement an amount of off-system sales margin gives KCPL great incentive to make as much off-system sales as it economically can. Likewise, setting an amount of fuel and purchased power gives KCPL great incentive to reduce its fuel and purchased power costs below that amount."

Q: Do you agree with the assessment made by Mr. Featherstone and Ms. Mantle that KCP&L does not need an IEC?

A: Absolutely not. Both Mr. Featherstone and Ms. Mantle have stated that KCP&L's fuel and purchased power costs are essentially set based upon contacted prices. While that is partially true, the main sources of volatility are that the price of natural gas, the effect of new sources of renewable energy, and the corresponding OSS margins. Mr. Burton Crawford describes some of the impacts the Company is experiencing in the OSS market. The Company has experienced extreme volatility in the last few years, particularly as it address OSS margins. Mr. Featherstone provides a good description of those volatilities.

However, the outlook on natural gas prices as well as the trend of OSS margins based on a number of economic and regulatory variables is uncertain and unpredictable. The netting and sharing aspects proposed in the IEC would allow the Company the flexibility to deal with those uncertainties, while not charging the customer an extra fee up front. With the fall of natural gas prices, the margins associated with OSS have also

fallen. The uncertainty, as well as the volatility of OSS margins in the current market cause KCP&L to have a strong need for and IEC at this time. Both Mr. Featherstone and Ms. Mantle have essentially ignored the OSS component of the IEC and only looked at the costs of fuel and purchased power.

RATE CASE EXPENSE

Q: Please discuss the rate case expense issue.

A: OPC proposes that KCP&L not be allowed to recover a significant portion of its rate case costs. The Company disagrees with this recommendation.

Q: What is the overall basis for OPC's recommendation?

A: I believe OPC's general point is that rate case costs are within a utility's control but that utilities have no incentive to control these costs. Therefore, utilities should be penalized.

Q: Is OPC's allegation addressed specifically to KCP&L?

A: No. OPC appears to have a concern with all utilities. Mr. Robertson states on page 5 of his Rebuttal Testimony, "Public Counsel has become increasingly concerned with the level of rate case expense among utilities in general." OPC's various comments, which I will rebut in this section of my testimony, do not address specific KCP&L concerns. Actually, to be more precise, OPC's comments are not specific in any regard, but are a series of generalities.

Q: Are rate case costs within a utility's control?

A: Partially. A utility can determine how it incurs costs to defend its positions, such as whether to utilize outside attorneys or consultants as opposed to internal resources, and if so which experts to utilize. However, to a large extent the level of expertise required and costs incurred is a result of the issues the various parties introduce in a rate proceeding.

A utility has a right to defend its filing and to utilize whatever resources are necessary to do so, as long as such costs incurred are prudent.

Q: Can you provide a recent KCP&L example of rate case costs being much higher than anticipated due to issues introduced by other parties, issues that were largely unanticipated when the Company prepared its initial budget of rate case costs in the proceeding?

A: Yes. In KCP&L's last rate case, Case No. ER-2010-0355 ("2010 Case"), rate case costs were more than twice as much as initially anticipated, due mainly to various prudence issues brought up by Staff regarding the construction of Iatan 2. Since the history of the Iatan 2 issue is well known to the parties in this case I will not go back over the details, but suffice it to say that KCP&L had a right to defend its position on this issue, and utilize the necessary experts to do so, and the Commission apparently agreed in its Order in that case, disallowing very little of the rate case costs incurred (less than 1%). As a reference, the Staff proposed Iatan Unit 2 disallowances of $184.7 million (total unit) while, based on the Company's successful rebuttal, the Commission ordered disallowances of $21.5 million (total unit).

Q: Can you provide an example of unanticipated costs in the current rate case?

A: Yes. MIEC/MECG has introduced many OSS issues unanticipated when the Company prepared its initial rate case expense budget. As a result, KCP&L has incurred far more expenses in rate case expenses than initially estimated to respond to the fuel and OSS data requests received to date from MIEC/MECG, coordinate and attend various meetings with them, etc. These incremental rate case costs primarily relate to our consultants, Northbridge Group, Inc. ("Northbridge").

Q: Regarding the incentive to control rate case costs, what support does OPC offer as support that KCP&L, or any utility for that matter is not incented to control rate case costs?

A: None. I believe a quote from Mr. Robertson's Rebuttal Testimony on pages 5-6 on that issue is telling:

> Company's management apparently believes that because it decides to incur outside legal and outside consultant costs to assist it in processing its request for a rate increase, those expenditures should be considered and authorized as an **automatic recovery** from ratepayers. Public Counsel believes that rationale is neither appropriate or reasonable. It is not appropriate because the idea itself results in monopolistic inefficiencies which lead to higher rates than should have actually occurred. The utility should always be **actively seeking to reduce its cost structure** so that ratepayers do not end up paying higher rates than absolutely necessary, but the **indiscriminate incurrence of excessive expenditures** runs counter to that goal. Also, it is not reasonable due to the fact that if the expenditures are to be incurred they must be done so with the understanding that they are the most cost-effective alternative and that their incurrence will be scrutinized thoroughly so as to avoid the payment of improper or unreasonable charges. Company's view that it can **spend whatever it desires** to process its rate increase request, because the expenditures are an **entitlement subject to automatic recovery**, provides no incentive for the controlling of the costs at issue." (Emphasis added).

As can be seen from this quote, OPC's assertions are entirely generalities, with no specific points regarding utilities in general and definitely nothing specific regarding KCP&L.

Q: Nonetheless, please address OPC's assertions.

A: To assist in that regard, I set in bold above the points that I believe are the most significant. I believe these points can be summarized as follows: A utility does not control its costs and spends whatever amount it wants because it knows it can pass all costs through to ratepayers; that there is an entitlement to fully recover costs. While I cannot speak for other utilities, I can state such is not the case with KCP&L.

Q: Why do you believe the Company does not take this view?

A: I would point to two examples as being representative of the Company's attitude on this subject. First, KCP&L's corporate values are centered around a balancing of the interests of customers and shareholders, providing low cost, reliable energy to our customers, while providing long-term earnings growth for shareholders. To achieve this goal it is in the Company's best interests, and that of its customers and shareholders, to control costs. Mr. Robertson discusses the balancing of customer and shareholder interests on pages 3-4 of his Rebuttal Testimony and in general I agree with his comments on those pages and find them consistent with KCP&L's corporate values.

Q: Please discuss the second example demonstrating that KCP&L does not take cost control lightly.

A: Company witness Terry Bassham, President and Chief Executive Officer ("CEO") discusses the specific measures KCP&L has taken to control costs in his Direct Testimony in this case (pages 9-10). He addresses the Organization Realignment and Voluntary Separation plan (referred to as "ORVS"), flat non-fuel operations and maintenance budgets, capital budget review and non-critical project delays, Supply Chain Transformation Program, and the Generation division benchmarking project.

Q: Can you provide some examples in the capital cost control area?

A: Yes. KCP&L has demonstrated its capital cost controls in recent large construction projects, including the Iatan 1 Air Quality Control System and Iatan 2, both of which resulted in minimal disallowances in recent Company rate cases (less than 1%).

Q: Is this same attitude regarding cost control applicable to rate case costs?

A: Yes, definitely. The Company's control of these costs begins with budgeting and goes on from there through vendor procurement, invoice approval, monthly cost report review, etc. The steps KCP&L employs in this process are documented in a flowchart attached to Mr. John Weisensee's Rebuttal Testimony, Schedule JPW-8.

Q: Did the Commission disallow significant KCP&L rate case costs in the 2010 Case?

A: No. The total disallowance was only $245,000, or less than 5% of rate case costs incurred in that case, a case that I mentioned earlier was very complex with many issues to address.

Q: If a utility has these rate case cost controls in place, isn't it still possible that it will incur costs that are not prudent and should be disallowed?

A: Yes. As just stated, the Commission disallowed some costs in the 2010 Case. The Company fully endorses the scrutiny of rate case costs and the disallowance of imprudent rate case costs, or any cost for that matter. The problem with OPC's recommendations is that OPC does not present one piece of evidence that any of the costs that the Company has incurred in this case, or is expected to incur based on KCP&L's rate case budget, is imprudent.

Q: Please discuss OPC's three proposed "solutions" to its perceived problem of KCP&L not controlling rate case costs.

A: First, I would state that no solutions are necessary, since OPC provided no specific concerns regarding KCP&L's cost controls or costs incurred in this case. However, I will address each of OPC's recommended "solutions." The first proposal is a sharing mechanism. Mr. Robertson states on page 3 of his Rebuttal Testimony that "Since

shareholders benefit from the activities from which rate case costs are derived, as much as, if not more than ratepayers, shareholders should also bear some of the burden of rate case expense."

Q: What concerns do you have with this recommendation?

A: This suggestion ignores the regulatory process. It is the existence of the regulatory process that requires the regulated company to incur rate case expenses. If not for the regulatory framework, a public utility would be like the seller of any unregulated commodity and would be able to change its rates without approval and would not incur rate case expense. Because a regulatory review is necessary to adjust rates, costs incurred to present and defend the case should be fully recoverable in rates, provided the costs are prudently incurred. Like any other prudently incurred cost, a utility is allowed to recover its costs under the regulatory compact.

Q: Does OPC provide an example as to why a sharing mechanism is appropriate?

A: Yes. Mr. Robertson uses Advertising Expense as an example on page 10 of his Rebuttal Testimony, stating that while general and safety advertising is recoverable from ratepayers, the cost of goodwill advertising is borne by shareholders. He feels the same applies to rate case expense.

Q: Is this an appropriate analogy?

A: No. The Company agrees that certain advertising expense is "corporate image"-related and should not be charged to ratepayers and has removed such costs in its filing (see the Adjustment CS-90 section of my Direct Testimony). The removal of advertising costs from cost of service is not a sharing mechanism, but a removal of costs that should not be borne by ratepayers.

Q: Do you have any examples or analogies supporting the Company's position that rate case costs should not be shared?

A: Yes. Payroll costs are a good example. OPC is not suggesting that these costs should be shared between ratepayers and shareholders. The same could be said for about any prudently incurred cost of doing business, including fuel costs, transmission, maintenance, etc. Once again, under the regulatory compact, a utility is allowed to recover these costs in their entirety, except for any imprudently incurred costs.

Q: Does OPC have a specific sharing percentage in mind?

A: OPC proposes a 50/50 sharing mechanism, as one alternative.

Q: What is OPC's basis for this specific recommendation?

A: I have no idea; Mr. Robertson did not state a basis.

Q: Has the Commission ever invoked a sharing mechanism for rate case costs?

A: To my knowledge, in spite of OPC's efforts at different points in time, the Commission has not ordered a sharing of reasonable, prudently incurred rate case costs.

Q: Has the Commission ever addressed this issue?

A: Yes. In re St. Joseph Light & Power Company, 2 Mo.P.S.C.3d 248, 260 (1993). The Commission stated:

> The Commission does not want to put itself in the position of discouraging necessary rate cases by discouraging rate case expense. This is a particularly treacherous area for the Commission to be addressing in that the Commission cannot be viewed as having a dampening effect upon a regulated company's statutory procedural rights to seek out a rate increase when it believes that facts so justify it. Disallowing prudently incurred rate case expense can be viewed as violating the company's procedural rights.

Q: Please discuss OPC's second "solution."

A: Its second proposal is that various rate case costs be disallowed, namely external costs (outside counsel and consultants) and internal costs.

Q: If external and internal costs are disallowed doesn't that basically eliminate recovery of most all rate case costs?

A: Yes, that covers about everything.

Q: What is OPC's concern regarding external costs?

A: OPC believes that the Company has the burden of proof and must establish that any expenditure it incurs is prudent, reasonable, and necessary, and in the opinion of OPC that has not occurred. Mr. Robertson further states on page 8 of his Rebuttal Testimony that since the Company is using outside vendors those costs are not cost-effective and therefore not reasonable or prudent.

Q: Do you agree with this justification?

A: No. As a company, we strive to balance cost control measures with providing the best level of service possible. In the Rebuttal Testimony of John Weisensee, Schedule JPW-8, is a flowchart which depicts the process the Company utilizes to manage rate case expense and ensure the monitoring and control of those costs. I agree that KCP&L bears the burden of proof, but the Company has laid out its estimated rate case costs for this case, has provided various data request responses (and updates), and OPC has not challenged one single specific cost. Once again, if OPC has specific concerns regarding external rate case costs they should present those concerns to the Commission. Otherwise, the Company has a right to utilize whatever resources it deems necessary to defend its filing.

Q: What is OPC's concern regarding internal costs?

A: OPC is concerned that the Company may be doubling up on recovery of in-house rate case costs, and therefore recommends a 50% disallowance of those costs. Mr. Robertson states on pages 8-9 of his Rebuttal Testimony:

> For example, rate case expense should not include recovery for expenses that are otherwise included in test year expenses, including salaries for utility employees that prepare the filing, act as witnesses or provide the legal requirements to develop, process and implement the rate increase request. Disallowing these costs from rate case expense will avoid duplicate accounting of amounts already incorporated in operating expense.

Q: Is his concern justified?

A: OPC's concern is justified, but its facts are not. KCP&L agrees that it would be inappropriate to duplicate costs. However, there is no duplication. The rate case costs that are deferred in a regulatory asset for recovery include only incremental costs; that is, costs the Company would not otherwise incur absent the rate case. These costs include all external costs (legal, consultants, printing, etc.) and incremental internal costs such as travel expenses. The deferred costs do not include internal labor costs. Those costs continue to be recovered through the payroll annualization process.

Q: Please discuss OPC's third "solution."

A: OPC offers an alternative position to the 50/50 sharing that would allocate the actual costs incurred to shareholders and ratepayers based on a ratio of the revenue increase authorized by the Commission to the revenue increase requested by the Company.

Q: Does the Company agree with this alternative?

A: No, not at all. There is no correlation between rate case expense recovery and the ratio of the revenue increase received to the amount requested. If a utility were to be granted 100% of its request but have unreasonable or imprudent rate case costs would it be

reasonable that the utility be allowed to recover 100% of its rate case costs? At the opposite extreme, if a utility is granted no rate increase but incurs prudent costs to defend its claim should it be denied recovery of 100% its costs? As Mr. Robertson stated on page 4 of his own Rebuttal Testimony, "Customers definitely have an interest in ensuring that their utilities' rates are just and reasonable, which is the ultimate objective of any rate case, whether it results in an increase or decrease in a given utility's rates...." I believe the same could be said for the Company.

Q: Please summarize your thoughts on OPC's rate case expense proposals.

A: OPC has filled its rate case expense testimony with generalities. Its comments could be recycled and used in any utility case OPC is involved in. Rate case expense is not that different from other expenses the Company incurs; if the costs are prudent and reasonable a utility should be allowed to recover those costs in full. OPC has not provided any specific evidence to the contrary. The Commission should reject OPC's recommendation.

Q: Does that conclude your testimony?

A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	)))	Case No. ER-2012-0174

AFFIDAVIT OF TIM M. RUSH

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Tim M. Rush, being first duly sworn on his oath, states:

1. My name is Tim M. Rush. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Director, Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Surrebuttal Testimony on behalf of Kansas City Power & Light Company consisting of forty-two (42) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Tim M. Rush

Subscribed and sworn before me this 8th day of October, 2012.

Nicole A. Wehry
Notary Public

My commission expires: Feb. 4, 2015

NICOLE A. WEHRY
Notary Public - Notary Seal
State of Missouri
Commissioned for Jackson County
My Commission Expires: February 04, 2015
Commission Number: 11391200

STAFF PROPOSAL RESIDENTIAL BASE RATE - TYPICAL BILL IMPACT ANALYSIS
RATE B (GENERAL USE WITH SPACE HEAT - ONE METER)

Current RS6 (Rate B) Schedule		Staff Proposal RS6 (Rate B) Schedule	
Customer Charge	$9.00	Customer Charge	9.00
Summer:		Summer:	
First 600	$0.11028	First 600	$0.11028
Next 400	$0.11028	Next 400	$0.11028
Over 1000	$0.11028	Over 1000	$0.11028
Winter:		Winter:	
First 600	$0.07382	First 600	$0.07751
Next 400	$0.07382	Next 400	$0.07751
Over 1000	$0.04672	Over 1000	$0.04672

AVERAGE MONTHLY USAGE

			WINTER KWH USAGE								
		0	250	500	750	1000	1200	1500	1750	2000
SUMMER KWH USAGE		Customer Charge	Winter Bill								
0	Current	$ 9.00	$ 27.46	$ 45.91	$ 64.37	$ 82.82	$ 92.56	$ 107.18	$ 119.36	$ 131.54
	Proposed	$ 9.00	$ 28.38	$ 47.76	$ 67.13	$ 86.51	$ 96.26	$ 110.87	$ 123.05	$ 135.23
	Change	0.00%	3.35%	4.03%	4.29%	4.46%	4.00%	3.44%	3.09%	2.81%
		Summer Bill	Annual (4 summer and 8 winter months)								
250	Current	$ 36.57	$ 365.96	$ 513.56	$ 661.24	$ 808.84	$ 886.76	$ 1,003.72	$ 1,101.16	$ 1,198.60
	Proposed	$ 36.57	$ 373.32	$ 528.36	$ 683.32	$ 838.36	$ 916.36	$ 1,033.24	$ 1,130.88	$ 1,228.12
	Change	0.00%	2.01%	2.88%	3.34%	3.65%	3.34%	2.94%	2.68%	2.46%
500	Current	$ 64.14	$ 476.24	$ 623.84	$ 771.52	$ 919.12	$ 997.04	$ 1,114.00	$ 1,211.44	$ 1,308.88
	Proposed	$ 64.14	$ 483.60	$ 638.64	$ 793.60	$ 948.64	$ 1,026.64	$ 1,143.52	$ 1,240.96	$ 1,338.40
	Change	0.00%	1.55%	2.37%	2.86%	3.21%	2.97%	2.65%	2.44%	2.26%
750	Current	$ 91.71	$ 586.52	$ 734.12	$ 881.80	$ 1,029.40	$ 1,107.32	$ 1,224.28	$ 1,321.72	$ 1,419.16
	Proposed	$ 91.71	$ 593.88	$ 748.92	$ 903.88	$ 1,058.92	$ 1,136.92	$ 1,253.80	$ 1,351.24	$ 1,448.68
	Change	0.00%	1.25%	2.02%	2.50%	2.87%	2.67%	2.41%	2.23%	2.06%
1000	Current	$ 119.28	$ 696.80	$ 844.40	$ 992.08	$ 1,139.68	$ 1,217.60	$ 1,334.56	$ 1,432.00	$ 1,529.44
	Proposed	$ 119.28	$ 704.16	$ 859.20	$ 1,014.16	$ 1,169.20	$ 1,247.20	$ 1,364.08	$ 1,461.52	$ 1,558.96
	Change	0.00%	1.06%	1.75%	2.23%	2.59%	2.43%	2.21%	2.06%	1.93%
1200	Current	$ 141.34	$ 785.04	$ 932.64	$ 1,080.32	$ 1,227.92	$ 1,305.84	$ 1,422.80	$ 1,520.24	$ 1,617.68
	Proposed	$ 141.34	$ 792.40	$ 947.44	$ 1,102.40	$ 1,257.44	$ 1,335.44	$ 1,452.32	$ 1,549.76	$ 1,647.20
	Change	0.00%	0.94%	1.59%	2.04%	2.40%	2.27%	2.07%	1.94%	1.82%
1500	Current	$ 174.42	$ 917.36	$ 1,064.96	$ 1,212.64	$ 1,360.24	$ 1,438.16	$ 1,555.12	$ 1,652.56	$ 1,750.00
	Proposed	$ 174.42	$ 924.72	$ 1,079.76	$ 1,234.72	$ 1,389.76	$ 1,467.76	$ 1,584.64	$ 1,682.08	$ 1,779.52
	Change	0.00%	0.80%	1.39%	1.82%	2.17%	2.06%	1.90%	1.79%	1.69%
1750	Current	$ 201.99	$ 1,027.64	$ 1,175.24	$ 1,322.92	$ 1,470.52	$ 1,548.44	$ 1,665.40	$ 1,762.84	$ 1,860.28
	Proposed	$ 201.99	$ 1,035.00	$ 1,190.04	$ 1,345.00	$ 1,500.04	$ 1,578.04	$ 1,694.92	$ 1,792.36	$ 1,889.80
	Change	0.00%	0.72%	1.26%	1.67%	2.01%	1.91%	1.77%	1.67%	1.59%
2000	Current	$ 229.56	$ 1,137.92	$ 1,285.52	$ 1,433.20	$ 1,580.80	$ 1,658.72	$ 1,775.68	$ 1,873.12	$ 1,970.56
	Proposed	$ 229.56	$ 1,145.28	$ 1,300.32	$ 1,455.28	$ 1,610.32	$ 1,688.32	$ 1,805.20	$ 1,902.64	$ 2,000.08
	Change	0.00%	0.65%	1.15%	1.54%	1.87%	1.78%	1.66%	1.58%	1.50%
2500	Current	$ 284.70	$ 1,358.48	$ 1,506.08	$ 1,653.76	$ 1,801.36	$ 1,879.28	$ 1,996.24	$ 2,093.68	$ 2,191.12
	Proposed	$ 284.70	$ 1,365.84	$ 1,520.88	$ 1,675.84	$ 1,830.88	$ 1,908.88	$ 2,025.76	$ 2,123.20	$ 2,220.64
	Change	0.00%	0.54%	0.98%	1.34%	1.64%	1.58%	1.48%	1.41%	1.35%

STAFF PROPOSED RESIDENTIAL BASE RATE - TYPICAL BILL IMPACT ANALYSIS
RATE C (GENERAL USE AND SPACE HEAT - 2 METERS)

Current RS2/RS3 (Rate C) Schedule			Staff Proposed RS2/RS3 (Rate C) Schedule		
Customer Charge		11.05	Customer Charge		11.05
Summer:			Summer:		
	First 600	$0.11028		First 600	$0.11028
	Next 400	$0.11028		Next 400	$0.11028
	Over 1000	$0.11028		Over 1000	$0.11028
Winter:			Winter:		
	First 600	$0.09914		First 600	$0.09914
	Next 400	$0.05945		Next 400	$0.05945
	Over 1000	$0.04968		Over 1000	$0.04968
S/H Meter	All KWH	$0.04747	S/H Meter	All KWH	$0.04984

AVERAGE MONTHLY USAGE

			WINTER KWH USAGE											
	General	0	300	300	600	600	600	750	750	1000	1000	1000	1500	2000
	Space Heat	0	300	500	300	500	750	500	1000	750	1000	1250	1500	2000
SUMMER KWH USAGE		Customer Charge	Winter Bill											
0	Current	$ 11.05	$ 55.03	$ 64.53	$ 84.78	$ 94.27	$ 106.14	$ 103.19	$ 126.92	$ 129.92	$ 141.78	$ 153.65	$ 190.36	$ 238.93
	Proposed	$ 11.05	$ 55.75	$ 65.71	$ 85.49	$ 95.46	$ 107.92	$ 104.37	$ 129.30	$ 131.70	$ 144.16	$ 156.62	$ 193.92	$ 243.68
	Change	0.00%	1.31%	1.83%	0.84%	1.26%	1.68%	1.14%	1.88%	1.37%	1.68%	1.93%	1.87%	1.99%
		Summer Bill	Annual (4 summer and 8 winter months)											
300	Current	$ 44.13	$ 616.76	$ 692.76	$ 854.76	$ 930.68	$ 1,025.64	$ 1,002.04	$ 1,191.88	$ 1,215.88	$ 1,310.76	$ 1,405.72	$ 1,699.40	$ 2,087.96
	Proposed	$ 44.13	$ 622.52	$ 702.20	$ 860.44	$ 940.20	$ 1,039.88	$ 1,011.48	$ 1,210.92	$ 1,230.12	$ 1,329.80	$ 1,429.48	$ 1,727.88	$ 2,125.96
	Change	0.00%	0.93%	1.36%	0.66%	1.02%	1.39%	0.94%	1.60%	1.17%	1.45%	1.69%	1.68%	1.82%
500	Current	$ 66.19	$ 705.00	$ 781.00	$ 943.00	$ 1,018.92	$ 1,113.88	$ 1,090.28	$ 1,280.12	$ 1,304.12	$ 1,399.00	$ 1,493.96	$ 1,787.64	$ 2,176.20
	Proposed	$ 66.19	$ 710.76	$ 790.44	$ 948.68	$ 1,028.44	$ 1,128.12	$ 1,099.72	$ 1,299.16	$ 1,318.36	$ 1,418.04	$ 1,517.72	$ 1,816.12	$ 2,214.20
	Change	0.00%	0.82%	1.21%	0.60%	0.93%	1.28%	0.87%	1.49%	1.09%	1.36%	1.59%	1.59%	1.75%
750	Current	$ 93.76	$ 815.28	$ 891.28	$ 1,053.28	$ 1,129.20	$ 1,224.16	$ 1,200.56	$ 1,390.40	$ 1,414.40	$ 1,509.28	$ 1,604.24	$ 1,897.92	$ 2,286.48
	Proposed	$ 93.76	$ 821.04	$ 900.72	$ 1,058.96	$ 1,138.72	$ 1,238.40	$ 1,210.00	$ 1,409.44	$ 1,428.64	$ 1,528.32	$ 1,628.00	$ 1,926.40	$ 2,324.48
	Change	0.00%	0.71%	1.06%	0.54%	0.84%	1.16%	0.78%	1.37%	1.01%	1.26%	1.48%	1.50%	1.66%
900	Current	$ 110.30	$ 881.44	$ 957.44	$ 1,119.44	$ 1,195.36	$ 1,290.32	$ 1,266.72	$ 1,456.56	$ 1,480.56	$ 1,575.44	$ 1,670.40	$ 1,964.08	$ 2,352.64
	Proposed	$ 110.30	$ 887.20	$ 966.88	$ 1,125.12	$ 1,204.88	$ 1,304.56	$ 1,276.16	$ 1,475.60	$ 1,494.80	$ 1,594.48	$ 1,694.16	$ 1,992.56	$ 2,390.64
	Change	0.00%	0.65%	0.99%	0.51%	0.80%	1.10%	0.75%	1.31%	0.96%	1.21%	1.42%	1.45%	1.62%
1000	Current	$ 121.33	$ 925.56	$ 1,001.56	$ 1,163.56	$ 1,239.48	$ 1,334.44	$ 1,310.84	$ 1,500.68	$ 1,524.68	$ 1,619.56	$ 1,714.52	$ 2,008.20	$ 2,396.76
	Proposed	$ 121.33	$ 931.32	$ 1,011.00	$ 1,169.24	$ 1,249.00	$ 1,348.68	$ 1,320.28	$ 1,519.72	$ 1,538.92	$ 1,638.60	$ 1,738.28	$ 2,036.68	$ 2,434.76
	Change	0.00%	0.62%	0.94%	0.49%	0.77%	1.07%	0.72%	1.27%	0.93%	1.18%	1.39%	1.42%	1.59%
1250	Current	$ 148.90	$ 1,035.84	$ 1,111.84	$ 1,273.84	$ 1,349.76	$ 1,444.72	$ 1,421.12	$ 1,610.96	$ 1,634.96	$ 1,729.84	$ 1,824.80	$ 2,118.48	$ 2,507.04
	Proposed	$ 148.90	$ 1,041.60	$ 1,121.28	$ 1,279.52	$ 1,359.28	$ 1,458.96	$ 1,430.56	$ 1,630.00	$ 1,649.20	$ 1,748.88	$ 1,848.56	$ 2,146.96	$ 2,545.04
	Change	0.00%	0.56%	0.85%	0.45%	0.71%	0.99%	0.66%	1.18%	0.87%	1.10%	1.30%	1.34%	1.52%
1500	Current	$ 176.47	$ 1,146.12	$ 1,222.12	$ 1,384.12	$ 1,460.04	$ 1,555.00	$ 1,531.40	$ 1,721.24	$ 1,745.24	$ 1,840.12	$ 1,935.08	$ 2,228.76	$ 2,617.32
	Proposed	$ 176.47	$ 1,151.88	$ 1,231.56	$ 1,389.80	$ 1,469.56	$ 1,569.24	$ 1,540.84	$ 1,740.28	$ 1,759.48	$ 1,859.16	$ 1,958.84	$ 2,257.24	$ 2,655.32
	Change	0.00%	0.50%	0.77%	0.41%	0.65%	0.92%	0.62%	1.11%	0.82%	1.03%	1.23%	1.28%	1.45%
2000	Current	$ 231.61	$ 1,366.68	$ 1,442.68	$ 1,604.68	$ 1,680.60	$ 1,775.56	$ 1,751.96	$ 1,941.80	$ 1,965.80	$ 2,060.68	$ 2,155.64	$ 2,449.32	$ 2,837.88
	Proposed	$ 231.61	$ 1,372.44	$ 1,452.12	$ 1,610.36	$ 1,690.12	$ 1,789.80	$ 1,761.40	$ 1,960.84	$ 1,980.04	$ 2,079.72	$ 2,179.40	$ 2,477.80	$ 2,875.88
	Change	0.00%	0.42%	0.65%	0.35%	0.57%	0.80%	0.54%	0.98%	0.72%	0.92%	1.10%	1.16%	1.34%
3000	Current	$ 341.89	$ 1,807.80	$ 1,883.80	$ 2,045.80	$ 2,121.72	$ 2,216.68	$ 2,193.08	$ 2,382.92	$ 2,406.92	$ 2,501.80	$ 2,596.76	$ 2,890.44	$ 3,279.00
	Proposed	$ 341.89	$ 1,813.56	$ 1,893.24	$ 2,051.48	$ 2,131.24	$ 2,230.92	$ 2,202.52	$ 2,401.96	$ 2,421.16	$ 2,520.84	$ 2,620.52	$ 2,918.92	$ 3,317.00
	Change	0.00%	0.32%	0.50%	0.28%	0.45%	0.64%	0.43%	0.80%	0.59%	0.76%	0.91%	0.99%	1.16%

MGE Proposal RESIDENTIAL BASE RATE - TYPICAL BILL IMPACT ANALYSIS
RATE B (GENERAL USE WITH SPACE HEAT - ONE METER)

Current RS6 (Rate B) Schedule			MGE Proposal RS6 (Rate B) Schedule		
Customer Charge		$9.00	Customer Charge		9.00
Summer:			Summer:		
	First 600	$0.11028		First 600	$0.11028
	Next 400	$0.11028		Next 400	$0.11028
	Over 1000	$0.11028		Over 1000	$0.11028
Winter:			Winter:		
	First 600	$0.07382		First 600	$0.09914
	Next 400	$0.07382		Next 400	$0.05945
	Over 1000	$0.04872		Over 1000	$0.04968

AVERAGE MONTHLY USAGE

			WINTER KWH USAGE								
			0	250	500	750	1000	1200	1500	1750	2000
SUMMER KWH USAGE			Customer Charge	Winter Bill							
0	Current		$ 9.00	$ 27.46	$ 45.91	$ 64.37	$ 82.82	$ 92.56	$ 107.18	$ 119.36	$ 131.54
	Proposed		$ 9.00	$ 33.79	$ 58.57	$ 77.40	$ 92.28	$ 102.20	$ 117.10	$ 129.52	$ 141.94
	Change		0.00%	23.05%	27.58%	20.24%	11.46%	10.41%	9.26%	8.51%	7.91%
			Summer Bill	Annual (4 summer and 8 winter months)							
250	Current		$ 36.57	$ 385.96	$ 513.56	$ 661.24	$ 808.84	$ 886.76	$ 1,003.72	$ 1,101.16	$ 1,198.60
	Proposed		$ 36.57	$ 416.60	$ 614.64	$ 765.48	$ 884.36	$ 963.88	$ 1,083.08	$ 1,182.44	$ 1,281.80
	Change		0.00%	13.84%	19.72%	15.76%	9.34%	8.70%	7.91%	7.36%	6.94%
500	Current		$ 64.14	$ 476.24	$ 623.84	$ 771.52	$ 919.12	$ 997.04	$ 1,114.00	$ 1,211.44	$ 1,308.88
	Proposed		$ 64.14	$ 526.88	$ 725.12	$ 875.76	$ 994.64	$ 1,074.16	$ 1,193.36	$ 1,292.72	$ 1,392.08
	Change		0.00%	10.63%	16.23%	13.51%	8.22%	7.73%	7.12%	6.71%	6.36%
750	Current		$ 91.71	$ 566.52	$ 734.12	$ 881.80	$ 1,029.40	$ 1,107.32	$ 1,224.28	$ 1,321.72	$ 1,419.16
	Proposed		$ 91.71	$ 637.16	$ 835.40	$ 986.04	$ 1,104.92	$ 1,184.44	$ 1,303.64	$ 1,403.00	$ 1,502.36
	Change		0.00%	8.63%	13.80%	11.82%	7.34%	6.96%	6.48%	6.15%	5.86%
1000	Current		$ 119.28	$ 696.80	$ 844.40	$ 992.08	$ 1,139.68	$ 1,217.60	$ 1,334.56	$ 1,432.00	$ 1,529.44
	Proposed		$ 119.28	$ 747.44	$ 945.68	$ 1,096.32	$ 1,215.20	$ 1,294.72	$ 1,413.92	$ 1,513.28	$ 1,612.64
	Change		0.00%	7.27%	11.99%	10.51%	6.63%	6.33%	5.95%	5.68%	5.44%
1200	Current		$ 141.34	$ 785.04	$ 932.64	$ 1,080.32	$ 1,227.92	$ 1,305.84	$ 1,422.80	$ 1,520.24	$ 1,617.68
	Proposed		$ 141.34	$ 835.68	$ 1,033.92	$ 1,184.56	$ 1,303.44	$ 1,382.96	$ 1,502.16	$ 1,601.52	$ 1,700.88
	Change		0.00%	6.45%	10.86%	9.65%	6.15%	5.91%	5.58%	5.35%	5.14%
1500	Current		$ 174.42	$ 917.36	$ 1,064.96	$ 1,212.64	$ 1,360.24	$ 1,438.16	$ 1,555.12	$ 1,652.56	$ 1,750.00
	Proposed		$ 174.42	$ 968.00	$ 1,166.24	$ 1,316.88	$ 1,435.76	$ 1,515.28	$ 1,634.48	$ 1,733.84	$ 1,833.20
	Change		0.00%	5.52%	9.51%	8.60%	5.55%	5.36%	5.10%	4.92%	4.75%
1750	Current		$ 201.99	$ 1,027.64	$ 1,175.24	$ 1,322.92	$ 1,470.52	$ 1,548.44	$ 1,665.40	$ 1,762.84	$ 1,860.28
	Proposed		$ 201.99	$ 1,078.28	$ 1,276.52	$ 1,427.16	$ 1,546.04	$ 1,625.56	$ 1,744.76	$ 1,844.12	$ 1,943.48
	Change		0.00%	4.93%	8.62%	7.88%	5.14%	4.98%	4.77%	4.61%	4.47%
2000	Current		$ 229.56	$ 1,137.92	$ 1,285.52	$ 1,433.20	$ 1,580.80	$ 1,658.72	$ 1,775.68	$ 1,873.12	$ 1,970.56
	Proposed		$ 229.56	$ 1,188.56	$ 1,386.80	$ 1,537.44	$ 1,656.32	$ 1,735.84	$ 1,855.04	$ 1,954.40	$ 2,053.76
	Change		0.00%	4.45%	7.88%	7.27%	4.78%	4.65%	4.47%	4.34%	4.22%
2500	Current		$ 284.70	$ 1,358.48	$ 1,506.08	$ 1,653.76	$ 1,801.36	$ 1,879.28	$ 1,996.24	$ 2,093.68	$ 2,191.12
	Proposed		$ 284.70	$ 1,409.12	$ 1,607.36	$ 1,758.00	$ 1,876.88	$ 1,956.40	$ 2,075.60	$ 2,174.96	$ 2,274.32
	Change		0.00%	3.73%	6.72%	6.30%	4.18%	4.10%	3.98%	3.88%	3.80%

MGE Proposal RESIDENTIAL BASE RATE - TYPICAL BILL IMPACT ANALYSIS
RATE C (GENERAL USE AND SPACE HEAT - 2 METERS)

Current RS2/RS3 (Rate C) Schedule			MGE Proposed RS2/RS3 (Rate C) Schedule		
Customer Charge		11.05	Customer Charge		11.05
Summer:			Summer:		
	First 600	$0.11028		First 600	$0.11028
	Next 400	$0.11028		Next 400	$0.11028
	Over 1000	$0.11028		Over 1000	$0.11028
Winter:			Winter:		
	First 600	$0.09914		First 600	$0.09914
	Next 400	$0.05945		Next 400	$0.05945
	Over 1000	$0.04968		Over 1000	$0.04968
S/H Meter	All KWH	$0.04747	S/H Meter	All KWH	$0.09914

AVERAGE MONTHLY USAGE

			WINTER KWH USAGE											
	General	0	300	300	600	600	600	750	750	1000	1000	1000	1500	2000
	Space Heat	0	300	500	300	500	750	500	1000	750	1000	1250	1500	2000
SUMMER KWH USAGE		Customer Charge	Winter Bill											
0	Current	$ 11.05	$ 55.03	$ 64.53	$ 84.78	$ 94.27	$ 106.14	$ 103.19	$ 126.92	$ 129.92	$ 141.78	$ 153.65	$ 190.36	$ 238.93
	Proposed	$ 11.05	$ 70.53	$ 90.36	$ 100.28	$ 120.10	$ 144.89	$ 129.02	$ 178.59	$ 168.67	$ 193.45	$ 218.24	$ 267.86	$ 342.27
	Change	0.00%	28.17%	40.03%	18.28%	27.40%	36.51%	25.03%	40.71%	29.83%	36.44%	42.04%	40.71%	43.25%
		Summer Bill	Annual (4 summer and 8 winter months)											
300	Current	$ 44.13	$ 616.76	$ 692.76	$ 854.76	$ 930.68	$ 1,025.64	$ 1,002.04	$ 1,191.88	$ 1,215.88	$ 1,310.76	$ 1,405.72	$ 1,699.40	$ 2,087.96
	Proposed	$ 44.13	$ 740.76	$ 899.40	$ 978.76	$ 1,137.32	$ 1,335.64	$ 1,208.68	$ 1,605.24	$ 1,525.88	$ 1,724.12	$ 1,922.44	$ 2,319.40	$ 2,914.68
	Change	0.00%	20.11%	29.83%	14.51%	22.20%	30.23%	20.62%	34.68%	25.50%	31.54%	36.76%	36.48%	39.59%
500	Current	$ 66.19	$ 705.00	$ 781.00	$ 943.00	$ 1,018.92	$ 1,113.88	$ 1,090.28	$ 1,280.12	$ 1,304.12	$ 1,399.00	$ 1,493.96	$ 1,787.64	$ 2,176.20
	Proposed	$ 66.19	$ 829.00	$ 987.64	$ 1,067.00	$ 1,225.56	$ 1,423.88	$ 1,296.92	$ 1,693.48	$ 1,614.12	$ 1,812.36	$ 2,010.68	$ 2,407.64	$ 3,002.92
	Change	0.00%	17.59%	26.46%	13.15%	20.28%	27.83%	18.95%	32.29%	23.77%	29.55%	34.59%	34.68%	37.99%
750	Current	$ 93.76	$ 815.28	$ 891.28	$ 1,053.28	$ 1,129.20	$ 1,224.16	$ 1,200.56	$ 1,390.40	$ 1,414.40	$ 1,509.28	$ 1,604.24	$ 1,897.92	$ 2,286.48
	Proposed	$ 93.76	$ 939.28	$ 1,097.92	$ 1,177.28	$ 1,335.84	$ 1,534.16	$ 1,407.20	$ 1,803.76	$ 1,724.40	$ 1,922.64	$ 2,120.96	$ 2,517.92	$ 3,113.20
	Change	0.00%	15.21%	23.18%	11.77%	18.30%	25.32%	17.21%	29.73%	21.92%	27.38%	32.21%	32.67%	36.16%
900	Current	$ 110.30	$ 881.44	$ 957.44	$ 1,119.44	$ 1,195.36	$ 1,290.32	$ 1,266.72	$ 1,456.56	$ 1,480.56	$ 1,575.44	$ 1,670.40	$ 1,964.08	$ 2,352.64
	Proposed	$ 110.30	$ 1,005.44	$ 1,164.08	$ 1,243.44	$ 1,402.00	$ 1,600.32	$ 1,473.36	$ 1,869.92	$ 1,790.56	$ 1,988.80	$ 2,187.12	$ 2,584.08	$ 3,179.36
	Change	0.00%	14.07%	21.58%	11.08%	17.29%	24.03%	16.31%	28.38%	20.94%	26.24%	30.93%	31.57%	35.14%
1000	Current	$ 121.33	$ 925.56	$ 1,001.56	$ 1,163.56	$ 1,239.48	$ 1,334.44	$ 1,310.84	$ 1,500.68	$ 1,524.68	$ 1,619.56	$ 1,714.52	$ 2,008.20	$ 2,396.76
	Proposed	$ 121.33	$ 1,049.56	$ 1,208.20	$ 1,287.56	$ 1,446.12	$ 1,644.44	$ 1,517.48	$ 1,914.04	$ 1,834.68	$ 2,032.92	$ 2,231.24	$ 2,628.20	$ 3,223.48
	Change	0.00%	13.40%	20.63%	10.66%	16.67%	23.23%	15.76%	27.54%	20.33%	25.52%	30.14%	30.87%	34.49%
1250	Current	$ 148.90	$ 1,035.84	$ 1,111.84	$ 1,273.84	$ 1,349.76	$ 1,444.72	$ 1,421.12	$ 1,610.96	$ 1,634.96	$ 1,729.84	$ 1,824.80	$ 2,118.48	$ 2,507.04
	Proposed	$ 148.90	$ 1,159.84	$ 1,318.48	$ 1,397.84	$ 1,556.40	$ 1,754.72	$ 1,627.76	$ 2,024.32	$ 1,944.96	$ 2,143.20	$ 2,341.52	$ 2,738.48	$ 3,333.76
	Change	0.00%	11.97%	18.59%	9.73%	15.31%	21.46%	14.54%	25.66%	18.96%	23.90%	28.32%	29.27%	32.98%
1500	Current	$ 176.47	$ 1,146.12	$ 1,222.12	$ 1,384.12	$ 1,460.04	$ 1,555.00	$ 1,531.40	$ 1,721.24	$ 1,745.24	$ 1,840.12	$ 1,935.08	$ 2,228.76	$ 2,617.32
	Proposed	$ 176.47	$ 1,270.12	$ 1,428.76	$ 1,508.12	$ 1,666.68	$ 1,865.00	$ 1,738.04	$ 2,134.60	$ 2,055.24	$ 2,253.48	$ 2,451.80	$ 2,848.76	$ 3,444.04
	Change	0.00%	10.82%	16.81%	8.98%	14.15%	19.94%	13.49%	24.02%	17.78%	22.46%	26.70%	27.82%	31.59%
2000	Current	$ 231.61	$ 1,366.68	$ 1,442.68	$ 1,604.68	$ 1,680.60	$ 1,775.56	$ 1,751.96	$ 1,941.80	$ 1,965.80	$ 2,060.68	$ 2,155.64	$ 2,449.32	$ 2,837.88
	Proposed	$ 231.61	$ 1,490.68	$ 1,649.32	$ 1,728.68	$ 1,887.24	$ 2,085.56	$ 1,958.60	$ 2,355.16	$ 2,275.80	$ 2,474.04	$ 2,672.36	$ 3,069.32	$ 3,664.60
	Change	0.00%	9.07%	14.32%	7.73%	12.30%	17.46%	11.79%	21.29%	15.77%	20.06%	23.97%	25.31%	29.13%
3000	Current	$ 341.89	$ 1,807.80	$ 1,883.80	$ 2,045.80	$ 2,121.72	$ 2,216.68	$ 2,193.08	$ 2,382.92	$ 2,406.92	$ 2,501.80	$ 2,596.76	$ 2,890.44	$ 3,279.00
	Proposed	$ 341.89	$ 1,931.80	$ 2,090.44	$ 2,169.80	$ 2,328.36	$ 2,526.68	$ 2,399.72	$ 2,796.28	$ 2,716.92	$ 2,915.16	$ 3,113.48	$ 3,510.44	$ 4,105.72
	Change	0.00%	6.86%	10.97%	6.06%	9.74%	13.98%	9.42%	17.35%	12.88%	16.52%	19.90%	21.45%	25.21%

PROPOSED LARGE GENERAL BASE RATE - TYPICAL BILL IMPACT ANALYSIS
SECONDARY VOLTAGE, ALL ELECTRIC (ONE METER) - LGSSA

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Company Proposed LGA Secondary Schedule			
Customer Charge		**Energy Charge:**	
Metered Service:		Summer:	
0-24 kw	$104.71	0-180 hrs use/mth	$0.08786
25-199 kw	$104.71	181-360 hrs use/mth	$0.06517
200-999 kw	$104.71	Over 360 hrs use/mth	$0.04901
1000 kw or above	$894.04	Winter:	
		0-180 hrs use/mth	$0.07041
Facilities Charge:	$3.00	181-360 hrs use/mth	$0.04316
Demand Charge:		Over 360 hrs use/mth	$0.03611
Summer	$5.982		
Winter	$2.991		

Staff Proposed LGA Secondary Schedule			
Customer Charge		**Energy Charge:**	
Metered Service:		Summer:	
0-24 kw	$104.71	0-180 hrs use/mth	$0.08786
25-199 kw	$104.71	181-360 hrs use/mth	$0.06517
200-999 kw	$104.71	Over 360 hrs use/mth	$0.04901
1000 kw or above	$894.04	Winter:	
		0-180 hrs use/mth	$0.07393
Facilities Charge:	$3.00	181-360 hrs use/mth	$0.04316
Demand Charge:		Over 360 hrs use/mth	$0.03611
Summer	$5.982		
Winter	$2.991		

AVERAGE MONTHLY USAGE

			WINTER KWH USAGE											
	Actual kW (Demand)		0	100	300	300	500	500	750	1000	1000	1500	1500	2000
	kwh (Energy)		0	10000	10000	100000	100000	150000	279312	500000	500000	750000	1000000	1000000
SUMMER KWH USAGE														
Actual kw (Demand)	kwh (Energy)		Customer Charge	Winter Bill										
0	0	Current	$104.71	$ 1,704.81	$ 2,601.91	$ 7,685.31	$ 9,861.71	$ 12,019.71	$ 20,255.67	$ 28,224.71	$ 32,359.04	$ 41,396.54	$ 48,108.54	$ 57,134.04	$ 63,844.04
		Proposed	$104.71	$ 1,739.82	$ 2,637.12	$ 7,675.42	$ 10,178.56	$ 12,338.56	$ 20,730.93	$ 28,899.38	$ 33,002.73	$ 42,030.23	$ 49,057.68	$ 58,084.58	$ 65,111.42
		Change	0.00%	2.07%	1.35%	-0.13%	3.21%	2.64%	2.35%	2.39%	1.99%	1.53%	1.98%	1.66%	1.99%
			Summer Bill	Annual (4 summer and 8 winter months)										
100	10000	Current	$ 2,479.31	$ 23,554.12	$ 30,732.52	$ 71,399.72	$ 88,810.92	$ 106,074.92	$ 171,962.60	$ 235,714.92	$ 268,869.56	$ 341,089.56	$ 394,769.56	$ 466,989.56	$ 520,669.56
		Proposed	$ 2,479.31	$ 23,835.80	$ 31,014.20	$ 72,920.80	$ 91,345.72	$ 108,609.72	$ 175,764.88	$ 239,517.08	$ 273,939.08	$ 346,159.08	$ 402,373.88	$ 474,593.88	$ 530,808.60
		Change	0.00%	1.20%	0.92%	2.13%	2.85%	2.39%	2.21%	1.61%	1.89%	1.49%	1.93%	1.63%	1.95%
400	50000	Current	$ 8,088.91	$ 46,992.52	$ 53,170.92	$ 93,838.12	$ 111,249.32	$ 128,513.32	$ 194,401.00	$ 258,153.32	$ 291,307.96	$ 363,527.96	$ 417,207.96	$ 489,427.96	$ 543,107.96
		Proposed	$ 8,088.91	$ 48,274.20	$ 53,452.60	$ 95,359.00	$ 113,784.12	$ 131,048.12	$ 198,203.08	$ 261,955.48	$ 296,377.48	$ 368,597.48	$ 424,812.28	$ 497,032.28	$ 553,247.00
		Change	0.00%	0.61%	0.53%	1.62%	2.28%	1.97%	1.96%	1.47%	1.74%	1.38%	1.82%	1.55%	1.87%
800	100000	Current	$ 14,277.51	$ 70,746.92	$ 77,925.32	$ 118,592.52	$ 136,003.72	$ 153,267.72	$ 219,155.40	$ 282,907.72	$ 316,062.36	$ 388,282.36	$ 441,962.36	$ 514,182.36	$ 567,862.36
		Proposed	$ 14,277.51	$ 71,028.60	$ 78,207.00	$ 120,113.40	$ 138,538.52	$ 155,802.52	$ 222,957.48	$ 286,709.88	$ 321,131.88	$ 393,351.88	$ 449,566.68	$ 521,786.68	$ 578,001.40
		Change	0.00%	0.40%	0.36%	1.28%	1.88%	1.65%	1.73%	1.34%	1.60%	1.31%	1.72%	1.48%	1.79%
800	150000	Current	$ 20,329.97	$ 94,956.76	$ 102,135.16	$ 142,802.36	$ 160,213.56	$ 177,477.56	$ 243,365.24	$ 307,117.56	$ 340,272.20	$ 412,492.20	$ 466,172.20	$ 538,392.20	$ 592,072.20
		Proposed	$ 20,329.97	$ 96,238.44	$ 102,416.84	$ 144,323.24	$ 162,748.36	$ 180,012.36	$ 247,167.32	$ 310,919.72	$ 345,341.72	$ 417,561.72	$ 473,776.52	$ 545,996.52	$ 602,211.24
		Change	0.00%	0.50%	0.28%	1.07%	1.68%	1.43%	1.58%	1.24%	1.47%	1.23%	1.63%	1.41%	1.71%
1000	200000	Current	$ 26,990.24	$ 121,597.64	$ 128,776.24	$ 169,443.44	$ 186,854.64	$ 204,118.64	$ 270,006.32	$ 333,758.64	$ 366,913.28	$ 439,133.28	$ 492,813.28	$ 565,033.28	$ 618,713.28
		Proposed	$ 26,990.24	$ 121,879.52	$ 129,057.92	$ 170,964.32	$ 189,389.44	$ 206,653.44	$ 273,808.40	$ 337,560.80	$ 371,982.80	$ 444,202.80	$ 500,417.60	$ 572,637.60	$ 628,852.32
		Change	0.00%	0.23%	0.22%	0.89%	1.36%	1.24%	1.41%	1.14%	1.36%	1.15%	1.54%	1.35%	1.61%
1200	356882	Current	$ 39,812.34	$ 172,886.24	$ 180,064.84	$ 220,731.84	$ 238,143.04	$ 255,407.04	$ 321,294.72	$ 385,047.04	$ 418,201.68	$ 490,421.68	$ 544,101.68	$ 616,321.68	$ 670,001.68
		Proposed	$ 39,812.34	$ 173,167.92	$ 180,346.32	$ 222,252.72	$ 240,677.84	$ 257,941.84	$ 325,096.80	$ 388,849.20	$ 423,271.20	$ 495,491.20	$ 551,706.00	$ 623,926.00	$ 680,140.72
		Change	0.00%	0.16%	0.15%	0.69%	1.06%	0.99%	1.18%	0.99%	1.21%	1.03%	1.40%	1.23%	1.51%
1500	700000	Current	$ 63,520.74	$ 287,719.84	$ 274,898.24	$ 315,565.44	$ 332,976.64	$ 350,240.64	$ 416,128.32	$ 479,880.64	$ 513,035.28	$ 585,255.28	$ 638,935.28	$ 711,155.28	$ 764,835.28
		Proposed	$ 63,520.74	$ 288,001.52	$ 275,179.92	$ 317,086.32	$ 335,511.44	$ 352,776.44	$ 419,930.40	$ 483,682.80	$ 518,104.80	$ 590,324.80	$ 646,539.60	$ 718,759.60	$ 774,974.32
		Change	0.00%	0.11%	0.10%	0.48%	0.76%	0.72%	0.91%	0.79%	0.99%	0.87%	1.18%	1.07%	1.33%
2000	1000000	Current	$ 87,663.64	$ 384,291.44	$ 371,469.84	$ 412,137.04	$ 429,548.24	$ 446,812.24	$ 512,699.92	$ 576,452.24	$ 609,606.88	$ 681,826.88	$ 735,506.88	$ 807,726.88	$ 861,406.88
		Proposed	$ 87,663.64	$ 384,573.12	$ 371,751.52	$ 413,657.92	$ 432,083.04	$ 449,347.04	$ 516,502.00	$ 580,254.40	$ 614,676.40	$ 686,896.40	$ 743,111.20	$ 815,331.20	$ 871,545.92
		Change	0.00%	0.08%	0.08%	0.37%	0.59%	0.57%	0.74%	0.66%	0.83%	0.74%	1.03%	0.94%	1.18%
3000	2000000	Current	$ 155,553.44	$ 635,850.84	$ 643,029.04	$ 683,696.24	$ 701,107.44	$ 718,371.44	$ 784,259.12	$ 848,011.44	$ 881,166.08	$ 953,386.08	$ 1,007,066.08	$ 1,079,286.08	$ 1,132,966.08
		Proposed	$ 155,553.44	$ 636,132.32	$ 643,310.72	$ 685,217.12	$ 703,642.24	$ 720,906.24	$ 788,061.20	$ 851,813.60	$ 886,235.60	$ 958,455.60	$ 1,014,670.40	$ 1,086,890.40	$ 1,143,105.12
		Change	0.00%	0.04%	0.04%	0.22%	0.36%	0.35%	0.48%	0.45%	0.58%	0.53%	0.76%	0.70%	0.89%

PROPOSED LARGE GENERAL BASE RATE - TYPICAL BILL IMPACT ANALYSIS
PRIMARY VOLTAGE, ALL ELECTRIC (ONE METER) - LGSPA

Company Proposed LGA Primary Schedule			
Customer Charge		**Energy Charge:**	
Metered Service:		Summer:	
0-24 kw	$104.71	0-180 hrs use/mth	$0.08589
25-199 kw	$104.71	181-360 hrs use/mth	$0.06362
200-999 kw	$104.71	Over 360 hrs use/mth	$0.04786
1000 kw or above	$894.04	Winter:	
		0-180 hrs use/mth	$0.06893
Facilities Charge:	$2.48	181-360 hrs use/mth	$0.04221
Demand Charge:		Over 360 hrs use/mth	$0.03543
Summer	$5.845		
Winter	$2.911		

Staff Proposed LGA Primary Schedule			
Customer Charge		**Energy Charge:**	
Metered Service:		Summer:	
0-24 kw	$104.71	0-180 hrs use/mth	$0.08589
25-199 kw	$104.71	181-360 hrs use/mth	$0.06362
200-999 kw	$104.71	Over 360 hrs use/mth	$0.04786
1000 kw or above	$894.04	Winter:	
		0-180 hrs use/mth	$0.07238
Facilities Charge:	$2.48	181-360 hrs use/mth	$0.04221
Demand Charge:		Over 360 hrs use/mth	$0.03543
Summer	$5.845		
Winter	$2.911		

AVERAGE MONTHLY USAGE

				WINTER KWH USAGE													
		Actual kW (Demand)	0	100	300	300	500	500	750	750	1000	1000	1500	1500	2000		
		kwh (Energy)	0	10000	10000	100000	100000	150000	150000	500000	500000	1062571	750000	1000000	1000000		
SUMMER KWH USAGE																	
Actual kw (Demand)	kwh (Energy)		Customer Charge	Winter Bill													
0	0	Current	$104.71	$ 1,624.61	$ 2,412.51	$ 7,367.09	$ 9,428.01	$ 11,538.51	$ 14,089.66	$ 27,303.76	$ 31,254.44	$ 51,186.33	$ 48,434.64	$ 55,292.14	$ 61,614.84		
		Proposed	$104.71	$ 1,659.08	$ 2,446.98	$ 7,573.20	$ 9,738.20	$ 11,848.70	$ 14,554.94	$ 27,769.04	$ 31,874.81	$ 51,806.70	$ 47,365.20	$ 56,222.70	$ 62,855.58		
		Change	0.00%	2.12%	1.43%	2.52%	3.29%	2.68%	3.30%	1.76%	1.98%	1.21%	2.00%	1.68%	2.01%		
			Summer Bill	Annual (4 summer and 8 winter months)													
100	10000	Current	$ 2,381.01	$ 22,520.92	$ 26,824.12	$ 68,620.76	$ 84,948.12	$ 101,832.12	$ 122,241.32	$ 227,954.12	$ 259,559.56	$ 419,014.68	$ 381,001.16	$ 461,861.16	$ 502,442.76		
		Proposed	$ 2,381.01	$ 22,796.66	$ 29,099.88	$ 70,109.64	$ 87,429.64	$ 104,313.64	$ 125,963.56	$ 231,676.36	$ 264,522.52	$ 423,977.64	$ 388,445.64	$ 469,305.64	$ 512,368.68		
		Change	0.00%	1.22%	8.48%	2.17%	2.92%	2.44%	3.04%	1.63%	1.91%	1.18%	1.95%	1.65%	1.98%		
400	50000	Current	$ 7,730.81	$ 43,920.12	$ 50,223.32	$ 90,019.96	$ 106,347.32	$ 123,231.32	$ 143,640.52	$ 249,353.32	$ 280,958.76	$ 440,413.88	$ 402,400.36	$ 473,260.36	$ 523,841.96		
		Proposed	$ 7,730.81	$ 44,196.86	$ 50,499.06	$ 91,508.84	$ 106,828.84	$ 125,712.84	$ 147,362.76	$ 253,075.56	$ 285,921.72	$ 445,376.84	$ 409,844.84	$ 480,704.84	$ 533,767.88		
		Change	0.00%	0.63%	0.55%	1.65%	2.33%	2.01%	2.59%	1.49%	1.77%	1.13%	1.85%	1.57%	1.89%		
800	100000	Current	$ 13,691.11	$ 67,761.32	$ 74,064.52	$ 113,861.16	$ 130,188.52	$ 147,072.52	$ 167,481.72	$ 273,194.52	$ 304,799.96	$ 464,255.08	$ 426,241.56	$ 497,101.56	$ 547,683.16		
		Proposed	$ 13,691.11	$ 68,037.06	$ 74,340.28	$ 115,350.04	$ 132,670.04	$ 149,554.04	$ 171,203.96	$ 276,916.76	$ 309,762.92	$ 469,218.04	$ 433,686.04	$ 504,546.04	$ 557,609.08		
		Change	0.00%	0.41%	0.37%	1.31%	1.91%	1.69%	2.22%	1.36%	1.63%	1.07%	1.75%	1.50%	1.81%		
600	150000	Current	$ 19,517.79	$ 91,088.04	$ 97,371.24	$ 137,167.88	$ 153,495.24	$ 170,379.24	$ 190,788.44	$ 296,501.24	$ 328,106.68	$ 487,561.80	$ 449,548.28	$ 520,408.28	$ 570,989.88		
		Proposed	$ 19,517.79	$ 91,343.60	$ 97,647.00	$ 138,656.76	$ 155,976.76	$ 172,860.76	$ 194,510.68	$ 300,223.48	$ 333,069.64	$ 492,524.76	$ 456,992.76	$ 527,852.76	$ 580,915.80		
		Change	0.00%	0.30%	0.28%	1.09%	1.62%	1.46%	1.95%	1.26%	1.51%	1.02%	1.66%	1.43%	1.74%		
1000	200000	Current	$ 25,955.64	$ 116,819.44	$ 123,122.84	$ 162,919.28	$ 179,246.64	$ 196,130.64	$ 216,539.84	$ 322,252.64	$ 353,858.08	$ 513,313.20	$ 475,299.68	$ 546,159.68	$ 596,741.28		
		Proposed	$ 25,955.64	$ 117,095.20	$ 123,398.40	$ 164,408.16	$ 181,728.16	$ 198,612.16	$ 220,262.08	$ 325,974.88	$ 358,821.04	$ 518,276.16	$ 482,744.16	$ 553,604.16	$ 606,667.20		
		Change	0.00%	0.24%	0.22%	0.91%	1.38%	1.27%	1.72%	1.16%	1.40%	0.97%	1.57%	1.35%	1.66%		
1200	400000	Current	$ 41,147.16	$ 177,585.52	$ 183,888.72	$ 223,685.36	$ 240,012.72	$ 256,896.72	$ 277,305.92	$ 383,018.72	$ 414,624.16	$ 574,079.28	$ 536,065.76	$ 606,925.76	$ 657,507.36		
		Proposed	$ 41,147.16	$ 177,861.26	$ 184,164.48	$ 225,174.24	$ 242,494.24	$ 259,378.24	$ 281,028.16	$ 386,740.96	$ 419,587.12	$ 579,042.24	$ 543,510.24	$ 614,370.24	$ 667,433.28		
		Change	0.00%	0.16%	0.15%	0.67%	1.03%	0.97%	1.34%	0.97%	1.20%	0.86%	1.39%	1.23%	1.51%		
1500	700000	Current	$ 61,412.84	$ 258,648.24	$ 264,951.44	$ 304,748.08	$ 321,075.44	$ 337,959.44	$ 358,368.64	$ 464,081.44	$ 495,686.88	$ 655,142.00	$ 617,128.48	$ 687,988.48	$ 738,570.08		
		Proposed	$ 61,412.84	$ 258,924.00	$ 265,227.20	$ 306,236.96	$ 323,556.96	$ 340,440.96	$ 362,090.88	$ 467,803.68	$ 500,649.84	$ 660,104.96	$ 624,572.96	$ 695,432.96	$ 748,496.00		
		Change	0.00%	0.11%	0.10%	0.49%	0.77%	0.73%	1.04%	0.86%	1.00%	0.76%	1.21%	1.08%	1.34%		
2000	1369653	Current	$ 102,468.03	$ 422,880.00	$ 429,172.20	$ 468,968.84	$ 485,296.20	$ 502,180.20	$ 522,589.40	$ 628,302.20	$ 659,907.64	$ 819,362.76	$ 781,349.24	$ 852,209.24	$ 902,790.84		
		Proposed	$ 102,468.03	$ 423,144.76	$ 429,447.96	$ 470,457.72	$ 487,777.72	$ 504,661.72	$ 526,311.64	$ 632,024.44	$ 664,870.60	$ 824,325.72	$ 788,793.72	$ 859,653.72	$ 912,716.76		
		Change	0.00%	0.07%	0.06%	0.32%	0.51%	0.49%	0.71%	0.59%	0.75%	0.61%	0.95%	0.87%	1.10%		
3000	2000000	Current	$ 150,647.64	$ 615,587.44	$ 621,890.64	$ 661,687.28	$ 678,014.64	$ 694,898.64	$ 715,307.84	$ 821,020.64	$ 852,626.08	$ 1,012,081.20	$ 974,067.68	$ 1,044,927.68	$ 1,095,509.28		
		Proposed	$ 150,647.64	$ 615,863.20	$ 622,166.40	$ 663,176.16	$ 680,496.16	$ 697,380.16	$ 719,030.08	$ 824,742.88	$ 857,589.04	$ 1,017,044.16	$ 981,512.16	$ 1,052,372.16	$ 1,105,435.20		
		Change	0.00%	0.04%	0.04%	0.23%	0.37%	0.36%	0.52%	0.45%	0.58%	0.48%	0.76%	0.71%	0.91%		

PROPOSED MEDIUM GENERAL BASE RATE - TYPICAL BILL IMPACT ANALYSIS
SECONDARY VOLTAGE, ALL ELECTRIC (ONE METER) - MGSSA

Company Proposed MGA Secondary Schedule			
Customer Charge		**Energy Charge:**	
Metered Service:		Summer:	
0-24 kw	$51.12	0-180 hrs use/mth	$0.10159
25-199 kw	$51.12	181-360 hrs use/mth	$0.06948
200-999 kw	$103.84	Over 360 hrs use/mth	$0.05860
1000 kw or above	$886.84	Winter:	
Addtl Meter Charge-S/H	$2.38	0-180 hrs use/mth	$0.06986
Facilities Charge:	$2.97	181-360 hrs use/mth	$0.04407
Demand Charge:		Over 360 hrs use/mth	$0.03626
Summer	$3.887	**Separately Metered Space Heat:**	
Winter	$2.800	Winter	$0.05739

Staff Proposed MGA Secondary Schedule			
Customer Charge		**Energy Charge:**	
Metered Service:		Summer:	
0-24 kw	$51.12	0-180 hrs use/mth	$0.10159
25-199 kw	$51.12	181-360 hrs use/mth	$0.06948
200-999 kw	$103.84	Over 360 hrs use/mth	$0.05860
1000 kw or above	$886.64	Winter	
Addtl Meter Charge-S/H	$2.38	0-180 hrs use/mth	$0.07335
Facilities Charge:	$2.97	181-360 hrs use/mth	$0.04407
Demand Charge:		Over 360 hrs use/mth	$0.03826
Summer	$3.887	**Separately Metered Space Heat:**	
Winter	$2.800	Winter	$0.05739

AVERAGE MONTHLY USAGE

			WINTER KWH USAGE											
		Actual kW (Demand)	0	10	20	20	50	50	100	100	500	500	750	750	1200
		kwh (Energy)	0	1000	1000	3000	3000	15000	22972	100000	100000	500000	500000	1000000	1000000
SUMMER KWH USAGE															
Actual kw (Demand)	kwh (Energy)		Customer Charge	Winter Bill											
0	0	Current	$ 51.12	$ 220.68	$ 250.38	$ 390.10	$ 549.20	$ 1,232.78	$ 2,104.72	$ 5,127.50	$ 9,716.94	$ 25,485.74	$ 28,811.69	$ 47,741.69	$ 54,151.20
		Proposed	$ 51.12	$ 224.17	$ 253.87	$ 400.58	$ 559.68	$ 1,264.22	$ 2,167.59	$ 5,190.37	$ 10,031.31	$ 25,800.11	$ 29,083.25	$ 48,213.25	$ 54,905.69
		Change	0.00%	1.58%	1.39%	2.69%	1.91%	2.55%	2.99%	1.23%	3.24%	1.23%	1.65%	0.99%	1.39%
			Summer Bill	Annual (4 summer and 8 winter)											
10	500	Current	$ 228.79	$ 2,680.60	$ 2,918.20	$ 4,035.96	$ 5,308.76	$ 10,777.40	$ 17,752.92	$ 41,935.16	$ 78,650.68	$ 204,801.08	$ 229,808.68	$ 382,848.68	$ 434,124.76
		Proposed	$ 228.79	$ 2,708.52	$ 2,946.12	$ 4,119.80	$ 5,392.60	$ 11,028.92	$ 18,255.86	$ 42,438.12	$ 81,165.64	$ 207,316.04	$ 233,581.16	$ 386,621.16	$ 440,160.88
		Change	0.00%	1.04%	0.96%	2.08%	1.58%	2.33%	2.83%	1.20%	3.20%	1.23%	1.64%	0.99%	1.39%
20	1000	Current	$ 309.29	$ 3,002.80	$ 3,240.20	$ 4,357.96	$ 5,630.76	$ 11,099.40	$ 18,074.92	$ 42,257.16	$ 78,972.68	$ 205,123.08	$ 230,130.68	$ 383,170.68	$ 434,446.76
		Proposed	$ 309.29	$ 3,030.52	$ 3,268.12	$ 4,441.80	$ 5,714.60	$ 11,350.92	$ 18,577.88	$ 42,760.12	$ 81,487.64	$ 207,638.04	$ 233,903.16	$ 386,943.16	$ 440,482.88
		Change	0.00%	0.93%	0.86%	1.92%	1.49%	2.27%	2.78%	1.19%	3.18%	1.23%	1.64%	0.98%	1.39%
30	5000	Current	$ 764.78	$ 4,824.58	$ 5,062.18	$ 6,179.92	$ 7,452.72	$ 12,921.36	$ 19,896.88	$ 44,079.12	$ 80,794.64	$ 206,945.04	$ 231,952.64	$ 384,992.64	$ 436,268.72
		Proposed	$ 764.78	$ 4,852.48	$ 5,090.08	$ 6,263.76	$ 7,536.56	$ 13,172.88	$ 20,399.84	$ 44,582.08	$ 83,309.80	$ 209,460.00	$ 235,725.12	$ 388,765.12	$ 442,304.64
		Change	0.00%	0.58%	0.55%	1.36%	1.12%	1.95%	2.53%	1.14%	3.11%	1.22%	1.63%	0.98%	1.38%
50	10000	Current	$ 1,377.76	$ 7,276.48	$ 7,514.08	$ 8,631.84	$ 9,904.64	$ 15,373.28	$ 22,348.80	$ 46,531.04	$ 83,246.56	$ 209,396.96	$ 234,404.56	$ 387,444.56	$ 438,720.64
		Proposed	$ 1,377.76	$ 7,304.40	$ 7,542.00	$ 8,715.68	$ 9,988.48	$ 15,624.80	$ 22,851.76	$ 47,034.00	$ 85,761.52	$ 211,911.92	$ 238,177.04	$ 391,217.04	$ 444,756.56
		Change	0.00%	0.38%	0.37%	0.97%	0.85%	1.64%	2.25%	1.08%	3.02%	1.20%	1.61%	0.97%	1.38%
75	20000	Current	$ 2,388.48	$ 11,319.36	$ 11,556.96	$ 12,674.72	$ 13,947.52	$ 19,416.16	$ 26,391.68	$ 50,573.92	$ 87,289.44	$ 213,439.84	$ 238,447.44	$ 391,487.44	$ 442,763.52
		Proposed	$ 2,388.48	$ 11,347.28	$ 11,584.88	$ 12,758.56	$ 14,031.36	$ 19,667.68	$ 26,894.64	$ 51,076.88	$ 89,804.40	$ 215,954.80	$ 242,219.92	$ 395,259.92	$ 448,799.44
		Change	0.00%	0.25%	0.24%	0.66%	0.60%	1.30%	1.91%	0.99%	2.88%	1.18%	1.58%	0.96%	1.36%
100	29479	Current	$ 3,383.00	$ 15,217.44	$ 15,455.04	$ 16,572.80	$ 17,845.60	$ 23,314.24	$ 30,289.76	$ 54,472.00	$ 91,187.52	$ 217,337.92	$ 242,345.52	$ 395,385.52	$ 446,661.60
		Proposed	$ 3,383.00	$ 15,245.36	$ 15,482.96	$ 16,656.64	$ 17,929.44	$ 23,565.76	$ 30,792.72	$ 54,974.96	$ 93,702.48	$ 219,852.88	$ 248,118.00	$ 399,158.00	$ 452,697.52
		Change	0.00%	0.18%	0.18%	0.51%	0.47%	1.08%	1.66%	0.92%	2.76%	1.16%	1.56%	0.95%	1.35%
150	75000	Current	$ 6,929.16	$ 29,482.08	$ 29,719.68	$ 30,837.44	$ 32,110.24	$ 37,578.88	$ 44,554.40	$ 68,736.64	$ 105,452.16	$ 231,602.56	$ 256,610.16	$ 409,650.16	$ 460,926.24
		Proposed	$ 6,929.16	$ 29,510.00	$ 29,747.60	$ 30,921.28	$ 32,194.08	$ 37,830.40	$ 45,057.36	$ 69,239.60	$ 107,967.12	$ 234,117.52	$ 260,382.64	$ 413,422.64	$ 466,962.16
		Change	0.00%	0.09%	0.09%	0.27%	0.26%	0.67%	1.13%	0.73%	2.38%	1.09%	1.47%	0.92%	1.31%
500	300000	Current	$ 25,960.64	$ 105,608.00	$ 105,845.60	$ 106,963.36	$ 108,236.16	$ 113,704.80	$ 120,680.32	$ 144,862.56	$ 181,578.08	$ 307,728.48	$ 332,736.08	$ 485,776.08	$ 537,052.16
		Proposed	$ 25,960.64	$ 105,635.92	$ 105,873.52	$ 107,047.20	$ 108,320.00	$ 113,956.32	$ 121,183.28	$ 145,365.52	$ 184,093.04	$ 310,243.44	$ 336,508.56	$ 489,548.56	$ 543,088.08
		Change	0.00%	0.03%	0.03%	0.08%	0.08%	0.22%	0.42%	0.35%	1.39%	0.82%	1.13%	0.78%	1.12%
1000	500000	Current	$ 46,740.24	$ 188,726.40	$ 188,964.00	$ 190,081.76	$ 191,354.56	$ 196,823.20	$ 203,798.72	$ 227,980.96	$ 264,696.48	$ 390,846.88	$ 415,854.48	$ 568,894.48	$ 620,170.56
		Proposed	$ 46,740.24	$ 188,754.32	$ 188,991.92	$ 190,165.60	$ 191,438.40	$ 197,074.72	$ 204,301.68	$ 228,483.92	$ 267,211.44	$ 393,361.84	$ 419,626.96	$ 572,666.96	$ 626,206.48
		Change	0.00%	0.01%	0.01%	0.04%	0.04%	0.13%	0.25%	0.22%	0.95%	0.64%	0.91%	0.66%	0.97%

PROPOSED MEDIUM GENERAL BASE RATE - TYPICAL BILL IMPACT ANALYSIS
PRIMARY VOLTAGE, ALL ELECTRIC (ONE METER) - MGSPA

Company Proposed MGA Primary Schedule			
Customer Charge		**Energy Charge:**	
Metered Service:		Summer:	
0-24 kw	$51.12	0-180 hrs use/mth	$0.09917
25-199 kw	$51.12	181-360 hrs use/mth	$0.06792
200-999 kw	$103.84	Over 360 hrs use/mth	$0.05727
1000 kw or above	$888.64	Winter:	
Addtl Meter Charge-S/H	$2.38	0-180 hrs use/mth	$0.06829
Facilities Charge:	$2.46	181-360 hrs use/mth	$0.04298
Demand Charge:		Over 360 hrs use/mth	$0.03754
Summer	$3.796	**Separately Metered Space Heat:**	
Winter	$2.739	Winter	$0.00000

Staff Proposed MGA Primary Schedule			
Customer Charge		**Energy Charge:**	
Metered Service:		Summer:	
0-24 kw	$51.12	0-160 hrs use/mth	$0.09917
25-199 kw	$51.12	181-360 hrs use/mth	$0.06792
200-999 kw	$103.84	Over 360 hrs use/mth	$0.05727
1000 kw or above	$888.64	Winter:	
Addtl Meter Charge-S/H	$2.38	0-180 hrs use/mth	$0.07170
Facilities Charge:	$2.46	181-360 hrs use/mth	$0.04298
Demand Charge:		Over 360 hrs use/mth	$0.03754
Summer	$3.796	**Separately Metered Space Heat:**	
Winter	$2.739	Winter	$0.00000

AVERAGE MONTHLY USAGE

			WINTER KWH USAGE											
		Actual kW (Demand)	0	10	20	20	50	50	50	100	500	500	750	750	1200
		kwh (Energy)	0	1000	1000	3000	3000	15000	55147	100000	100000	500000	500000	1000000	1000000
SUMMER KWH USAGE															
Actual kw (Demand)	kwh (Energy)		Customer Charge	Winter Bill											
0	0	Current	$ 51.12	$ 212.51	$ 237.13	$ 373.71	$ 518.04	$ 1,183.66	$ 2,707.10	$ 4,976.64	$ 9,260.24	$ 24,731.44	$ 27,660.24	$ 46,430.24	$ 52,484.88
		Proposed	$ 51.12	$ 215.92	$ 240.54	$ 383.95	$ 526.28	$ 1,214.39	$ 2,737.83	$ 5,038.10	$ 9,567.55	$ 25,038.75	$ 28,121.20	$ 46,891.20	$ 53,222.41
		Change	0.00%	1.60%	1.44%	2.74%	1.66%	2.60%	1.14%	1.23%	3.31%	1.24%	1.67%	0.99%	1.41%
			Summer Bill	Annual (4 summer and 8 winter)											
10	500	Current	$ 220.23	$ 2,581.00	$ 2,777.96	$ 3,870.60	$ 5,009.24	$ 10,350.20	$ 22,537.72	$ 40,694.04	$ 75,122.84	$ 198,732.44	$ 222,162.84	$ 372,322.84	$ 420,759.96
		Proposed	$ 220.23	$ 2,608.28	$ 2,805.24	$ 3,952.52	$ 5,091.16	$ 10,596.04	$ 22,783.56	$ 41,185.72	$ 77,581.32	$ 201,190.92	$ 225,650.52	$ 376,010.52	$ 426,660.20
		Change	0.00%	1.06%	0.98%	2.12%	1.64%	2.38%	1.09%	1.21%	3.27%	1.24%	1.56%	0.99%	1.40%
20	1000	Current	$ 294.43	$ 2,877.60	$ 3,074.76	$ 4,167.40	$ 5,306.04	$ 10,647.00	$ 22,834.52	$ 40,990.84	$ 75,419.64	$ 199,029.24	$ 222,459.64	$ 372,619.64	$ 421,056.76
		Proposed	$ 294.43	$ 2,905.88	$ 3,102.04	$ 4,249.32	$ 5,387.96	$ 10,892.84	$ 23,080.36	$ 41,482.52	$ 77,878.12	$ 201,487.72	$ 226,147.32	$ 376,307.32	$ 426,957.00
		Change	0.00%	0.95%	0.89%	1.97%	1.54%	2.31%	1.06%	1.20%	3.26%	1.24%	1.66%	0.99%	1.40%
30	5000	Current	$ 734.71	$ 4,638.92	$ 4,835.88	$ 5,928.52	$ 7,067.16	$ 12,408.12	$ 24,595.64	$ 42,751.96	$ 77,180.76	$ 200,790.36	$ 224,220.76	$ 374,380.76	$ 422,817.88
		Proposed	$ 734.71	$ 4,666.20	$ 4,863.16	$ 6,010.44	$ 7,149.08	$ 12,653.96	$ 24,841.48	$ 43,243.64	$ 79,639.24	$ 203,248.84	$ 227,908.44	$ 378,068.44	$ 428,718.12
		Change	0.00%	0.59%	0.56%	1.38%	1.16%	1.98%	1.00%	1.15%	3.19%	1.22%	1.64%	0.99%	1.40%
50	112533	Current	$ 7,281.73	$ 30,827.00	$ 31,023.96	$ 32,116.60	$ 33,255.24	$ 38,596.20	$ 50,783.72	$ 68,940.04	$ 103,368.84	$ 226,978.44	$ 250,408.84	$ 400,568.84	$ 449,005.96
		Proposed	$ 7,281.73	$ 30,854.28	$ 31,051.24	$ 32,196.52	$ 33,337.16	$ 38,842.04	$ 51,029.56	$ 69,431.72	$ 105,827.32	$ 229,436.92	$ 254,096.52	$ 404,256.52	$ 454,906.20
		Change	0.00%	0.09%	0.09%	0.26%	0.25%	0.64%	0.48%	0.71%	2.38%	1.08%	1.47%	0.92%	1.31%
75	20000	Current	$ 2,300.75	$ 10,903.08	$ 11,100.04	$ 12,192.68	$ 13,331.32	$ 18,672.28	$ 30,859.80	$ 49,016.12	$ 83,444.92	$ 207,054.52	$ 230,484.92	$ 380,644.92	$ 429,082.04
		Proposed	$ 2,300.75	$ 10,930.36	$ 11,127.32	$ 12,274.60	$ 13,413.24	$ 18,918.12	$ 31,105.64	$ 49,507.80	$ 85,903.40	$ 209,513.00	$ 234,172.60	$ 384,332.60	$ 434,982.28
		Change	0.00%	0.25%	0.25%	0.67%	0.61%	1.32%	0.80%	1.00%	2.95%	1.19%	1.60%	0.97%	1.38%
100	30000	Current	$ 3,277.02	$ 14,608.16	$ 15,005.12	$ 16,097.76	$ 17,236.40	$ 22,577.38	$ 34,764.88	$ 52,921.20	$ 87,350.00	$ 210,958.60	$ 234,390.00	$ 384,550.00	$ 432,987.12
		Proposed	$ 3,277.02	$ 14,635.44	$ 15,032.40	$ 16,179.68	$ 17,318.32	$ 22,823.20	$ 35,010.72	$ 53,412.88	$ 89,808.48	$ 213,418.08	$ 238,077.68	$ 388,237.68	$ 438,887.36
		Change	0.00%	0.18%	0.18%	0.51%	0.48%	1.09%	0.71%	0.93%	2.81%	1.17%	1.57%	0.96%	1.36%
150	75000	Current	$ 6,703.92	$ 28,515.76	$ 28,712.72	$ 29,805.36	$ 30,944.00	$ 36,284.98	$ 48,472.48	$ 66,628.80	$ 101,057.60	$ 224,667.20	$ 248,097.60	$ 398,257.60	$ 446,694.72
		Proposed	$ 6,703.92	$ 28,543.04	$ 28,740.00	$ 29,887.28	$ 31,025.92	$ 36,530.80	$ 48,718.32	$ 67,120.48	$ 103,516.08	$ 227,125.68	$ 251,785.28	$ 401,945.28	$ 452,594.96
		Change	0.00%	0.10%	0.10%	0.27%	0.26%	0.68%	0.51%	0.74%	2.43%	1.09%	1.49%	0.93%	1.32%
500	300000	Current	$ 25,143.34	$ 102,273.44	$ 102,470.40	$ 103,563.04	$ 104,701.68	$ 110,042.64	$ 122,230.16	$ 140,386.48	$ 174,815.28	$ 298,424.88	$ 321,855.28	$ 472,015.28	$ 520,452.40
		Proposed	$ 25,143.34	$ 102,300.72	$ 102,497.68	$ 103,644.96	$ 104,783.60	$ 110,288.48	$ 122,476.00	$ 140,878.16	$ 177,273.76	$ 300,883.36	$ 325,542.96	$ 475,702.96	$ 526,352.64
		Change	0.00%	0.03%	0.03%	0.08%	0.08%	0.22%	0.20%	0.35%	1.41%	0.82%	1.15%	0.78%	1.13%
1000	500000	Current	$ 45,238.64	$ 182,654.64	$ 182,851.60	$ 183,944.24	$ 185,082.88	$ 190,423.84	$ 202,611.36	$ 220,767.68	$ 255,196.48	$ 378,806.08	$ 402,236.48	$ 552,396.48	$ 600,833.60
		Proposed	$ 45,238.64	$ 182,681.92	$ 182,878.88	$ 184,026.16	$ 185,164.80	$ 190,669.68	$ 202,857.20	$ 221,259.38	$ 257,654.96	$ 381,264.56	$ 405,924.16	$ 556,084.16	$ 606,733.84
		Change	0.00%	0.01%	0.01%	0.04%	0.04%	0.13%	0.12%	0.22%	0.96%	0.65%	0.92%	0.67%	0.98%

PROPOSED SMALL GENERAL BASE RATE - TYPICAL BILL IMPACT ANALYSIS
SECONDARY VOLTAGE, ALL ELECTRIC (ONE METER) - SGSSA

Company Proposed SGA Secondary Schedule			
Customer Charge		**Energy Charge:**	
Metered Service:		Summer:	
0-24 kw	$18.46	0-180 hrs use/mth	$0.1648
25-199 kw	$51.18	181-360 hrs use/mth	$0.0782
200-999 kw	$103.97	Over 360 hrs use/mth	$0.0697
1000 kw or above	$687.73	Winter:	
Unmetered Service	$7.74	0-180 hrs use/mth	$0.10837
Addtl Meter Charge-S/H	$2.38	181-360 hrs use/mth	$0.06439
Facilities Charge:		Over 360 hrs use/mth	$0.06133
First 25 kw	$0.00	**Separately Metered Space Heat:**	
All kw over 25kw	$2.98	Winter	$0.06856

Staff Proposed SGA Secondary Schedule			
Customer Charge		**Energy Charge:**	
Metered Service:		Summer:	
0-24 kw	$18.46	0-180 hrs use/mth	$0.1648
25-199 kw	$51.18	181-360 hrs use/mth	$0.0782
200-999 kw	$103.97	Over 360 hrs use/mth	$0.0697
1000 kw or above	$687.73	Winter:	
Unmetered Service	$7.74	0-180 hrs use/mth	$0.1117
Addtl Meter Charge-S/H	$2.38	181-360 hrs use/mth	$0.0644
Facilities Charge:		Over 360 hrs use/mth	$0.0613
First 25 kw	$0.00	**Separately Metered Space Heat:**	
All kw over 25kw	$2.98	Winter	$0.0686

AVERAGE MONTHLY USAGE

				WINTER KWH USAGE											
		Actual kW (Demand)	0	10	25	25	50	50	75	75	100	100	150	150	200
		kwh (Energy)	0	1000	1000	2600	5000	15000	15000	25000	25000	50000	50000	75000	75000
SUMMER KWH USAGE															
Actual kw (Demand)	kwh (Energy)		Customer Charge	Winter Bills											
0	0	Current	$ 18.46	$ 124.83	$ 157.55	$ 327.74	$ 657.41	$ 1,469.23	$ 1,732.51	$ 2,376.41	$ 2,639.70	$ 4,208.81	$ 4,776.02	$ 6,321.51	$ 6,955.95
		Proposed	$ 18.46	$ 130.15	$ 162.87	$ 341.57	$ 684.00	$ 1,517.09	$ 1,804.31	$ 2,448.21	$ 2,735.43	$ 4,302.34	$ 4,919.81	$ 6,465.10	$ 7,147.41
		Change	0.00%	4.26%	3.38%	4.22%	4.04%	3.26%	4.14%	3.02%	3.63%	2.26%	3.01%	2.27%	2.75%
			Summer Bills	Annual (4 summer and 8 winter months)											
10	1000	Current	$ 183.24	$ 1,731.60	$ 1,993.36	$ 3,354.88	$ 5,992.24	$ 12,486.80	$ 14,593.04	$ 19,744.24	$ 21,850.56	$ 34,385.84	$ 38,941.12	$ 51,305.04	$ 56,380.56
		Proposed	$ 183.24	$ 1,774.16	$ 2,035.92	$ 3,465.52	$ 6,204.96	$ 12,869.68	$ 15,187.44	$ 20,318.64	$ 22,616.40	$ 35,151.68	$ 40,069.84	$ 52,453.76	$ 57,912.24
		Change	0.00%	2.46%	2.14%	3.30%	3.55%	3.07%	3.94%	2.91%	3.50%	2.23%	2.95%	2.24%	2.72%
20	3200	Current	$ 545.76	$ 3,181.68	$ 3,443.44	$ 4,804.96	$ 7,442.32	$ 13,936.88	$ 16,043.12	$ 21,194.32	$ 23,300.64	$ 35,835.92	$ 40,391.20	$ 52,755.12	$ 57,830.64
		Proposed	$ 545.76	$ 3,224.24	$ 3,486.00	$ 4,915.60	$ 7,655.04	$ 14,319.76	$ 16,617.52	$ 21,768.72	$ 24,066.48	$ 36,601.76	$ 41,539.92	$ 53,903.84	$ 59,362.32
		Change	0.00%	1.34%	1.24%	2.30%	2.86%	2.75%	3.58%	2.71%	3.29%	2.14%	2.84%	2.18%	2.65%
50	7000	Current	$ 1,279.02	$ 6,114.72	$ 6,376.48	$ 7,738.00	$ 10,375.36	$ 16,869.92	$ 18,976.16	$ 24,127.36	$ 26,233.68	$ 38,768.96	$ 43,324.24	$ 55,688.16	$ 60,763.68
		Proposed	$ 1,279.02	$ 6,157.28	$ 6,419.04	$ 7,848.64	$ 10,588.08	$ 17,252.80	$ 19,550.56	$ 24,701.76	$ 26,999.52	$ 39,534.80	$ 44,472.96	$ 56,836.88	$ 62,295.36
		Change	0.00%	0.70%	0.67%	1.43%	2.05%	2.27%	3.03%	2.38%	2.92%	1.98%	2.65%	2.06%	2.52%
75	20000	Current	$ 2,932.63	$ 12,729.16	$ 12,990.92	$ 14,352.44	$ 16,989.80	$ 23,484.36	$ 25,590.60	$ 30,741.80	$ 32,848.12	$ 45,383.40	$ 49,938.68	$ 62,302.60	$ 67,378.12
		Proposed	$ 2,932.63	$ 12,771.72	$ 13,033.48	$ 14,463.08	$ 17,202.52	$ 23,867.24	$ 26,165.00	$ 31,316.20	$ 33,613.96	$ 46,149.24	$ 51,087.40	$ 63,451.32	$ 68,909.80
		Change	0.00%	0.33%	0.33%	0.77%	1.25%	1.63%	2.24%	1.87%	2.33%	1.68%	2.30%	1.84%	2.27%
100	30000	Current	$ 4,178.51	$ 17,712.68	$ 17,974.44	$ 19,335.96	$ 21,973.32	$ 28,467.88	$ 30,574.12	$ 35,725.32	$ 37,831.64	$ 50,366.92	$ 54,922.20	$ 67,286.12	$ 72,361.64
		Proposed	$ 4,178.51	$ 17,755.24	$ 18,017.00	$ 19,446.60	$ 22,186.04	$ 28,850.76	$ 31,148.52	$ 36,299.72	$ 38,597.48	$ 51,132.76	$ 56,070.92	$ 68,434.84	$ 73,893.32
		Change	0.00%	0.24%	0.24%	0.57%	0.97%	1.34%	1.88%	1.61%	2.02%	1.52%	2.09%	1.71%	2.12%
125	40000	Current	$ 5,424.38	$ 22,696.16	$ 22,957.92	$ 24,319.44	$ 26,956.80	$ 33,451.36	$ 35,557.60	$ 40,708.80	$ 42,815.12	$ 55,350.40	$ 59,905.68	$ 72,269.60	$ 77,345.12
		Proposed	$ 5,424.38	$ 22,738.72	$ 23,000.48	$ 24,430.08	$ 27,169.52	$ 33,834.24	$ 36,132.00	$ 41,283.20	$ 43,580.96	$ 56,116.24	$ 61,054.40	$ 73,418.32	$ 78,876.80
		Change	0.00%	0.19%	0.19%	0.45%	0.78%	1.14%	1.62%	1.41%	1.79%	1.36%	1.92%	1.59%	1.96%
150	75000	Current	$ 8,445.64	$ 34,782.00	$ 35,043.76	$ 36,405.28	$ 39,042.64	$ 45,537.20	$ 47,643.44	$ 52,794.64	$ 54,900.96	$ 67,436.24	$ 71,991.52	$ 84,355.44	$ 89,430.96
		Proposed	$ 8,445.64	$ 34,824.56	$ 35,086.32	$ 36,515.92	$ 39,255.36	$ 45,920.08	$ 48,217.84	$ 53,369.04	$ 55,666.80	$ 68,202.08	$ 73,140.24	$ 85,504.16	$ 90,962.64
		Change	0.00%	0.12%	0.12%	0.30%	0.54%	0.84%	1.21%	1.09%	1.39%	1.14%	1.60%	1.36%	1.71%
200	100000	Current	$ 11,321.64	$ 46,285.20	$ 46,546.96	$ 47,908.48	$ 50,545.84	$ 57,040.40	$ 59,146.64	$ 64,297.84	$ 66,404.16	$ 78,939.44	$ 83,494.72	$ 95,858.64	$ 100,934.16
		Proposed	$ 11,321.64	$ 46,327.76	$ 46,589.52	$ 48,019.12	$ 50,758.56	$ 57,423.28	$ 59,721.04	$ 64,872.24	$ 67,170.00	$ 79,705.28	$ 84,643.44	$ 97,007.36	$ 102,465.84
		Change	0.00%	0.09%	0.09%	0.23%	0.42%	0.67%	0.97%	0.89%	1.15%	0.97%	1.38%	1.20%	1.52%
250	125000	Current	$ 14,144.65	$ 57,577.24	$ 57,839.00	$ 59,200.52	$ 61,837.88	$ 68,332.44	$ 70,438.68	$ 75,589.88	$ 77,696.20	$ 90,231.48	$ 94,786.76	$ 107,150.68	$ 112,226.20
		Proposed	$ 14,144.65	$ 57,619.80	$ 57,881.56	$ 59,311.16	$ 62,050.60	$ 68,715.32	$ 71,013.08	$ 76,164.28	$ 78,462.04	$ 90,997.32	$ 95,935.48	$ 108,299.40	$ 113,757.88
		Change	0.00%	0.07%	0.07%	0.19%	0.34%	0.56%	0.82%	0.76%	0.99%	0.85%	1.21%	1.07%	1.36%