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August 5, 2011

Mr. Jeff Derouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602

RE: Case No. 2011-00037

Dear Mr. Derouen:

Please find enclosed the original and ten (10) copies of the Owen Electric Cooperative Inc's Supplemental Responses to the Attorney General's "Initial Data Requests Questions 16, 31, 32, 60, 67 and 68".

Please contact me with any questions regarding this filing.

Respectfully submitted,

CRAWFORD & BAXTER, P.S.C.

James M. Crawford

James M. Crawford

JMC/mns

Enclosures

cc: Hon. Jennifer Black Hans
Hon. Dennis G. Howard, II
Hon. Lawrence W. Cook

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF OWEN	)	
ELECTRIC COOPERATIVE, INC.	)	Case No. 2011-00037
FOR AN ADJUSTMENT OF RATES	)	

ATTORNEY GENERAL'S
MOTION TO COMPEL

Comes now the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and moves the Public Service Commission (hereinafter the "PSC" or "Commission") to compel Owen Electric Cooperative, Inc. (hereinafter "Owen") to adequately respond to certain questions which the Attorney General filed in the instant matter. Specially, the company has failed to adequately respond to the Attorney Generals' Initial Request questions 16, 31, 32, 60, 67 and 68. Unless the Commission compels Owen to respond to the discovery requests, the Attorney General and the Commission will not have access to the information necessary to make informed decisions, and the Attorney General will be deprived of procedural due process in this matter.

As a general overview, Owen has failed to adequately respond to many of the Attorney General's initial data requests on only one ground on one question and utterly failed to answer other questions which will be addressed below. The Attorney General provides the following questions in this motion for easier reference.

Question 16: The report at page 5 states that the company had created a rates task force in August 2009 to develop a request for proposal to hire a consultant to prepare a rate study based on a 2009 test year, and that the results were expected in August 2010. Provide a copy of the request for proposal, together with all responses received.

a. Provide copies of any all correspondence to and from the consultant(s) that were retained to conduct such study.
b. Provide copies of any all correspondence to and from EKPC regarding this study.
c. Provide copies of any other cost of service studies that were provided to EKPC during the past three (3) years.

Question 31: Confirm that without decoupling, EKPC, as Owen's primary generation source, has the ability to sell conserved power on the wholesale unregulated market in excess of both the wholesale rates EKPC charges to Owen, and the retail regulated rates Owen charges to its ratepayers.

a. Confirm that when Owen's ratepayers conserve energy, EKPC is able to sell that conserved power on the wholesale market, thereby reducing Owen's proportionate costs.
b. Confirm that from a general perspective, the more power Owen sells, the more its costs will increase.

Question 32: Confirm that EKPC system-wide experienced a record decline in consumption during 2009.

a. Confirm further that Owen's use of a 2009 test year in the instant proceeding to establish average use per customer will lead to customers paying for that historic decline.

Question 60: Reference the Stallons testimony, p. 2, wherein he states the purpose of the instant filing is to align the member charge with the company's fixed costs over a five-year period. Provide any and all documentation to support Owen's forecasted fixed costs over the next five years, including any and all assumptions underlying such forecasts.

a. State to what extent, if any, the company's forecasted fixed costs are dependent upon the 2008 load forecast.
b. State to what extent, if any, the company's forecasted fixed costs in the instant case relies upon the most recent load forecast.

Question 67: Reference the Stallons testimony, p.5, question no. 18, wherein Mr. Stallons defines the "throughput incentive" as an incentive "to increase fixed cost[s] and margin recovery." Does Mr. Stallon acknowledge that Owen is likewise under an incentive to maximize its fixed costs? If he does not so admit, explain why not in complete detail.

c. Is the concept of providing the lowest cost energy possible to its members not enough incentive for Owen to reduce its fixed costs? If not, why not? Please explain in complete detail.
d. Please explain the nature of the legal duty Owen believes it owes to its members.
e. If Owen institutes DSM programs and attempts to recover any sales lost as a result of the "energy innovations" Mr. Stallons describes in his answer to this question, would that not eliminate the purported "disincentive" described therein? If not, why not? Describe in complete detail.

Question 68: Reference the Stallons testimony, p.6, question no. 19, wherein he states that raising the customer charge is the "simplest way for a rural electric cooperative to mitigate the throughput incentive." Would doing so also be the most effective and efficient way? If so, why? If not, why not? Explain in complete detail.

f. If Owen also instituted DSM programs designed to recover its lost sales resulting from the implementation of energy efficiency measures, would Mr. Stallons continue to believe that raising the customer charge remains the "simplest way" to mitigate the throughput incentive?
g. If Owen also instituted DSM programs designed to recover its lost sales resulting from the implementation of energy efficiency measures, would Mr. Stallons believe that raising the customer charge would be the most effective and efficient means of mitigating the throughput incentive? If not, explain why not in complete detail.

ARGUMENT

The scope of permissible discovery before the Commission is very broad. In fact, the Commission has stated:

> While the Commission's Rules of Procedure are generally silent upon discovery, the Kentucky Civil Rules make clear that scope of discovery is quite broad. If the requested material appears reasonably calculated to lead to discovery of admissible evidence, then the request is relevant. (footnotes omitted).

> *In the Matter of: The Application of Kentucky-American Water Company for a Certificate of Public Convenience and Necessity Authorizing the Construction of Kentucky River Station II, Associated Facilities and Transmission Main,* Case No. 2007-00134, Order, 15 November 2007.

> Further, the Commission follows Kentucky Civil Rule 26.02 (1).

> It is well-settled that discovery rules are to be liberally construed so as to provide the parties with relevant information fundamental to proper litigation. While not binding on the Commission, nonetheless, the Commission finds persuasive Kentucky Civil Rule 26.02 (1).

> *In the Matter of: An Examination of the Application of the Fuel Adjustment Clause of Kentucky Utilities Company from November 1, 2004 to October 31 2006,* Case No. 2006-00509, and *In the Matter of: An Examination of the Application of the Fuel Adjustment Clause of Louisville Gas and Electric Company from November 1, 2004 to October 31, 2006,* Case No. 2006-00510, Order, 9 May 2007.

> Kentucky Civil Rule 26.02 (1) states:

> Parties may obtain discovery regarding any matter, not privileged, which is relevant to the subject matter involved in the pending action, whether it relates to the claim or defense of the party seeking discovery or the claim or defense of any other party, including the existence, description, nature, custody, condition and location of any books, documents, or other tangible things and the identity and location of persons having knowledge of any discoverable matter. It is not ground for objection that the information sought will be inadmissible at the trial if the information

> sought appears to reasonably calculated to lead to the discovery of admissible evidence.

The information sought by the Attorney General clearly falls within the scope of permissible inquiry consistent with the authority under Civil Rule 26.02 (1). Further, it is not the Attorney General's burden to prove that the discovery request is proper. Rather, it is the company's burden to demonstrate that the request is exempt from disclosure, and to cite specific grounds in support of its contention.

> Where a party objects to the request, the burden is upon the objecting party to demonstrate that the request is improper. (footnote omitted).
>
> *In the Matter of: The Application of Kentucky-American Water Company for a Certificate of Public Convenience and Necessity Authorizing the Construction of Kentucky River Station II, Associated Facilities and Transmission Main,* Case No. 2007-00134, Order, 15 November 2007.

Moreover, as the Commission has explained:

> As part of a discovery request, the issue is not whether the item is admissible.
>
> *In the Matter of: An Examination of the Application of the Fuel Adjustment Clause of Kentucky Utilities Company from November 1, 2004 to October 31 2006,* Case No. 2006-00509, and *In the Matter of: An Examination of the Application of the Fuel Adjustment Clause of Louisville Gas and Electric Company from November 1, 2004 to October 31, 2006,* Case No. 2006-00510, Order, 9 May 2007.

With regard to question 16, the Attorney General is entitled to the information sought in the opening question based on the aforementioned arguments notwithstanding the fact that the company claims that the request is not "germane," or presumably irrelevant. The company should be required to provide all information it used, or rejected, in determining the EKPC retail rate feasibility study as well as Owen's participation in same, including correspondence between Owen and the consultant and Owen and EKPC. Indeed, it is the feasibility of the rates and the impact on the ratepayers, as in whether they are fair, just and reasonable, that lies at the heart of this litigation.

At questions 31, 32, 60, 67 and 68 the company simply did not answer the opening questions and should be compelled to do so. There was no objection or claim of privilege. Hence, the responses should be immediately provided.

WHEREFORE, the Attorney General respectfully moves the Commission to compel the company to adequately respond to the aforementioned discovery requests immediately. To deny this request will result in denying the Attorney General and the Commission the information they require in reaching informed decisions regarding this matter, and further, it would deny the Attorney General due process and meaningful participation in the instant proceeding.

Respectfully submitted,

JACK CONWAY
ATTORNEY GENERAL

JENNIFER BLACK HANS
DENNIS G. HOWARD, II
LAWRENCE W. COOK
ASSISTANT ATTORNEYS GENERAL
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Certificate of Service and Filing

Counsel certifies that an original and ten photocopies of the foregoing were served and filed by hand delivery to Jeff Derouen, Executive Director, Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40601; counsel further states that true and accurate copies of the foregoing were mailed via First Class U.S. Mail, postage pre-paid, to:

Hon. James M. Crawford
Crawford and Baxter, P.S.C.
523 Highland Avenue
P.O. Box 353
Carrollton, KY 41008

Mark Stallons
President
Owen Electric Cooperative, Inc.
P. O. Box 400
Owenton, KY 40359

this 1st day of August, 2011

Assistant Attorney General

Affiant, Mark A Stallons, states that the answers given by him to the foregoing questions are true and correct to the best of his knowledge and belief.

Mark A Stallons

Subscribed and sworn to before me by the affiant, Mark A Stallons, this 5th day of August, 2011.

Notary Melissa K Moore

State-at-Large

My Commission expires April 14th 2015.

Affiant, James Adkins, states that the answers given by him to the foregoing questions are true and correct to the best of his knowledge and belief.

James Adkins
James Adkins

Subscribed and sworn to before me by the affiant, James Adkins, this 5th day of August, 2011.

Notary Melissa K. Moore
State-at-Large

My Commission expires April 14th, 2015.

OWEN ELECTRIC COOPERATIVE
CASE NO. 2011-00037
SUPPLEMENTAT RESPONSE IN REPLY TO THE ATTORNEY GENERAL'S MOTION TO COMPEL REQUEST

Question:

The report at page 5 states that the company had created a rates task force in August 2009 to develop a request for proposal to hire a consultant to prepare a rate study based on a 2009 test year, and that the results were expected in August 2010. Provide a copy of the request for proposal, together with all responses received.

Response:

Owen disagrees with the Attorney General's statement above relating to "the report at page 5". The report at page 5 actually states: "We are working in unison with East Kentucky Power Cooperative to develop cost of service power supply rates that encourage energy innovation. A rates task force was developed in August of 2009 to develop a Request for Proposal (RFP) to hire a consultant to prepare a cost of service and rate study based upon 2009 test year. The results are expected in August of 2010."

Owen, "the company", did not create the task force, nor did it develop the RFP. As stated in the original response to Question 16 to the Attorney General's Initial Data Request: "EKPC initiated a wholesale and retail rate feasibility study during 2010. EKPC solicited the Requests for Proposals, selected the consultant, and funded the study. The purpose of this feasibility study was to examine the impact of wholesale rate changes on retail rates. Owen participated in the study and provided information concerning its existing rate structure. This information was not filed as part of any proceeding at the Commission and was not used to develop any proposed rate changes at either the wholesale or retail level."

In the interest of attempting to fully respond to the Attorney General's question, Owen has included, in the attached correspondence, a copy of the Request for Proposal ("RFP") provided to Owen by EKPC. Owen does not have in its possession any of the responses received related to this RFP.

OWEN ELECTRIC COOPERATIVE
CASE NO. 2011-00037
SUPPLEMENTAT RESPONSE IN REPLY TO THE ATTORNEY GENERAL'S MOTION TO COMPEL REQUEST

Question a:

Provide copies of any all correspondence to and from the consultant(s) that were retained to conduct such study.

Response a:

Owen maintains that the information requested above is not relevant to the filing in Case No 2011-00037. The filing in this proceeding is based upon a Cost of Service Study prepared for this filing. As stated above, the information contained in the above referenced study was not utilized by Owen for the development of any of the proposed rate changes. However, in the interest of attempting to fully respond to the Attorney General's questions, included in this response is all correspondence, in Owen's possession, relating to the rate feasibility study conducted by EKPC.

b. Question:

Provide copies of any all correspondence to and from EKPC regarding this study.

b. Response:

See attached correspondence and response to Question 16 a above.

c. Question:

Provide copies of any other cost of service studies that were provided to EKPC during the past three (3) years.

c. Response:

Owen has not provided copies of any cost of service studies to EKPC during the past 3 years.

Rebecca Witt

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Friday, August 14, 2009 10:50 AM
To: Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; DAN BREWER - BLUE GRASS; mikew@bgenergy.com; Donald Smothers; Paul Embs (E-mail); David duvall (E-mail); Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); Bill Prather; Wayne Davis (E-mail); Jerry Carter; cperry@fme.coop; jhazelrigg@fme.coop; mbnance@fme.coop; carol.fraley@graysonrecc.com; Don.Combs@Graysonrecc.com; kim.bush@graysonrecc.com; Jim Jacobus (E-mail); Vickie Lay (E-mail); Sheree Gilliam; donschaefer@jacksonenergy.com; Sharon Carson (E-mail); rodneychrisman@jacksonenergy.com; Kerry Howard (E-mail); maudie@lvrecc.com; Sandra Bradley (E-mail); Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; Nicky Rapier; J. Edward Boone (E-mail); debbiem; gay@shelbyenergy.com; denise@shelbyenergy.com; Allen Anderson; Stephen Johnson; Ruby Patterson; Barry Myers (E-mail); John Patterson (E-mail); abeard@tcrecc.com
Cc: Tony Campbell; Jim Lamb; Stacy Barker; Ann Wood; Charlene Creager
Subject: Invitation to a Conference

Ladies and Gentlemen:

I would like to invite you to a conference to be held here at EKPC on August 31, 2009. We will be covering two topics – the Rate Design Feasibility Study that was presented at the August Board meeting and an update on the Real Time Pricing (RTP) Pilot program. The agenda for the conference is:

10:00 – 10:05	Welcome
10:05 – 10:55	Feasibility Discussion – The Three "W"s: Why Do It Now; Why All Of Us; What's The PSC Got To Do With It?
10:55 – 11:05	Break
11:05 – 11:45	Feasibility Discussion – The Scope of Work: Share points from the draft Request for Proposals
11:45 – 12:30	Sack Lunch
12:30 – 01:30	RTP Discussion: August 12th Presentation to PSC Staff; EKPC's Assistance to Member Systems; Things to Think About

The conference will be held in the EKPC Board Room and is scheduled for **August 31, 2009**, starting at **10:00 a.m.** A sack lunch will be provided. Please let me know by **August 27, 2009** if you plan on attending and how many from cooperative will be attending. If you have any questions, please feel free to get in touch with me. Thank you.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Tuesday, September 01, 2009 9:22 AM
To: Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; DAN BREWER - BLUE GRASS; mikew@bgenergy.com; Donald Smothers; Paul Embs (E-mail); David duvall (E-mail); Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); Bill Prather; Wayne Davis (E-mail); Jerry Carter; cperry@fme.coop; jhazelrigg@fme.coop; mbnance@fme.coop; carol.fraley@graysonrecc.com; Don.Combs@Graysonrecc.com; kim.bush@graysonrecc.com; Jim Jacobus (E-mail); Vickie Lay (E-mail); Sheree Gilliam; donschaefer@jacksonenergy.com; Sharon Carson (E-mail); rodneychrisman@jacksonenergy.com; Kerry Howard (E-mail); maudie@lvrecc.com; Sandra Bradley (E-mail); Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; Nicky Rapier; J. Edward Boone (E-mail); debbiem; gay@shelbyenergy.com; denise@shelbyenergy.com; Allen Anderson; Stephen Johnson; Ruby Patterson; Barry Myers (E-mail); John Patterson (E-mail); abeard@tcrecc.com; kcarpenter@fme.coop; Cheryl Thomas; jimadkins25@aol.com
Cc: Tony Campbell; Jim Lamb; Stacy Barker; Ann Wood; Charlene Creager
Subject: UPDATED: Invitation to a Conference

Importance: High

Ladies and Gentlemen:

I would like to invite you to a conference to be held here at EKPC on September 9, 2009. We will be focusing primarily on the Rate Design Feasibility Study that was presented at the August Board meeting. There will also be a brief session concerning an update on the Real Time Pricing (RTP) Pilot program. The agenda for the conference is:

9:30 – 9:35	Welcome
9:35 – 10:15	Feasibility Discussion – The Three "W"s: Why Do It Now; Why All Of Us; What's The PSC Got To Do With It?
10:15 – 10:25	Break
10:25 – 11:30	Feasibility Discussion – The Scope of Work: Share points from the draft Request for Proposals
11:30 – 12:00	RTP Update: Review of August 12th Presentation to PSC Staff; Next Steps
12:00	Sack Lunch

The conference will be held in the EKPC Board Room and is scheduled for **September 9, 2009**, starting at **9:30 a.m.** A sack lunch will be provided. Please let me know by the close of business on **September 3, 2009** if you plan on attending, how many from your cooperative will be attending, and how many will be joining us for the sack lunch. If you have any questions, please feel free to get in touch with me. Thank you.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

Rebecca Witt

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Monday, October 26, 2009 2:45 PM
To: Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; Dan Brewer; Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); Bill Prather; Wayne Davis; pjones@farmersrecc.com; cperry@fme.coop; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; Rodney Chrisman; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; J. Edward Boone (E-mail); randyb@srelectric.com; debbiem; denise@shelbyenergy.com; Farrah Cox; Allen Anderson; Stephen Johnson; Ruby Patterson; Barry Myers (E-mail); John Patterson; abeard@tcrecc.com
Cc: Tony Campbell; Jim Lamb; Ann Wood; jimadkins25@aol.com
Subject: Rate Feasibility Study - Draft RFP Scope of Work
Attachments: RFP-EKPC Rate Feasibillity Study 102609.doc; RFP PotentBid.doc

Ladies and Gentlemen:

Please find attached a copy of the draft request for proposal scope of work section. I would note that the referenced attachments are not included with this attachment. Please review and get any comments or suggestions back to me by the close of business Monday, November 2, 2009.

Also attached is an initial list of potential bidders for this RFP. If there is another firm you believe should be included to receive the RFP, please send me the firm's name. If you have an e-mail contact address for that firm, that would be helpful as well.

If you have any questions, please feel free to contact me. Thank you.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
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EAST KE NTUCKY POWER COOPERATIVE, INC.

WHOLESALE AND RETAIL RATES FEASIBILITY STUDY

REQUEST FOR PROPOSALS FOR CONSULTING SERVICES

Background Information

East Kentucky Power Cooperative, Inc. (EKPC) is a not-for-profit generation and transmission cooperative, headquartered in Winchester, Kentucky, that supplies electric power to 16 member cooperatives and has a limited amount of off-system sales. The member cooperatives are:

Big Sandy Rural Electric Cooperative Corporation (RECC) of Paintsville, Kentucky
Blue Grass Energy Cooperative of Nicholasville, Kentucky
Clark Energy Cooperative of Winchester, Kentucky
Cumberland Valley Electric of Gray, Kentucky
Farmers RECC of Glasgow, Kentucky
Fleming-Mason Energy Cooperative of Flemingsburg, Kentucky
Grayson RECC of Grayson, Kentucky
Inter-County Energy Cooperative of Danville, Kentucky
Jackson Energy Cooperative of McKee, Kentucky
Licking Valley RECC of West Liberty, Kentucky
Nolin RECC of Elizabethtown, Kentucky
Owen Electric Cooperative of Owenton, Kentucky
Salt River Electric Cooperative of Bardstown, Kentucky
Shelby Energy Cooperative of Shelbyville, Kentucky
South Kentucky RECC of Somerset, Kentucky
Taylor County RECC of Campbellsville, Kentucky

EKPC and its member cooperatives are subject to the jurisdiction of the Kentucky Public Service Commission (PSC).

In recent years, there has been an increased interest at the federal and state levels in the development and promotion of energy efficiency and demand-side management (DSM) programs and addressing possible disincentives currently existing within traditional rate regulation. In November 2008 the PSC opened an administrative proceeding to consider new electric energy and natural gas provisions of the federal Energy Independence and Security Act of 2007 (EISA 2007).[1] One of the issues this administrative case will determine is whether Kentucky should implement the new electric energy standard described in Section 532(a)(17) of EISA 2007, which states "The rates allowed to be charged by any electric utility shall (i) align utility incentives with the delivery of cost-effective energy efficiency; and (ii) promote energy efficiency investments."

In recent base rate case decisions the PSC has clearly indicated its support for more energy efficiency and DSM programs.[2] The PSC stated it was very much interested in cost of service based rates and DSM programs that incentivize both the utility and the customers to practice energy efficiency in a cost-effective manner. The PSC has further emphasized similar opinions in the most recent orders in rate applications of some of EKPC's member distribution systems. Specifically, the PSC stated its belief that it was appropriate for the PSC to encourage all electric energy providers to make a greater effort to offer cost-effective DSM and other energy efficiency programs. In addition, the PSC stated that if Owen Electric Cooperative believed after developing its energy innovation plan that its rate design did not support energy efficiency and DSM activities, then it

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[1] Case No. 2008-00408, *Consideration of the New Federal Standards of the Energy Independence and Security Act of 2007*. An electronic version of the case records referenced in this request is available on the Commission's website, www.psc.state.ky.us.

[2] See Case No. 2008-00409, *East Kentucky Power Cooperative, Inc.*, March 31, 2009 Order; Case No. 2008-00254, *Grayson Rural Electric Cooperative Corporation*, June 3, 2009 Order; Case No. 2008-00401, *Big Sandy Rural Electric Cooperative Corporation*, June 3, 2009 Order; Case No. 2008-00030, *Farmers Rural Electric Cooperative Corporation*, June 10, 2009 Order; and Case No. 2008-00154, *Owen Electric Cooperative, Inc.*, June 25, 2009 Order. A copy of the Owen Electric Cooperative Order is attached as Exhibit C.

should consider filing an application to adopt a DSM surcharge or to revise its rate design.

Objectives:

EKPC is seeking services from a consultant to assist EKPC and its member distribution cooperatives in accomplishing the following objectives consistent with the energy standards set out in EISA 2007.

1. The appropriate retail rate designs for electric distribution cooperatives that are compatible and supportive of the new electric energy standard described in Section 532(a)(17) of EISA 2007, on cost-effective energy efficiency and promote energy efficient investments ,
2. The appropriate wholesale rate design for a generation and transmission cooperative that is compatible and supportive of the retail rate designs of the distribution electric cooperatives that support the new electric energy standard described in Section 532(a)(17) of EISA 2007, on cost-effective energy efficiency and promote energy efficient investments , and,
3. The proper time frame and path for the distribution cooperatives and the generation and transmission cooperative to accomplish these tasks.

Project Detail, Scope and Deliverables:

EKPC is fully cognizant of the fact that demand is established at the retail meter while costs to meet that demand begin at the electric generator. With these facts in mind, meeting the above objectives will require tremendous effort and balanced approach on the part of EKPC, its member cooperatives, and the selected consultant. To assist it with this project, EKPC has retained the services of a former pricing EKPC employee in the rates area, Mr. Jim Adkins. The tasks involved will include at a minimum, but not limited to, the following ones:

1. Determine in a very general and generic sense what types of retail rate designs are most compatible and supportive of the new energy standards in EISA 2007.
2. Develop wholesale rate design(s) that are compatible with the retail rate designs suggested in item No. 1 above. These wholesale rates will require the below listed tasks:
    a. Determination of the proper on-peak and off-peak periods by time of day and by time of year.
    b. Determine the proper revenue requirements for the selected test period for EKPC.
    c. Conduct an embedded cost-of-service study ("COSS") for the test period.
    d. Develop wholesale rate designs based on the COSS that are compatible with the generic retail rates supportive of EISA 2007 and that will minimize shifts in revenue requirements from one member cooperative to another member cooperative.
    e. Determine a time frame and a path for the member cooperatives to implement the new wholesale rate designs.
3. Develop retail rate designs for each one of EKPC's sixteen (16) member distribution cooperatives that are compatible with EKPC's wholesale rate design and the energy standards in EISA 2007. These retail rate designs with require the below listed tasks:

a. Conduct an embedded cost-of-service study ("COSS") for the test period for each distribution cooperative. This COSS will include the revenue requirements for each rate class for EKPC's current wholesale rates and proposed wholesale rates

b. Develop retail rate designs for all rate classes for the member cooperative that are compatible and support EISA 2007.

c. Determine a time frame and a path for the member cooperatives to implement the new retail rate designs.

Project Schedule:

EKPC has the following schedule in mind to accomplish this project:

1. Calendar Year 2009 – Test period for the project for EKPC and its member distribution systems
2. February 15, 2010 – Consulting Firm Selected
3. April 13, 2010 – Status Report from Consultant
4. June 8, 2010 – Status Report from Consultant
5. August 31, 2010 – Final Report presented to EKPC

Resources and Data Provided by EKPC and Members:

EKPC and/or member cooperatives will provide the billing data, cost data, financial statements needed and requested by the consulting firm. The consultant will process all of the load research data including retail class contributions to EKPC's coincident demands, retail rate class contributions to individual distribution cooperative coincident peak demands, retail rate class peak demands, and the sum of individual customer's peak demands. This data will be provided for each distribution cooperative for each month of the test period.

EKPC will provide resources that may be of assistance in developing information and data, interpreting assumptions and results and helping to eliminate any bottlenecks that may occur.

Consultant Evaluation Criteria:

The cost of a project is always a factor in the selection of a consulting firm but it is certainly not the only one or the most important one in the selection of a firm for this project. The evaluation criteria for selecting a consulting firm are listed below:

- The firm's overall experience with projects similar in scope, size and complexity with this one.
- The firm's experience with cooperatives - both G&T's and distribution cooperatives.
- The firm's experience in dealing with regulated utilities and regulators.
- The firm's experience in preparing load research data and analysis.
- The experience and expertise of the firm's consulting staff committed to this project.
- The ability to meet the schedule outlined in this RFP.
- The firm's demonstrated understanding of EISA 2007.
- The firm's demonstrated understanding of the rural electric program.
- Completeness and clarity of the work plan.
- The cost of the project.

Consultant's Suggestions and/or Creativity:

In recognition of the fact that consulting firms are made up of experienced professionals capable of conceiving creative alternatives, EKPC and its member distribution cooperatives are willing to entertain proposals from consulting firms that may be different in strategy, approach and scope from what has been laid out in the preceding pages. The following attachments are provided to assist in the development of a response to this RFP and potentially spark some new and creative approaches. Attached as Appendix A to this RFP is a copy of EKPC's wholesale tariff. Attached as Appendix B is the retail tariffs for four distribution cooperatives. Attached as Appendix C is a copy of the Kentucky Public Service Commission's Order in Owen Electric Cooperative's last rate application in Case No. 2008-00154.

Terms and Conditions:

Attached as Appendix D is a copy of the proposed contract that will be executed by EKPC and the selected consultant.

Responses to the Request for Proposals:

The responses from the consultant should address at a minimum the following items:

1. The firm's proposed approach and time schedule, with the time schedule in a detailed schematic form, for this project to ensure completion in the proper time frame.
2. The firm's experience with electric cooperatives including G&T's and distribution cooperatives individually as well as collectively especially in a regulated environment.

3. The firm's experience with revenue requirements, cost-of-service studies, load research, and rate design in general and with cooperatives both the wholesale and retail levels.
4. A listing of the firm's employees that will be a part of this project including their educational background and relevant experience in cost-of-service and rate design projects.
5. The cost of the project.
6. The name of three to five clients for which the consulting firm has completed similar projects and the name of a contact at that client.
7. Disclosure of potential conflicts of interest.
8. A thorough description of the work plan, including an estimate of the number of hours devoted to each task.

The firm should provide ___ bound and ___ unbound copies of its proposal, along with an electronic copy of the proposal on CD.

POTENTIAL BIDDERS LIST
RATE DESIGN FEASBILITY STUDY

Consultant Firm Name	Contact E-mail
Baker Tilly Virchow Krause and Company	thomas.unke@bakertilly.com
Burns and McDonnell	driedel@burnsmcd.com
C. H. Guernsey and Company	michael.moore@chguernsey.com
Overland Consulting, Inc.	hlubow@overlandcounsulting.com
Patterson and Dewar	jbfranklin@pd-engineers.com
The Prime Group, LLC	sseelye@insightbb.com
R. W. Beck	tcorrigan@rwbeck.com
Schumaker and Company	solutions@schuco.com
Shaw Consultants International, Inc.	consulting@shawgrp.com
Vantage Consulting, Inc.	wdrabinski@vantageconsulting.com

Additional potential vendors are welcome. Please provide the firm name and if available an e-mail address. Thank you.

Rebecca Witt

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Wednesday, November 04, 2009 8:42 AM
To: Mark Stallons
Subject: Potential Bidder for RFP - Rate Design Feasibility Study

Mark,

Please excuse this interruption, but I wanted to follow up on an earlier discussion. You had previously mentioned a possible bidder for the rate design RFP. I believe it was an organization called "PSC". Jim Adkins had also suggested including them. Could you give me the correct name of this consultant, and if you have it, an e-mail address we can use to contact them. Thank you.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

√ **Rebecca Witt**

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Wednesday, November 04, 2009 10:52 AM
To: Mark Stallons
Subject: RE: Duane Kexel

I will add him and the firm – thank you.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

-----Original Message-----
From: Mark Stallons [mailto:mstallons@owenelectric.com]
Sent: Wednesday, November 04, 2009 9:23 AM
To: Isaac Scott
Subject: FW: Duane Kexel

Duane is with Power Systems Engineering. I would recommend adding to the rate study bid list.

Mark

√Rebecca Witt

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Monday, November 16, 2009 4:19 PM
To: Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; Dan Brewer; Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); Bill Prather; Wayne Davis; pjones@farmersrecc.com; cperry@fme.coop; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; Rodney Chrisman; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; J. Edward Boone (E-mail); randyb@srelectric.com; debbiem; denise@shelbyenergy.com; Farrah Cox; Allen Anderson; Stephen Johnson; Ruby Patterson; Barry Myers (E-mail); John Patterson; abeard@tcrecc.com
Cc: Tony Campbell; Jim Lamb; Ann Wood; jimadkins25@aol.com
Subject: Rate Feasibility Study - RFP Issued
Attachments: RFP PotentBidIssued.doc

Ladies and Gentlemen:
EKPC issued the RFP for the Rate Feasibility Study this afternoon, November 16, 2009. Responses are due by Noon, December 18, 2009. The RFP was sent to 13 different firms. Attached is a list of the firms the RFP has been sent to. We will update you as this process progresses.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

POTENTIAL BIDDERS LIST
RATE DESIGN FEASBILITY STUDY

Consultant Firm Name
Baker Tilly Virchow Krause and Company
Black and Veatch
Burns and McDonnell
C. H. Guernsey and Company
Gannett Fleming
Overland Consulting, Inc.
Patterson and Dewar
Power System Engineering, Inc.
The Prime Group, LLC
R. W. Beck
Schumaker and Company
Shaw Consultants International, Inc.
Vantage Consulting, Inc.

Rebecca Witt

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Monday, November 23, 2009 11:05 AM
To: Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; DAN BREWER - BLUE GRASS; Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); Bill Prather; Wayne Davis; pjones@farmersrecc.com; Chris Perry; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; Rodney Chrisman; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; J. Edward Boone (E-mail); randyb@srelectric.com; debbiem; denise@shelbyenergy.com; Farrah Cox; Allen Anderson; Stephen Johnson; Ruby Patterson; Barry Myers (E-mail); John Patterson; abeard@tcrecc.com
Cc: Tony Campbell; Jim Lamb; Ann Wood; jimadkins25@aol.com
Subject: East Kentucky Power - Request for Proposal - Wholesale & Retail Rates Feasibility Study
Attachments: FINAL - RFP EKPC Rates Study - UPDATED 11-16-09.doc

Ladies and Gentlemen:

Attached below is a copy of the RFP that was issued on November 16, 2009 for the Rate Design Feasibility Study. Replies are due by Noon, December 18, 2009. The RFP is being coordinated through EKPC's Supply Chain Management process.

<<FINAL - RFP EKPC Rates Study - UPDATED 11-16-09.doc>>

Isaac S. Scott

Manager - Pricing

East Kentucky Power Cooperative, Inc.

4775 Lexington Road

P. O. Box 707

Winchester, Kentucky 40392-0707

859.745.9243

isaac.scott@ekpc.coop

EAST KENTUCKY POWER COOPERATIVE
A Touchstone Energy Cooperative
Supply Chain Management

REQUEST FOR PROPOSAL

Wholesale & Retail Rates Feasibility Study

Issued:
11/16/2009

Proposal Due:
12:00 Noon EST Friday 12/18/2009

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1. PURPOSE

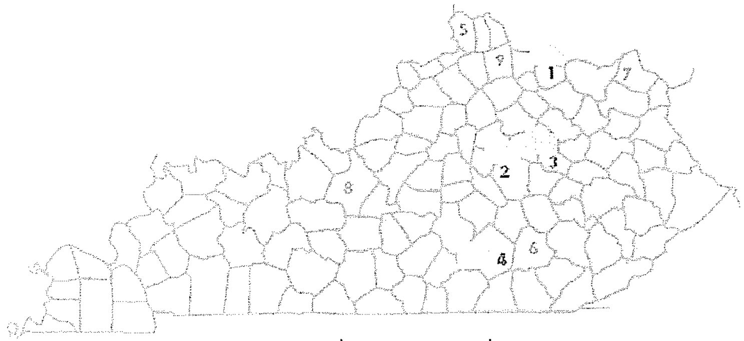
East Kentucky Power Cooperative (EKPC) is seeking proposals from qualified bidders to provide consulting services to develop appropriate wholesale rate design for a generation and transmission cooperative and retail rate designs for electric distribution cooperatives that are compatible and supportive of the standards described in Section 532(a)(17) of the Energy Independence and Security Act of 2007. These standards focus on cost-effective energy efficiency and promote energy efficient investments.

2. About Us

East Kentucky Power Cooperative, Inc. ("East Kentucky Power", "EKPC") is a not-for-profit generation and transmission cooperative owned by 16 rural electric distribution cooperatives (members). Together, EKPC and member cooperatives are known as Kentucky's Touchstone Energy Cooperatives serving over 518,000 homes and businesses in 87 counties of Kentucky. EKPC owns electric generation, transmission and distribution substations and is engaged in the business of generating and transmitting electricity on behalf of its members. EKPC operates a mix of generation capacities including coal, gas, oil, hydro and landfill methane gas, totaling approximately 2,900 MW, 2,800 miles of transmission lines and 350 substations. EKPC maintains 17 warehouses located at four major power plants and its corporate headquarters. EKPC's service territory and the location of its generation facilities are shown below. For additional information, please visit our website at www.ekpc.coop

EAST KENTUCKY POWER GENERATION

1	Spurlock	1,118 net MW
2	Dale	196 net MW
3	Smith Combustion Turbine Units	Summer 626 net MW Winter 842 net MW
4	Cooper	341 net MW
Landfill Gas Plants		
5	Bavarian	3.2 net MW
6	Laurel Ridge	4.0 net MW
7	Green Valley	2.4 net MW
8	Pearl Hollow	2.4 net MW
9	Pendleton	3.2 net MW



shows system-wide service area

EKPC manages the generation and transmission assets for its 16 distribution members/owners:

- Big Sandy RECC
- Blue Grass Energy Cooperative
- Clark Energy Cooperative
- Cumberland Valley Electric
- Farmers RECC
- Fleming-Mason Energy Cooperative
- Grayson RECC
- Inter-County Energy
- Jackson Energy Cooperative
- Licking Valley RECC
- Nolin RECC
- Owen Electric Cooperative
- Salt River Electric Cooperative
- Shelby Energy Cooperative
- South Kentucky Rural Electric
- Taylor County RECC

3. EKPC CONTACT INFORMATION

All questions and responses to this RFP must be emailed concurrently to both contacts listed below. Proposals will be submitted in hard copy via physical mail and PDF format via email. Telephone and/or physical mail (if required) shall be addressed to the primary contact only. No communication with any other EKPC employees related to this RFP is allowable during the solicitation period and until a contract is signed, unless specifically authorized in writing by the contacts listed below. The primary contact will coordinate internally with EKPC operations personnel to address any technical/ operational questions bidders might have. Failure to comply with this requirement will result in disqualification of the respondent. The conduct of bidders during the RFP process will play a part in the evaluation.

Primary Contact:
For email, telephone and physical mail.

Brenda Eames
Sr. Sourcing Agent
East Kentucky Power Cooperative
4775 Lexington Rd
P.O. Box 707
Winchester, KY 40392-0707
brenda.eames@ekpc.coop
859 745-9766 Office
859 737-6043 Fax

Alternate Contact:
For email contact only:

Isaac Scott
Manager, Pricing
East Kentucky Power Cooperative
4775 Lexington Rd
P.O. Box 707
Winchester, KY 40392-0707
Isaac.scott@ekpc.coop
859 745-9243

4. RFP Conditions

1) All information in this RFP is the intellectual property of EKPC and should be treated as such. In addition, the information contained in any resulting contract from this solicitation is regarded as confidential and is not to be disclosed beyond the parties directly involved without the express written consent of EKPC.
2) In protecting bidder's confidential or proprietary information, such information must be clearly marked as being confidential and proprietary.
3) EKPC's answers to a bidder's questions will be shared to all bidders as appropriate.
4) EKPC reserves the right to accept and/or reject any and all proposals. Bidder may not claim any indemnity, nor may bidder contest for whatever reason, the choice made by EKPC.
5) EKPC is not under any obligation to award a contract and reserves the right to terminate the Request for Proposal process at any time, and to withdraw from discussions with any or all of the bidders who have responded.
6) All proposals will be considered final. No additions, deletions, corrections or adjustments will be accepted after the proposal due date unless mutually agreed between the parties.
7) This RFP shall not be construed as an authorization to perform development work at the expense of EKPC. Any development work performed or any expenses made by a bidder in order to respond to this RFP will be at the discretion and sole responsibility of the bidder. EKPC will not reimburse any expenses incurred by the bidder as a result of the bidder's participation in this solicitation. This RFP does not represent a commitment to purchase.
8) Bidder's offer must be firm for a period of ninety (90) days from the date responses are due to EKPC. EKPC will be using a weighted method to evaluate proposals. In addition, EKPC reserves the right and flexibility to negotiate with multiple bidders to arrive at a mutually agreeable relationship.
9) Bidder shall refrain from any publicity regarding this RFP or the contents thereof. Bidder shall not release any information to newspapers, magazines, journals or any other medium about the acceptance of the tender or the award of the contract without the prior written approval of EKPC.
10) The Consulting and Services Agreement (CSA) shown in Part II of this RFP will form the basis for doing business between EKPC and the winning bidder. This RFP and bidder's proposal will be included and made part of the resulting contract. A Consulting and Services Agreement must be executed prior to commencement of any work. No obligations on the part of EKPC will be incurred until a satisfactory contract has been executed and accepted by both parties.
11) An authorized officer of the company submitting the proposal must sign all proposals.
12) Any conditions of this RFP, which cannot be fulfilled, are to be clearly stated in bidder's proposal.

5. Bid Process & Contracting Timeline

Process and Milestones	Dates
Invitation to bid & issuance of RFP	Monday 11/16/2009
Proposals due to EKPC by 12:00 Noon EST. Please email your proposals in PDF format to the EKPC contacts previously identified. Hard copies of your proposal must be received by EKPC by the same deadline. Pricing must be in a separate document but sent under the same transmittal. Please use the following convention for naming your document files: "Proposal - Xxxx - EKPC", "Pricing - Xxxx - EKPC", where Xxxx is bidder's company name	Friday 12/18/2009
EKPC conducting proposal evaluations, checking references, and identifying finalists. During the evaluation period, bidder is asked to be readily available by phone for any needed follow-ups.	12/18/2009 – 01/12/2010
Award of contract	01/15/2010
Sign contract	01/19/2010
Beginning date of new contract	02/01/2010
Final Report to EKPC	07/31/2010
End of contract	TBD

6. Scope of Work & Specifications

Background:

EKPC and its member cooperatives are subject to the jurisdiction of the Kentucky Public Service Commission (PSC).

In recent years, there has been an increased interest at the federal and state levels in the development and promotion of energy efficiency and demand-side management (DSM) programs and addressing possible disincentives currently existing within traditional rate regulation. In November 2008 the PSC opened an administrative proceeding to consider new electric energy and natural gas provisions of the federal Energy Independence and Security Act of 2007 (EISA 2007).[1] One of the issues this administrative case will determine is whether Kentucky should implement the new electric energy standard described in Section 532(a)(17) of EISA 2007, which states "The rates allowed to be charged by any electric utility shall (i) align utility incentives with the delivery of cost-effective energy efficiency; and (ii) promote energy efficiency investments."

In recent base rate case decisions the PSC has clearly indicated its support for more energy efficiency and DSM programs.[2] The PSC stated it was very much interested in cost of service based rates and DSM programs that incentivize both the utility and the customers to practice energy efficiency in a cost-effective manner. The PSC has further

[1] Case No. 2008-00408, *Consideration of the New Federal Standards of the Energy Independence and Security Act of 2007*. An electronic version of the case records referenced in this request is available on the PSC's website, http://www.psc.state.ky.us/.

[2] See Case No. 2008-00409, *East Kentucky Power Cooperative, Inc.*, March 31, 2009 Order; Case No. 2008-00254, *Grayson Rural Electric Cooperative Corporation*, June 3, 2009 Order; Case No. 2008-00401, *Big Sandy Rural Electric Cooperative Corporation*, June 3, 2009 Order; Case No. 2008-00030, *Farmers Rural Electric Cooperative Corporation*, June 10, 2009 Order; and Case No. 2008-00154, *Owen Electric Cooperative, Inc.*, June 25, 2009 Order.

emphasized similar opinions in the most recent orders in rate applications of some of EKPC's member distribution systems. Specifically, the PSC stated its belief that it was appropriate for the PSC to encourage all electric energy providers to make a greater effort to offer cost-effective DSM and other energy efficiency programs. In addition, the PSC stated that if Owen Electric Cooperative believed after developing its energy innovation plan that its rate design did not support energy efficiency and DSM activities, then it should consider filing an application to adopt a DSM surcharge or to revise its rate design.

Objectives:

EKPC is seeking services from a consultant to assist EKPC and its member distribution cooperatives in accomplishing the following objectives consistent with the energy standards set out in EISA 2007:

1. The appropriate retail rate designs for electric distribution cooperatives that are compatible and supportive of the new electric energy standard described in Section 532(a)(17) of EISA 2007, on cost-effective energy efficiency and promote energy efficient investments ,
2. The appropriate wholesale rate design for a generation and transmission cooperative that is compatible and supportive of the retail rate designs of the distribution electric cooperatives that support the new electric energy standard described in Section 532(a)(17) of EISA 2007, on cost-effective energy efficiency and promote energy efficient investments, and,
3. The proper time frame and path for the distribution cooperatives and the generation and transmission cooperative to accomplish these tasks.

<u>Project Detail, Scope and Deliverables:</u>

EKPC is fully cognizant of the fact that demand is established at the retail meter while costs to meet that demand begin at the electric generator. With these facts in mind, meeting the above objectives will require tremendous effort and balanced approach on the part of EKPC, its member cooperatives, and the selected consultant. To assist it with this project, EKPC has retained the services of a former pricing EKPC employee in the rates area, Mr. Jim Adkins. Mr. Adkins will be working for EKPC and be assisting in the review, analysis, and oversight of this project. The tasks involved will include at a minimum, but not be limited to, the following:

1. Determine in a very general and generic sense what types of retail rate designs are most compatible and supportive of the new energy standards in EISA 2007.
2. Develop wholesale rate design(s) that are compatible with the retail rate designs suggested in item No. 1 above. These wholesale rates will require the below listed tasks:
    a. Determine the proper on-peak and off-peak periods by time of day and by time of year.
    b. Determine the proper revenue requirements for the selected test period for EKPC.
    c. Conduct an embedded cost-of-service study ("COSS") for the test period.
    d. Develop wholesale rate designs based on the COSS that are compatible with the generic retail rates supportive of EISA 2007 and that will, to the extent practical, minimize shifts in revenue requirements from one member cooperative to another member cooperative.

e. Determine a time frame and a path for the member cooperatives to implement the new wholesale rate designs.

3. Develop retail rate designs for each one of EKPC's sixteen (16) member distribution cooperatives that are compatible with EKPC's wholesale rate design and the energy standards in EISA 2007. These retail rate designs will require the below listed tasks:
   a. Conduct an embedded cost-of-service study ("COSS") for the test period for each distribution cooperative. This COSS will include the revenue requirements for each rate class for EKPC's current wholesale rates and proposed wholesale rates
   b. Develop retail rate designs for all rate classes for the member cooperative that are compatible and support EISA 2007.
   c. Determine a time frame and a path for the member cooperatives to implement the new retail rate designs.
4. In the event the wholesale or retail COSS or the wholesale or retail rate designs are included in a base rate case proceeding before the PSC, prepare testimony supporting the COSS or rate designs, respond to data requests from the PSC or intervenors, and be available to provide expert testimony at any hearing before the PSC.

Project Schedule:

EKPC has the following schedule in mind to accomplish this project:

Calendar Year 2009 – Test period for the project for EKPC and its member distribution systems

1. January 15, 2010 – Consulting Firm Selected
2. March 12, 2010 – Status Report from Consultant
3. May 10, 2010 – Status Report from Consultant
4. July 31, 2010 – Final Report presented to EKPC

Resources and Data Provided by EKPC and Members:

EKPC and/or member cooperatives will provide the billing data, cost data, financial statements needed and requested by the consulting firm. The consultant will process all of the load research data including retail class contributions to EKPC's coincident demands, retail rate class contributions to individual distribution cooperative coincident peak demands, retail rate class peak demands, and the sum of individual customer's peak demands. This data will be provided for each distribution cooperative for each month of the test period.

EKPC will provide resources that may be of assistance in developing information and data, interpreting assumptions and results and helping to eliminate any bottlenecks that may occur.

Consultant Evaluation Criteria:

The cost of a project is always a factor in the selection of a consulting firm but it is certainly not the only one or the most important one in the selection of a firm for this project. The evaluation criteria for selecting a consulting firm are listed below:

- The firm's overall experience with projects similar in scope, size and complexity.
- The firm's experience with cooperatives - both G&T's and distribution cooperatives.
- The firm's experience in dealing with regulated utilities and regulators.

- The firm's experience in preparing load research data and analysis.
- The experience and expertise of the firm's consulting staff committed to this project.
- The ability to meet the schedule outlined in this RFP.
- The firm's demonstrated understanding of EISA 2007.
- The firm's demonstrated understanding of the rural electric program.
- Completeness and clarity of the work plan.
- The cost of the project.

Consultant's Suggestions and/or Creativity:

In recognition of the fact that consulting firms are made up of experienced professionals capable of conceiving creative alternatives, EKPC and its member distribution cooperatives are willing to entertain proposals from consulting firms that may be different in strategy, approach and scope from what has been laid out in the preceding pages. The following links to the PSC website are provided to assist in the development of a response to this RFP and potentially spark some new and creative approaches.

EKPC's wholesale tariff:

http://www.psc.state.ky.us/tariffs/Electric/East%20Kentucky%20Power%20Cooperative,%20Inc/Tariff.pdf

Retail tariff – Blue Grass Energy Cooperative:

http://www.psc.state.ky.us/tariffs/Electric/Bluegrass%20Energy%20Coop.%20Corp/Tariff.pdf

Retail tariff – Owen Electric Cooperative:

http://www.psc.state.ky.us/tariffs/Electric/Owen%20Electric%20Cooperative,%20Inc/Tariff.pdf

Retail tariff – Salt River Electric Cooperative:

http://www.psc.state.ky.us/tariffs/Electric/Salt%20River%20Electric%20Coop.%20Corp/Tariff.pdf

Retail tariff – South Kentucky RECC:

http://www.psc.state.ky.us/tariffs/Electric/South%20Kentucky%20RECC/Tariff.pdf

PSC Order in Case No. 2008-00154 – Owen Electric Cooperative:

http://www.psc.state.ky.us/order_vault/Orders_2009/200800154_06252009.PDF

Responses to the Request for Proposals:

The responses from the consultant should address at a minimum the following items:

1. The firm's proposed approach and time schedule, with the time schedule in a detailed schematic form, for this project to ensure completion in the proper time frame.
2. The firm's experience with electric cooperatives including G&T's and distribution cooperatives individually as well as collectively especially in a regulated environment.
3. The firm's experience with revenue requirements, cost-of-service studies, load research, and rate design in general and with cooperatives both the wholesale and retail levels.
4. A listing of the firm's employees that will be a part of this project including their educational background and relevant experience in cost-of-service and rate design projects.
5. The cost of the project.
6. The name of three to five clients for which the consulting firm has completed similar projects and the name of a contact at that client.

7. Disclosure of potential conflicts of interest.

8. A thorough description of the work plan, including an estimate of the number of hours devoted to each task.

9. A thorough description of the firm's experience of appearing as an expert witness before state regulatory commissions in a base rate case proceeding. Include as a separate schedule an hourly quote and associated cost rates for witness services related to the COSS and rate design proposals.

The firm should provide 4 bound and 1 unbound hard copies of its proposal, along with an electronic copy in PDF format of the proposal on CD.

7. STRUCTURE OF RESPONSE

Bidders are requested to adopt the following response structure:

1) Executive Summary

High level summary of the bidder's offering pertaining to the RFP.

2) Work Approach & Plan

Describe bidder's approach and plan to accomplishing the Work as specified in the RFP.

3) Company & Personnel Information

General Information of Bidder's Company

- ❒ Legal company name and address
- ❒ Dun & Bradstreet number
- ❒ NAICS number (information may be found at www.naics.com)
- ❒ Organizational structure including parent, subsidiary and partnership relationships
- ❒ Qualifications and experience
- ❒ Financial status for current and previous three years
- ❒ Risk factors including any pending bankruptcy filings or litigations

Project Personnel

- ❒ Name and title of key personnel directly involved in this project
- ❒ Name and title of highest ranking executive accountable for the successful performance of this project for EKPC

4) References

Provide at least three customer references to whom you provided a similar service. References to include a brief description, location of work, year in which work was completed, contact name, title, phone and/or email.

5) Exceptions to the RFP

List any and all commercial and technical exceptions to the RFP requirements. Exceptions identified shall not constitute acceptance by EKPC. Indicate "No Exceptions Taken" if none is taken.

PART II
CONSULTING AND SERVICES AGREEMENT TEMPLATE

CONSULTING AND SERVICES AGREEMENT

This agreement ("Agreement") is entered into, to be effective as of ______________ ("Effective Date"), by and between EAST KENTUCKY POWER COOPERATIVE, INC. headquartered at 4775 Lexington Road, Winchester, Kentucky 40391 ("EKPC"), and ______________________________________ ______________________________________ ("Consultant").

The parties agree as follows:

1. Consultant Services. Consultant agrees to provide the services as set forth on an Exhibit A (sequentially numbered) in the form of the Exhibit A attached hereto or in other statements of work containing substantially similar information and identified as an Exhibit A (the "Services").

2. Subcontracts. Consultant shall not enter into any subcontracts for the performance of the Services, or assign or transfer any of its rights or obligations under this Agreement, without EKPC's prior written consent and any attempt to do so shall be void and without further effect.

3. Term and Termination; Time is of the Essence. This Agreement is legally binding as of the Effective Date, and, unless terminated as provided herein, shall continue until terminated by EKPC. EKPC may terminate this Agreement or any Exhibit A, in whole or in part, at any time for any reason upon written notice to Consultant.

4. EKPC Resources. Where EKPC provides resources (including but not limited to computers) to Consultant that are reasonably required for the exclusive purpose of providing the Services, Consultant agrees to keep such resources in good order and not permit waste (ameliorative or otherwise) or damage to the same. Consultant shall return the resources to EKPC in substantially the same condition as when Consultant began using the same, ordinary wear and tear excepted.

5. Fees and Billing Procedures. EKPC agrees to pay Consultant for the Services in accordance with the fee(s) set forth in the applicable Exhibit A. Any sum due Consultant for Services performed for which payment is not otherwise specified shall be due and payable sixty (60) days after receipt by EKPC of an invoice from Consultant. Consultant shall only work the number of hours or days as specified in an Exhibit A, unless otherwise expressly approved in advance by EKPC. Unless otherwise provided for under an Exhibit A, Consultant shall bill to EKPC the sums due pursuant to an Exhibit A by Consultant's invoice, which shall contain: (a) EKPC purchase order number, if any, and invoice number; (b) a description of Services rendered; (c) the fee or portion thereof that is due; (d) the number of hours or days worked; (e) travel and living expenses, if any; (f); taxes, if any; and, (g) total amount due. Unless otherwise specified by EKPC, Consultant shall forward invoices in hardcopy format to EKPC, PO Box 707, Winchester, Kentucky 40392-0707 ATTN: ______________________________.

6. Expenses. Where previously approved by EKPC, upon submission of an expense report and receipts, EKPC shall reimburse Consultant for reasonable travel and living expenses consistent with EKPC's then current expense guidelines actually incurred in connection with the Services.

7. Credits. Any amounts due from Consultant may be applied by EKPC against any fees due to Consultant. Any such amounts that are not so applied shall be paid to EKPC by Consultant within sixty (60) days following EKPC's request.

8. Non-binding Terms. Any terms and conditions that are included in a Consultant invoice shall be deemed to be solely for the convenience of the parties, and no such term or condition shall be binding upon EKPC.

9. Auditable Records; Dispute Resolution. Consultant shall maintain accurate records of all fees billable to, and payments made by, EKPC in a format that will permit audit by EKPC for a period of not less than three (3) years. This Section shall survive the termination of this Agreement.

10. Taxes. Consultant represents and warrants that it is an independent contractor for purposes of federal, state, and local employment taxes. Consultant agrees that EKPC is not responsible to collect or withhold any such taxes, including income tax withholding and social security contributions, for Consultant. Any and all taxes, interest or penalties, including any federal, state, or local withholding or employment taxes, imposed, assessed, or levied as a result of this Agreement shall be paid or withheld by Consultant.

11. Non-Disclosure of Confidential Information. The parties acknowledge that each party may be exposed to or acquire communication or data of the other party that is confidential, privileged communication not intended to be disclosed to third parties. For the purposes of this Agreement, the term "Confidential Information" shall mean all information and documentation of a party that: (a) has been marked "confidential" or with words of similar meaning, at the time of disclosure by such entity; (b) if disclosed orally or not marked "confidential" or with words of similar meaning, was subsequently summarized in writing by the disclosing entity and marked "confidential" or with words of similar meaning; or, (c) any Confidential Information derived from information of a party. The term "Confidential Information" does not include any information or documentation that was: (a) already in the possession of the receiving entity without an obligation of confidentiality; (b) developed independently by the receiving entity, as demonstrated by the receiving entity, without violating the disclosing entity's proprietary rights; (c) obtained from a source other than the disclosing entity without an obligation of confidentiality; or, (d) publicly available when received, or thereafter became publicly available (other than through any unauthorized disclosure by, through or on behalf of, the receiving entity).

12. Obligation of Confidentiality. The parties agree to hold all Confidential Information in strict confidence and not to copy, reproduce, sell, transfer, or otherwise dispose of, give or disclose such Confidential Information to third parties other than employees, agents, or subcontractors of a party who have a need to know in connection with this Agreement. The parties agree to advise and require their respective employees, agents, and subcontractors of their obligations to keep such information confidential.

13. Cooperation to Prevent Disclosure of Confidential Information. Each party shall use its best efforts to assist the other party in identifying and preventing any unauthorized use or disclosure of any Confidential Information. Each party shall advise the other party immediately in the event either party has reason to believe that any person who has had access to Confidential Information has violated or intends to violate the terms of this Agreement and each party will cooperate with the other party in seeking injunctive or other equitable relief against any such person.

14. Remedies for Breach of Obligation of Confidentiality. Consultant acknowledges that breach of Consultant's obligation of confidentiality may give rise to irreparable injury to EKPC, which damage may be inadequately compensable in the form of monetary damages. Accordingly, EKPC may seek and obtain injunctive relief against the breach or threatened breach, in addition to any other legal remedies which may be available.

The provisions of this Section shall survive the termination of this Agreement.

15. Work Product. EKPC and Consultant each acknowledge that performance of this Agreement may result in the discovery, creation, or development of inventions, methods, formulae, techniques, processes, improvements, strategies, and data and original works of authorship, in whatever form, first produced or created by or for Consultant as a result of or related to the performance of the Services (the "Work Product"). Consultant agrees that, whether or not the Services are considered works made for hire or an employment to invent, all Work Product shall be the sole property of EKPC. Except as set forth in writing and signed by both EKPC and Consultant, Consultant agrees that EKPC shall have all copyright and patent rights with respect to any Work Product, without regard to the origin of the Work Product. If and to the extent that Consultant may, under applicable law, be entitled to claim any ownership interest in the Work Product, Consultant hereby transfers, grants, conveys, assigns, and relinquishes exclusively to EKPC any and all right, title, and interest it now has or may hereafter acquire in and to the Work Product under patent, copyright, trade secret, and trademark law in perpetuity or for the longest period otherwise permitted by law. Consultant further agrees as to the Work Product to assist EKPC in every reasonable way to obtain

and, from time to time, enforce patents, copyrights, trade secrets, and other rights and protection relating to said Work Product. The provisions of this Section shall survive the termination of this Agreement.

16. Surrender of Materials upon Termination. Upon termination of this Agreement, in whole or in part, Consultant shall immediately return to EKPC all copies of properties received from EKPC, or created or received by Consultant on behalf of EKPC, and which are related to the terminated portion of this Agreement.

17. Mutual Representations and Warranties. Each of EKPC and Consultant represent and warrant that:

- It is duly licensed, authorized, or qualified to do business and is in good standing in every jurisdiction in which a license, authorization, or qualification is required for the ownership or leasing of its assets or the transaction of business of the character transacted by it.
- The execution, delivery, and performance of this Agreement has been duly authorized by it and this Agreement constitutes the legal, valid, and binding agreement of it and is enforceable against it in accordance with its terms.
- It has all requisite power, financial capacity, and authority to execute, deliver, and perform its obligations under this Agreement.
- It shall comply with all applicable federal, state, local, international, or other laws and regulations applicable to the performance by it of its obligations under this Agreement and shall obtain all applicable permits and licenses required of it in connection herewith.
- There is no outstanding litigation, arbitrated matter or other dispute to which it is a party which, if decided unfavorably to it, would reasonably be expected to have a potential or actual material adverse effect on its ability to fulfill its obligations under this Agreement.

18. Representations and Warranties by Consultant. Consultant represents and warrants that:

- Consultant is possessed of superior knowledge with respect to the Services and is aware that EKPC is relying on Consultant's skill and judgment in providing the Services to EKPC.
- the Services will conform to any applicable scope of work; and any materials supplied in connection therewith shall be new, unused, and free from defect;
- the Services will be suitable for the purposes specified by EKPC and will conform to each statement, representation, and description made by Consultant to EKPC;
- the Services are not and shall not be subject to any encumbrance, lien, security interest, patent, copyright or trademark claims, infringements, or other defects in title; and
- any labor or services performed pursuant to this Agreement shall be performed in a competent, diligent, and timely manner in accordance with the highest professionally accepted standards.

Consultant shall respond in writing to any warranty claim by EKPC within five (5) business days of the delivery of notice of such claim to Consultant.

19. General Indemnity. Consultant agrees to indemnify, defend, and hold EKPC, its officers, directors, agents, and employees (an "Indemnitee") harmless from and against any and all liabilities, damages, losses, expenses, claims, demands, suits, fines, or judgments (collectively "Claims"), including reasonable attorneys' fees, costs, and expenses incidental thereto, which may be suffered by, accrued against, charged to, or recoverable from any EKPC Indemnitee, by reason of any Claim arising out of or relating to any act, error or omission, or misconduct of Consultant during the performance of this Agreement.

20 Indemnification Procedures. Promptly after receipt by EKPC of a threat of any action, or a notice of commencement, or filing of any action against an Indemnitee, EKPC shall give notice thereof to Consultant, provided that failure to give or delay in such notice shall not relieve Consultant of any liability it may have to an Indemnitee. EKPC shall not independently defend or respond to any such claim; provided, however, that EKPC may defend or respond to any such claim, at Consultant's expense, if EKPC determines that such defense or response is necessary to preclude a default judgment from being entered against EKPC. Consultant shall have sole control of the defense and of all negotiations for settlement of such action. At Consultant's request, EKPC shall cooperate with Consultant in defending or settling any

such action; provided, however, that Consultant shall reimburse EKPC for all reasonable out-of-pocket costs incurred by EKPC (including, without limitation, reasonable attorneys' fees and expenses).

21. Limitation of Liability. NOTWITHSTANDING ANY OTHER PROVISION SET FORTH HEREIN, NEITHER PARTY SHALL BE LIABLE FOR ANY INDIRECT, SPECIAL, AND/OR CONSEQUENTIAL DAMAGES, ARISING OUT OF OR IN CONNECTION WITH THIS AGREEMENT; PROVIDED, HOWEVER, THAT THE FOREGOING EXCULPATION OF LIABILITY SHALL NOT APPLY WITH RESPECT TO DAMAGES INCURRED AS A RESULT OF THE GROSS NEGLIGENCE OR WILFUL MISCONDUCT OF A PARTY.

22. Insurance. Consultant shall procure and maintain in full force and effect during the term of this Agreement, policies of insurance, of the types and in the minimum amounts stated in the attached Exhibit B. Consultant shall cause the liability it assumed under this Agreement to be specifically insured under the contractual liability section of the liability insurance policies. The liability policy shall be primary without right of contribution from any insurance by EKPC. Consultant shall provide EKPC with certificates of insurance evidencing all of the required coverage.

23. General.

- Relationship between EKPC and Consultant. Consultant represents and warrants that it is an independent contractor with no authority to bind or to commit EKPC to any agreement of any kind or to assume any liabilities of any nature in the name of or on behalf of EKPC. Under no circumstances shall Consultant hold itself out as or be considered an agent, employee, joint venture, or partner of EKPC. In recognition of Consultant's status as independent contractor, EKPC shall carry no Workers' Compensation insurance or any health or accident insurance to cover Consultant, if any. EKPC shall not pay any contributions to Social Security, unemployment insurance, federal or state withholding taxes, any other applicable taxes whether federal, state, or local, nor provide any other contributions or benefits which might be expected in an employer-employee relationship.
- Governing Law. Consultant hereby consents and submits to the jurisdiction and forum of the state and federal courts in the Commonwealth of Kentucky in all questions and controversies arising hereunder.
- Compliance with Laws; EKPC Policies and Procedures. Both parties agree to comply with all applicable federal, state, and local laws, executive orders and regulations issued, where applicable. Consultant shall comply with EKPC policies and procedures, including but not limited to, those related to safety where the same are posted, conveyed, or otherwise made available to Consultant. Without limiting Consultant's other obligations of indemnification herein, Consultant shall defend, indemnify, and hold EKPC Indemnitees harmless from and against any and all Claims, including reasonable expenses suffered by, accrued against, or charged to or recoverable from any EKPC Indemnitee, on account of the failure of Consultant to perform its obligations imposed herein.
- Training and Hazards. Consultant shall furnish adequate numbers of trained, qualified, and experienced personnel and appropriate safety and other equipment in first-class condition, suitable for performance of the Services. Such personnel shall be skilled and properly trained to perform the Services and recognize all hazards associated with the Services. Without limiting the foregoing, Consultant shall participate in any safety orientation or other of EKPC's familiarization initiatives related to safety and shall strictly comply with any monitoring initiatives as determined by EKPC. Consultant shall accept all equipment, structures, and property of EKPC as found and acknowledges it has inspected the property, has determined the hazards incident to working thereon or thereabouts, and has adopted suitable precautions and methods for the protection and safety of its employees and the property. No person performing work for Consultant will perform any of the Services while under the influence of drugs or alcohol.
- Force Majeure. Neither party shall be liable for delays or any failure to perform under this Agreement due to causes beyond its reasonable control. Such delays include, but are not limited to, fire, explosion, flood or other natural catastrophe, governmental legislation, acts, orders, or regulation, strikes or labor difficulties, to the extent not occasioned by the fault or negligence of the delayed party. Any such excuse for delay shall last only as long as the event remains beyond

the reasonable control of the delayed party. However, the delayed party shall use its best efforts to minimize any such delays. The delayed party must notify the other party promptly upon the occurrence of any such event, or performance by the delayed party will not be considered excused hereunder, and inform the other party of its plans to resume performance.

- Advertising and Publicity. Consultant shall not refer to EKPC directly or indirectly in any advertisement, news release, or publication without prior written approval from EKPC.
- No Waiver. The failure of a party to require performance by the other party of any provision herein shall in no way affect that party's right to enforce such provisions or any further breach of the same.
- Notices. Any notice given pursuant to this Agreement shall be in writing and shall be given by personal service or by United States certified mail, return receipt requested, postage prepaid to the addresses indicated herein, or as changed through written notice to the other party. Notice given by personal service shall be deemed effective on the date it is delivered to the addressee, and notice mailed shall be deemed effective on the third day following its placement in the mail addressed to the addressee.
- Entire Agreement. This Agreement and its attached exhibits constitute the entire agreement between the parties and supersede any and all previous representations, understandings, or agreements between EKPC and Consultant as to the subject matter hereof. This Agreement may only be amended by an instrument in writing signed by the parties.
- Cumulative Remedies. All rights and remedies of EKPC herein shall be in addition to all other rights and remedies available at law or in equity, including specific performance against Consultant for the enforcement of this Agreement, and temporary and permanent injunctive relief.

24. Equal Employment Opportunity. To the extent applicable, Contractor shall comply with all of the following provisions, which are incorporated herein by reference: (i) Equal Opportunity regulations set forth in 41 CFR § 60-1.4(a) and (c), prohibiting employment discrimination against any employee or applicant because of race, color, religion, sex, or national origin; (ii) Vietnam Era Veterans Readjustment Assistance Act regulations set forth in 41 CFR § 60-250.4 relating to the employment and advancement of disabled veterans and Vietnam era veterans; (iii) Rehabilitation Act regulations set forth in 41 CFR § 60-741.4 relating to the employment and advancement of qualified disabled employees and applicants for employment; (iv) the clause known as "Utilization of Small Business Concerns and Small Business Concerns Owned and Controlled by Socially and Economically Disadvantaged Individuals" set forth in 15 USC § 637(d)(3); and (v) the subcontracting plan requirement set forth in 15 USC § 637(d).

Executed on the dates set forth below by the undersigned authorized representative(s) of EKPC and Consultant to be effective as of the Effective Date.

Consultant	**EKPC**
By:	By:
Printed Name:	Printed Name:
Title:	Title:
Date:	Date:

EXHIBIT A-1

Consultant's Statement of Work

This Exhibit A – Consultant's Statement of Work dated ________________ ("Start Date") shall be incorporated in and governed by the terms of that certain Consulting and Services Agreement by and between EAST KENTUCKY POWER COOPERATIVE, INC. ("EKPC") and CONSULTANT (the "Agreement"). Unless expressly provided for herein, in the event of a conflict between the provisions contained in the Agreement and those contained herein, the provisions contained in the Agreement shall prevail.

Description of Services:	
Actual Customer (where applicable):	
Schedule / Date of Services:	
Work Product to Be Developed for EKPC (If Any):	
Consultant Rate:	

Approved by Consultant: **Approved by EKPC:**

By	Date	Project Manager	Date
Printed Name		Supervisor	Date
Title		Manager	Date

Consultant's Insurance Obligation

Consultant shall provide and maintain, and shall require any and all subcontractors to provide and maintain, with an insurance company authorized to do business in the Commonwealth of Kentucky and otherwise acceptable to EKPC the following insurance:

a) **Workers Compensation and Employer's Liability Policy**: Prior to the start of the Work, Consultant shall submit evidence of Consultant's Workers' Compensation and Employer's Liability Insurance Policy, and each such policy shall include:
   1) Workers' Compensation (statutory benefits coverage) Insurance in accordance with the laws of the Commonwealth of Kentucky
   2) Employer's Liability with a minimum limit of One Million Dollars ($1,000,000) with respect to Bodily Injury Each Accident/($1,000,000) Bodily Injury by Disease Each Employee/($1,000,000) Bodily Injury by Disease Policy Limit.
   3) United States Longshoremen and Harbor Workers Act Endorsement (WC 00 01 06); if exposures warrant.
   4) Maritime "Jones Act" Endorsement (WC 00 02 01); if exposures warrant.
   5) Federal Employer's Liability Act Endorsement "FELA" (WC 00 01 04); if exposures warrant.
   6) Federal Coal Mine Health and Safety Act Coverage Endorsement (WC 00 01 02); if exposures warrant.

b) **Commercial General Liability Policy**: Prior to the start of Work, Consultant shall provide evidence of Consultant's Policy providing Commercial General Liability Insurance, with combined single minimum limit for bodily injury and property damage of One Million Dollars ($1,000,000) each Occurrence/Two Million Dollars ($2,000,000) General Aggregate and the following coverages:
   1) Coverage for premises and operations, including Work let or sublet.
   2) No exclusion of coverage for Blanket Contractual Liability to the extent covered by the policy against liability assumed by Contractor under this Contract.
   3) No exclusion for Broad Form Property Damage hazard.
   4) No exclusion for liability arising out of blasting, collapse, and underground property damage hazards.
   5) Products and Completed Operations Liability Coverage with a Two Million Dollars ($2,000,000) Aggregate Limit. Said coverage must continue in force for a minimum of two (2) years from the Acceptance of Work.
   6) Personal and Advertising Injury Liability coverage with a One Million Dollar ($1,000,000) Limit and Contractual Liability Exclusion (#5) eliminated.
   7) Said policy shall name EKPC as an Additional Insured to the extent necessary to fulfill Consultant's indemnity obligations under this agreement, with Consultant's policy deemed to be primary.
   8) Said policy shall be endorsed to provide that the underwriter(s) have waived their Rights of Recovery Against Others (subrogation) against EKPC and EKPC's insurance carrier(s).
   9) Coverage shall be amended to provide for Aggregate Limit of Liability at each project or jobsite.
   10) Should policy contain a deductible clause for bodily injury or property damage liability, said deductible shall be shown on the Certificate of Insurance, and Consultant's carrier shall agree to pay any such claims "first dollar" and then recover the deductible amount from Consultant.

c) **Commercial Automobile Liability Insurance Policy**: Prior to the start of Work, Contractor shall provide evidence of Consultant's Commercial Automobile Liability Insurance Covering the use of all owned, non-owned and hired automobiles, with a minimum combined single limit for bodily injury and property damage of One Million Dollars ($1,000,000) each Accident with respect to Consultant's vehicles assigned to or used in performance of Work under this Contract. Said policy shall name EKPC as an Additional Insured to the extent necessary to fulfill Consultant's indemnity obligations under this agreement, with said policy designated to be primary. Said policy shall include an endorsement providing that the underwriter(s) have waived their Rights of Recovery Against Others (subrogation) against EKPC and EKPC's insurance carrier(s).

d) **Aircraft Public Liability Insurance**: If applicable, Consultant shall provide prior to the start of Work, evidence of Consultant's Aircraft Public Liability Insurance covering fixed wing and rotorcraft aircraft whether owned, non-owned, leased, hired or assigned with a combined single minimum limit for bodily injury an property damage of Five Million Dollars ($5,000,000) including passenger liability coverage. Said policy shall include an endorsement providing that the underwriter(s) have waived their rights of subrogation against EKPC and EKPC's insurance carrier(s).

e) **Marine Liability Insurance**: If applicable, Consultant shall provide prior to the start of Work, evidence of Consultant's Marine Liability Insurance, including if appropriate Wharfinger's Liability, covering the operation of waterborne vessels whether owned, non-owned, leased, hired or assigned with a combined single minimum limit for bodily injury an property damage of Five Million Dollars ($5,000,000) including passenger liability coverage. Said policy shall include an endorsement providing that the underwriter(s) have waived their rights of subrogation against EKPC and EKPC's insurance carrier(s). Said policy shall name EKPC as an Additional Insured to the extent necessary to fulfill Consultant's indemnity obligations under this agreement, with Consultant's policy deemed to be primary.

f) **Environmental Impairment ("Pollution") Liability Insurance**: If applicable, consultant shall provide prior to the start of work, evidence of Consultant's Environmental Impairment Liability Insurance covering Contracting operations. Said policy shall extend to Consultant's use of vehicles as well as Consultant's operations and work, and shall provide for monitoring, testing, cleanup and remediation expenses. Limits of liability shall not be less than $1,000,000 Each Occurrence. Said policy shall be endorsed to provide Additional Insured status of EKPC and shall be endorsed to provide Waiver of Subrogation in favor of EKPC.

g) **Umbrella/Excess Liability Insurance**: Consultant shall provide prior to start of work evidence of Consultant's Umbrella or Excess Liability Insurance providing excess limits of liability over and above the primary policies outlined in Items (A) Employers Liability, (B) Commercial General Liability, and (C) Commercial Automobile Liability above, and if applicable Item (F) Environmental Impairment ("Pollution") Liability Insurance. Said policy shall provide in the minimum Five Million Dollars ($2,000,000) Each Occurrence and, Five Million Dollars ($2,000,000) in the Aggregate. Said policy shall be "follow-form" to the extent of coverage provisions in the primary forms (A) (B) (C) and (E) with regards to coverage terms and policy provisions. Said coverage must continue in force for a minimum of two (2) years from the Acceptance of Work by EKPC.

h) **Professional/Errors and Omissions Liability Insurance**: If applicable, Consultant shall provide prior to the start of work, evidence of Consultant's Professional Liability Insurance insuring Consultant and any other firms or persons under Consultant's direction, professional acts, errors, omissions in planning, operation, design, and completion of the contracted work. Said insurance will have as minimum limits of liability $500,000 Each Occurrence and $1,000,000 Aggregate. Should policy contain a deductible clause, said deductible shall be shown on the Certificate of Insurance, and Consultant's carrier shall agree to pay any such claims "first dollar" and then recover the deductible amount from Consultant.

Quality of Insurance Coverage

The above policies to be provided by Consultant shall be written by companies satisfactory to EKPC or having a Best Rating of not less than A- ("Excellent"). These policies shall not be materially changed or cancelled except with thirty (30) days written notice to EKPC from the Consultant and the Insurance Carrier. Evidence of coverage, notification of cancellation or other changes shall be mailed to:

ATTN: Manager, Business Insurance
East Kentucky Power Cooperative, Inc.

P. O. Box 707
Winchester, KY 40392-0707

Implication of Insurance

EKPC shall not be obligated to review any of Consultant's Certificates of Insurance, insurance policies, or endorsements, or to advise Consultant of any deficiencies in such documents. Minimum limits and coverages required under this Article should not be construed to necessarily be adequate for Consultant's own insurance and risk management needs. Any receipts of such documents or their review by EKPC shall not relieve Consultant from or be deemed a waiver of EKPC's rights to insist on strict fulfillment of Consultant's obligations under the Contract.

Certificates of Insurance

EKPC reserves the right to request and receive a summary of coverage of any of the above policies or endorsements.

Other Notices

Consultant shall provide notice of any accidents or claims at the Work site to EKPC's Manager, Business Insurance at the above address, and EKPC's site authorized representative.

Rebecca Witt

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Tuesday, December 22, 2009 10:32 AM
To: Bobby Sexton (E-mail); Dan Brewer; Paul Embs (E-mail); Ted Hampton (E-mail); Bill Prather; cperry@fme.coop; carol.fraley@graysonrecc.com; Jim Jacobus; Don Schaefer; Kerry Howard (E-mail); Mickey Miller; Mark Stallons; larryh@srelectric.com; debbiem; Allen Anderson; Barry Myers (E-mail)
Cc: jimadkins25@aol.com; Tony Campbell; Jim Lamb; Brenda Eames; Howard Nguyen
Subject: RFP Responses - Rate Design Feasibility Study

Importance: High

Ladies and Gentlemen:

EKPC has received 6 response proposals to the Rate Design Feasibility Study RFP issued on November 16, 2009. Electronic copies of those proposals are being forwarded to you on a CD ROM via regular mail. The CDs should go into the mail today (December 22, 2009). The files on the CD are grouped by respondent as follows:

Burns & McDonnell (B&M)	Black & Veatch (B&V)	C. H. Guernsey (GUER)
Power Supply Engineering (PSE)	Prime Group (Prime)	Shaw Group (Shaw)

While I am sure you are aware of the sensitive nature of any bid proposal, I thought it best to review a few things. EKPC has utilized its Supply Chain Management procedure to process this RFP. The responses from the various vendors are ***Confidential***. They should not be widely distributed within your organization; distribution should be limited to the smallest number of individuals possible. EKPC has retained Jim Adkins to assist us with this project, and he will be provided copies of the bid proposals, so you do not need to pass along the proposals to him. If during your review of the proposals questions arise, please ***do not*** contact the vendor – send those questions to me and they will be forwarded to the vendors using the Supply Chain Management procedures. In the unlikely event a vendor contacts you, please ***do not*** discuss the proposals with the vendor, but direct him/her to contact Brenda Eames, EKPC Senior Sourcing Agent at 859-745-9766 or brenda.eames@ekpc.coop. This will ensure that all suppliers are being provided the same information towards a fair and ethical process.

We have developed a checklist on an Excel spreadsheet that will be used internally to organize the evaluation of the proposals. That spreadsheet is included on the CD, and you are welcome to use it if it will help in your review of the proposals. If you have any questions, please contact me.

EKPC welcomes your comments and observations on these proposals, which in order to stay on the timeline included in the RFP are needed from you by the close of business on **January 6, 2010**. We just stress that you recognize the sensitive and confidential nature of the proposals and encourage you to take all necessary precautions to maintain the confidential nature of the information provided by the vendors. Thank you.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Tuesday, January 12, 2010 1:20 PM
To: Bobby Sexton (E-mail); Dan Brewer; Paul Embs (E-mail); Ted Hampton (E-mail); Bill Prather; cperry@fme.coop; carol.fraley@graysonrecc.com; Jim Jacobus; Don Schaefer; Kerry Howard (E-mail); Mickey Miller; Mark Stallons; larryh@srelectric.com; debbiem; Allen Anderson; Barry Myers (E-mail)
Cc: jimadkins25@aol.com; Tony Campbell; Jim Lamb; Brenda Eames; Ann Wood
Subject: Rate Design Feasibility Study

Ladies and Gentlemen:

The time for reviewing and evaluating the response proposals to the Rate Design Feasibility Study RFP is nearly completed. While no final decision has been made as to the successful bidder, EKPC's internal analysis has narrowed the possibilities down to two proposals. Those proposals are the ones submitted by ***C. H. Guernsey*** and ***Power Supply Engineering***. EKPC seeks and welcomes any comments or observations you may have on these two proposals. However, in order to stay on the timeline included in the RFP, any comments or observations need to be submitted by the close of business tomorrow, **January 13, 2010**.

Please remember that the proposals are ***Confidential*** and the proposals should not be widely distributed within your organization. Thank you.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
359.745.9243
isaac.scott@ekpc.coop

Rebecca Witt

From:	Isaac Scott [isaac.scott@ekpc.coop]
Sent:	Friday, January 22, 2010 4:12 PM
To:	Bobby Sexton (E-mail); Dan Brewer; Paul Embs (E-mail); Ted Hampton (E-mail); Bill Prather; cperry@fme.coop; carol.fraley@graysonrecc.com; Jim Jacobus; Don Schaefer; Kerry Howard (E-mail); Mickey Miller; Mark Stallons; larryh@srelectric.com; debbiem; Allen Anderson; Barry Myers (E-mail)
Cc:	jimadkins25@aol.com; Tony Campbell; Jim Lamb; Brenda Eames; Ann Wood
Subject:	Rate Design Feasibility Study - Vendor Selected

Ladies and Gentlemen,

I just wanted to pass along the news that EKPC is finalizing the paperwork with ***Power System Engineering, Inc.*** to perform the Rate Design Feasibility Study. I'm sure we will be in touch in the near future to set up meetings and arrange correspondence to get the Study going. Thank you for your comments and input in the selection process.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

√ **Rebecca Witt**

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Wednesday, February 03, 2010 8:18 AM
To: Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; Dan Brewer; Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); bprather@farmersrecc.com; Wayne Davis; Jerry Carter; cperry@fme.coop; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; rodneychrisman@jacksonenergy.com; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; Nicky Rapier; J. Edward Boone (E-mail); randyb@srelectric.com; debbiem; gay; denise@shelbyenergy.com; Allen Anderson; Stephen Johnson; Ruby Patterson; Barry Myers (E-mail); John Patterson; abeard@tcrecc.com
Cc: Tony Campbell; Jim Lamb; Stacy Barker; John Twitchell; David Smart; Craig Johnson; Denver York; jimadkins25@aol.com
Subject: Kick-Off Meeting with Power System Engineering

Importance: High

Ladies and Gentlemen:

EKPC has selected Power System Engineering, Inc. of Minneapolis, MN to conduct the Rate Design Feasibility Study. We have had preliminary discussions with Power System and they are eager to get started on the project.

Power System representatives will be at EKPC's headquarters on February 9th and 10th to hold kick-off meetings. After the Board Meeting is adjourned on February 9th, Power System will be meeting with EKPC staff. Anyone already here for the Board Meeting is welcome to stay and be part of that meeting. On **February 10th** we will have a kick-off meeting between Power System and the Member Cooperatives. The meeting will be held in the East Veech/Employee Lounge area. The meeting will start at **9:00 a.m.** and should be finished by **2:00 p.m.** Lunch will be provided.

The February 10th meeting will be a chance for Power System and the Member Cooperatives to meet and have an opportunity to share interests and concerns relating to rate design. There will probably be some discussion of the work plan and Power System's plans on moving forward.

So we can properly plan for lunch, please let me know by the end of the day on Monday, February 8th how many will be attending the meeting on February 10th from your Cooperative.

Power System stressed in its bid proposal that it wanted to work with all of the Member Cooperatives and they plan on visiting each Member Cooperative to get a good understanding of your rate design needs and issues. They would also like to have a point of contact at each Member Cooperative. Please give consideration between now and next Wednesday of who at your Cooperative you would like to designate as the point of contact. You might want to give consideration also to naming a back-up or alternate person as well. We would like to get the names of your point of contact person when we meet next Wednesday.

EKPC is also planning on holding a conference call with the Member Cooperatives tomorrow afternoon (February 4th) to talk about the Rate Design Feasibility Study and the role of Power System. Details on this call will be sent later.

If you have any questions, please feel free to contact me. Thank you.

Isaac S. Scott
Manager - Pricing

East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Wednesday, February 03, 2010 12:10 PM
To: Rebecca Witt
Cc: Mark Stallons; Mike Cobb
Subject: RE: Kick-Off Meeting with Power System Engineering

Thank you for the response.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

-----Original Message-----
From: Rebecca Witt [mailto:rwitt@owenelectric.com]
Sent: Wednesday, February 03, 2010 10:57 AM
To: Isaac Scott
Cc: Mark Stallons; Mike Cobb
Subject: RE: Kick-Off Meeting with Power System Engineering

Isaac,

Mark Stallons, Mike Cobb and Becky Witt will be attending for Owen.

Thanks,
Becky

From: Isaac Scott [mailto:isaac.scott@ekpc.coop]
Sent: Wednesday, February 03, 2010 8:18 AM
To: Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; Dan Brewer; Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); bprather@farmersrecc.com; Wayne Davis; Jerry Carter; cperry@fme.coop; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; rodneychrisman@jacksonenergy.com; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; Nicky Rapier; J. Edward Boone (E-mail); randyb@srelectric.com; debbiem; gay; denise@shelbyenergy.com; Allen Anderson; Stephen Johnson; Ruby Patterson; Barry Myers (E-mail); John Patterson; abeard@tcrecc.com
Cc: Tony Campbell; Jim Lamb; Stacy Barker; John Twitchell; David Smart; Craig Johnson; Denver York; jimadkins25@aol.com
Subject: Kick-Off Meeting with Power System Engineering
Importance: High

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So we can properly plan for lunch, please let me know by the end of the day on Monday, February 8th how many will be attending the meeting on February 10th from your Cooperative.

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East Kentucky Power Cooperative, Inc.
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P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Thursday, February 04, 2010 8:16 AM
To: Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; Dan Brewer; Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); bprather@farmersrecc.com; Wayne Davis; Jerry Carter; cperry@fme.coop; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; rodneychrisman@jacksonenergy.com; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; Nicky Rapier; J. Edward Boone (E-mail); randyb@srelectric.com; debbiem; gay; denise@shelbyenergy.com; Allen Anderson; Stephen Johnson; Ruby Patterson; Barry Myers (E-mail); John Patterson; abeard@tcrecc.com; Carol Wright
Cc: Tony Campbell; Jim Lamb; Stacy Barker; John Twitchell; Craig Johnson; Denver York; jimadkins25@aol.com; forward to davismart at FTB; Wanda Kirby
Subject: Conference Call - Kick-Off Meeting with Power System Engineering

Ladies and Gentlemen:

As I noted in Wednesday's e-mail, EKPC wants to have a conference call this afternoon to talk about the Rate Design Feasibility Study and Power System Engineering. We now have the details for that call.

Date:	February 4, 2010
Time:	3:00 p.m. EST
Phone Number:	1-877-597-2663
Conference ID Number:	5880520

We don't expect this to be a long call, but important in keeping everyone informed about this Study. We are looking forward to talking with you this afternoon.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

Rebecca Witt

From:	Isaac Scott [isaac.scott@ekpc.coop]
Sent:	Monday, February 08, 2010 2:57 PM
To:	Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; Dan Brewer; Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); bprather@farmersrecc.com; Wayne Davis; Jerry Carter; cperry@fme.coop; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; rodneychrisman@jacksonenergy.com; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; Nicky Rapier; J. Edward Boone (E-mail); randyb@srelectric.com; debbiem; gay; denise@shelbyenergy.com; Allen Anderson; Stephen Johnson; Ruby Patterson; Barry Myers (E-mail); John Patterson; abeard@tcrecc.com; Mark Keene; Carol Wright
Cc:	Tony Campbell; Jim Lamb; Stacy Barker; John Twitchell; Craig Johnson; Denver York; jimadkins25@aol.com; forward to davismart at FTB
Subject:	RE: Kick-Off Meeting with Power System Engineering
Importance:	High

Ladies and Gentlemen:

By now, I'm sure you all have seen the weather forecast for tomorrow for the state. I have been in contact with Power System, and the consultants are en route. We do not know when they will be arriving here Tuesday, so that session may or may not happen. At this time, we are still planning on holding the session on Wednesday here at headquarters. Depending on conditions, we may start a little later than 9:00 a.m. and adjust off of the lunch hour.

I know these situations play havoc with your schedules, and I appreciate your patience. In the event we have to cancel, I will make sure you get an e-mail message and phone call. Thank you.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
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Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

√ **Rebecca Witt**

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Tuesday, February 09, 2010 10:50 AM
To: Isaac Scott; Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; Dan Brewer; Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); bprather@farmersrecc.com; Wayne Davis; Jerry Carter; cperry@fme.coop; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; rodneychrisman@jacksonenergy.com; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; Nicky Rapier; J. Edward Boone (E-mail); randyb@srelectric.com; debbiem; gay; denise@shelbyenergy.com; Allen Anderson; Stephen Johnson; Ruby Patterson; Barry Myers (E-mail); John Patterson; abeard@tcrecc.com; Mark Keene; Carol Wright
Cc: Tony Campbell; Jim Lamb; Stacy Barker; John Twitchell; Craig Johnson; Denver York; jimadkins25@aol.com; forward to davismart at FTB
Subject: Kick-Off Meeting - CANCELLED

Importance: High

Ladies and Gentlemen:

Given the weather forecast for tonight and tomorrow, it is not reasonable to try and go ahead with the Kick-Off Meeting we were planning with Power System tomorrow at EKPC headquarters. So our meeting scheduled for Wednesday, February 10th is **cancelled**. We will try and reschedule at a later date or make some other arrangements for a kick-off with the Members. I realize several of you were juggling schedules to make this work, and I appreciate that effort. I will let you know when we have other arrangements made. Thank you.

Isaac S. Scott
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East Kentucky Power Cooperative, Inc.
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Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

Rebecca Witt

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Wednesday, February 10, 2010 1:46 PM
To: Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; Dan Brewer (E-mail); Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); bprather@farmersrecc.com; Wayne Davis; Jerry Carter; cperry@fme.coop; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; Carol Wright; Mark Keene; rodneychrisman@jacksonenergy.com; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Cheryl Thomas; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; Nicky Rapier; J. Edward Boone (E-mail); randyb@srelectric.com; debbiem; gay; denise@shelbyenergy.com; Allen Anderson; Stephen Johnson; Ruby Patterson; Amy Acton; Barry Myers (E-mail); John Patterson; abeard@tcrecc.com
Cc: jimadkins25@aol.com; Jim Lamb; Macke, Rich; Dennis Eicher
Subject: Rate Design Feasibility Study - Member Cooperatives

Ladies and Gentlemen,

EKPC staff met with Dennis Eicher and Rich Macke of Power System Engineering (PSE) yesterday (February 9th) and discussed getting started on the Rate Study. PSE has been gathering publicly available information to get an understanding of EKPC and the Member Cooperatives. EKPC received its first request for information for the wholesale cost-of-service study from PSE on February 3rd and we plan on finishing responses by the end of today.

PSE is working to keep this project on schedule and is ready to start gathering information from each of you. Rich Macke will be in contact with each of you within the next day or so and among the items he will be covering:

- Identifying the person or persons at the Member Cooperative who will be the point of contact for PSE.

- Getting out the first request for information that will be part of the cost-of-service study PSE will perform for each Member Cooperative. Rich will be describing how your responses will be transmitted to PSE.

- Scheduling meetings between each Member Cooperative and the PSE team. PSE wants to meet with each of you to gain an understanding of your particular situation and your concerns and issues as it relates to rate design. PSE will be scheduling these meetings with you, and would like to complete these meetings by March 12, 2010. PSE personnel involved with these on-site meetings will be Rich Macke, Jeff Laslie, and Brian Burandt.

We also want to announce we have rescheduled the group meeting with PSE originally scheduled for today. That meeting will be held on March 12, 2010, beginning at 10:00 a.m. at EKPC's headquarters. We will get more details out in the coming weeks, but we wanted to get this out to you as soon as possible so you could get it on your calendars.

While PSE wants to stay on schedule with this project, they have also acknowledged that they realize the Member Cooperatives have their usual work to do as well. We appreciate your willingness to participate in this project and provide information to PSE as promptly as possible. If you have any questions, please feel free to contact either Jim Adkins or myself. Thank you for patience and we look forward to seeing you all here on March 12th.

Isaac S. Scott

Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

Rebecca Witt

From: Laslie, Jeffrey [lasliej@powersystem.org]
Sent: Wednesday, February 10, 2010 4:14 PM
To: Mark Stallons
Cc: macker@powersystem.org
Subject: FW: Rate and Cost of Service Study Data Request
Attachments: RS-6.xlsx; RS-5.xlsx; RS-4.xlsx; RS-3.xlsx; RS-1.xlsx; JCL-Stallons-2-10-10.pdf

Dear Mr. Stallons:

I have attached a letter with attachments outlining the initial list of data needed to complete the Rate and Cost of Service Study. Please advise if you have any questions or concerns.

Thank you,

Jeff Laslie
Power System Engineering, Inc.
Phone: 317-322-5906
Fax: 317-322-5924
Cell: 317-696-0820
lasliej@powersystem.org

Power System
Engineering, Inc.

Via e-mail

February 10, 2010

Mr. Mark Stallons
President and CEO
Owen Electric Cooperative
P.O. Box 400
Owenton, KY 40359-0400

Subject: Rate and Cost of Service Study Data Request

Dear Mr. Stallons:

We are enclosing a list of data needed for the Rate and Cost of Service Study we will be conducting for Owen Electric Cooperative (Owen). Also enclosed are various data request forms. Please note that Item No. 1 is one of the most critical aspects of the data request. In order to develop the revenue requirements, prepare the cost of service study and evaluate potential rate design changes, it is essential that we have complete and accurate data regarding the number of consumers, energy sales, billing demand and revenue under the present rates. It is important that this information be broken down by rate schedule or code.

Please forward all readily available requested data at your earliest convenience. In terms of providing the remaining items, please follow the priority ranking. Often the data items with a low priority are not needed for at least two weeks after the high priority items have been submitted.

We will follow-up with a phone call next week to see how things are coming along and answer any questions you might have. In the meantime, if you should have any questions regarding the data request, please do not hesitate to call me at (317) 322-5906 or Rich Macke at (763) 755-5122. We look forward to working with you on this project.

Very truly yours,

Jeffrey C. Laslie
Senior Financial Analyst

KY0591018/mmc
cc: Rich Macke, Power System Engineering, Inc.
Enclosure

6919 E. 10th Street, Suite E-1A, Indianapolis, IN 46219
Tel: 317.322.5906 • Fax: 317.322.5924 • Web Site: www.powersystem.org
Madison, WI . Minneapolis, MN . Marietta, OH . Indianapolis, IN . Sioux Falls, SD

OWEN ELECTRIC COOPERATIVE
RATE AND COST OF SERVICE STUDY
DATA REQUEST

TEST YEAR: Actual 2009

Item	Data Request	Priority	Data Form Request	Due Date
1	Breakdown of sales for each month of 2009 by <u>**rate class**</u> (not consumer classifications shown on RUS Form 7) showing the following: a. Number of consumers served. b. Energy sales (kWh). c. Total monthly billing demand (kW) for large power type class and/or other demand or load factor type rate classes. d. Revenue. Breakdown between the revenue developed from the rate schedule itself, the Fuel Adjustment Clause (FAC) and the Environmental Surcharge Rider. Please use the provided Excel file **RS-1.** **Note: We generally find that analyzing this data and calculating revenue under existing rates can be one of the most time consuming and costly parts of the study. The accuracy and completeness of the data that is provided in response to this request is an important determinant in the cost, accuracy and overall quality of our analysis.**	High	RS-1	2/16/10
2	Billing demand and energy usage by customer for each month of 2009 for each customer served under a large power type rate and any other rate incorporating a demand charge. Please provide this data in Excel format or a format importable into Excel such as delimited text or fixed with text. The preferred layout is a simple list or "dump" of billing records with all relevant fields for the test year including each demand rate code. If this is not possible, please use the provided Excel file **RS-3**.	High	RS-3	2/16/10
3	Copy of Cooperative's current retail rate schedules. Also, provide the monthly FAC by month from January 2009 to present.	High		2/16/10

OWEN ELECTRIC COOPERATIVE
RATE STUDY
DATA REQUEST
(Continued)

Item	Data Request	Priority	Data Form Request	Due Date
4	Monthly RUS Form 7s or equivalent for each month of 2009 and any available for 2010.	Medium		2/23/10
5	Annual RUS Form 7s or equivalent (all pages) for 2004 through 2009.	Medium		2/23/10
6	Information on lighting classes (please use Excel file **RS-4**) including: a. Number of lights by size and type. Breakdown between metered and unmetered if appropriate. b. Estimated monthly usage recorded for each size of unmetered lights. c. Operation and maintenance expense recorded for 2009 for 1) street lights and 2) security lights. What account number was used to record this expense? d. Estimated plant in service for 1) street lights and 2) security lights for December 31, 2009. What account numbers were used to record this investment?	Medium	RS-4	2/23/10
7	Operating Budget for 2010. Note that it would be helpful if the budgeted kWh sales were broken down by rate class or, in the alternative, consumer classes shown on Form 7, although that is not necessary.	Medium		2/23/10
8	List of all loans from RUS, CFC and others. This can be provided by copying the latest RUS and/or CFC Statement of Loans.	Low		3/2/10
9	Copy of the Cooperative's most current RUS or CFC financial forecast, if any, in Excel format.	Low		3/2/10
10	Copy of the capital credits policy of the Cooperative showing: a. Policy regarding general retirements including targeted cycle. b. Policy regarding payment to estates. c. Methodology used to assign capital credits at the end of the year to the accounts of individual customers. If the total amount is prorated to each customer on the basis of sales (revenue), is an adjustment made to take purchased power out prior to the allocation?	Low		3/2/10

OWEN ELECTRIC COOPERATIVE
RATE STUDY
DATA REQUEST
(Continued)

Item	Data Request	Priority	Data Form Request	Due Date
11	Plant and Accumulated Reserves for Depreciation account balances in accordance with the Uniform System of Accounts for December 31, 2009 (i.e., plant investments in Accts. 361, 364, 365, etc.). The attached file **RS-5** has been included to assist in providing this information.	Low	RS-5	3/2/10
12	Statement of income and expense accounts in accordance with the Uniform System of Accounts for the period January 1 to December 31, 2009 (i.e., expense in Accts. 580, 583, 920, etc.). The attached file **RS-5** has been included to assist in providing this information.	Low	RS-5	3/2/10
13	Data on any major adjustments in revenue or kWh sales due to meter reading errors, etc., made during the last year.	Low		3/2/10
14	List of the total number of service transformers installed on the system summarized by kVA capacity. Please use attached Excel file **RS-6** or equivalent. If this data is not readily available, please let us know.	Low	RS-6	3/2/10
15	Tabulation of miles of VØ and 3Ø primary line broken down by conductor size and type. This can usually be obtained relatively easily from the model of your distribution system maintained by your engineer. Please use the attached Excel File **RS-6** or equivalent.	Low	RS-6	3/2/10
16	Please answer the following concerning the Cooperative's metering capabilities: a. Does the Cooperative have Automatic Meter Reading (AMR) or Advanced Metering Infrastructure (AMI)? If yes, please briefly describe.	Low		3/2/10
17	Please provide any equity management plan/policy goal in place at the Cooperative, such as TIER, equity ratio, etc.	Low		3/2/10

OWEN ELECTRIC COOPERATIVE
RATE STUDY
DATA REQUEST
(Continued)

Item	Data Request	Priority	Data Form Request	Due Date
18	For each customer served on a contract rate, please provide the following: a. Rate schedule including any unique facility charge. b. Copy of the Electric Service Agreement. c. Identification of facilities used to provide service: 1. Dedicated facilities' description and original cost and book cost (net). 2. Other facilities (shared) description and original cost and book cost (net). 3. Please illustrate location of accounts(s) and facilities on system map(s). d. Identification of any cost of service or rate analysis completed for the customer including analysis used to determine patronage capital allocation or margin analysis.	Low		3/2/10
19	Please provide the Case Number from the Cooperative's most recent rate case filing.	Low		3/2/10

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Jan 2009

Rate Code	Applicable Rate Schedule	No. of Consumers		Energy (kWh) Sales			Demand (kW) Sales		Revenues			
		Single Phase	Three Phase	Metered[1]	Billed[2]	Submetered	Metered	Billed[3]	Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)

TOTAL

Notes
1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Feb 2009

Rate Code	Applicable Rate Schedule	No. of Consumers		Energy (kWh) Sales			Demand (kW) Sales		Revenues			
		Single Phase	Three Phase	Metered[1] (kWh)	Billed[2] (kWh)	Submetered (kWh)	Metered (kW)	Billed[3] (kW)	Base Rate[4] ($)	FCA ($)	Environmental Surcharge ($)	Total ($)
TOTAL												

Notes
1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period.
2 For use if kWh billed is different from kWh metered due to kWh minimums.
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor.
4 Outdoor Lighting revenues should be shown as separate rate class.

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Mar 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1]	Energy (kWh) Sales: Billed[2]	Energy (kWh) Sales: Submetered	Demand (kW) Sales: Metered	Demand (kW) Sales: Billed[3]	Revenues: Base Rate[4]	Revenues: FCA	Revenues: Environmental Surcharge	Revenues: Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
TOTAL												

Notes
1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Apr 2009

Rate Code	Applicable Rate Schedule	No. of Consumers		Energy (kWh) Sales			Demand (kW) Sales		Revenues			
		Single Phase	Three Phase	Metered[1]	Billed[2]	Submetered	Metered	Billed[3]	Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)

TOTAL

Notes
1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period.
2 For use if kWh billed is different from kWh metered due to kWh minimums.
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor.
4 Outdoor Lighting revenues should be shown as separate rate class.

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for May 2009

Rate Code	Applicable Rate Schedule	No. of Consumers		Energy (kWh) Sales			Demand (kW) Sales		Revenues			
		Single Phase	Three Phase	Metered[1]	Billed[2]	Submetered	Metered	Billed[3]	Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
TOTAL												

Notes

1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period.
2 For use if kWh billed is different from kWh metered due to kWh minimums.
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor.
4 Outdoor Lighting revenues should be shown as separate rate class.

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Jun 2009

Rate Code	Applicable Rate Schedule	No. of Consumers		Energy (kWh) Sales			Demand (kW) Sales		Revenues			
		Single Phase	Three Phase	Metered[1]	Billed[2]	Submetered	Metered	Billed[3]	Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
TOTAL												

Notes
1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period.
2 For use if kWh billed is different from kWh metered due to kWh minimums.
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor.
4 Outdoor Lighting revenues should be shown as separate rate class.

Rate Code	Applicable Rate Schedule	No. of Consumers		Energy (kWh) Sales			Demand (kW) Sales		Revenues			
		Single Phase	Three Phase	Metered[1]	Billed[2]	Submetered	Metered	Billed[3]	Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
TOTAL												

Notes
1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period.
2 For use if kWh billed is different from kWh metered due to kWh minimums.
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor.
4 Outdoor Lighting revenues should be shown as separate rate class.

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Aug 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1] (kWh)	Energy (kWh) Sales: Billed[2] (kWh)	Energy (kWh) Sales: Submetered (kWh)	Demand (kW) Sales: Metered (kW)	Demand (kW) Sales: Billed[3] (kW)	Revenues: Base Rate[4] ($)	Revenues: FCA ($)	Revenues: Environmental Surcharge ($)	Total ($)
TOTAL												

Notes
1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums.
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor.
4 Outdoor Lighting revenues should be shown as separate rate class.

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Sep 2009

Rate Code	Applicable Rate Schedule	No. of Consumers		Energy (kWh) Sales			Demand (kW) Sales		Revenues			
		Single Phase	Three Phase	Metered[1]	Billed[2]	Submetered	Metered	Billed[3]	Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)

TOTAL

Notes

1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period.
2 For use if kWh billed is different from kWh metered due to kWh minimums.
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor.
4 Outdoor Lighting revenues should be shown as separate rate class.

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Oct 2009

Rate Code	Applicable Rate Schedule	No. of Consumers		Energy (kWh) Sales			Demand (kW) Sales		Revenues			
		Single Phase	Three Phase	Metered[1]	Billed[2]	Submetered	Metered	Billed[3]	Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
TOTAL		0		0		0	0	0	0	0		0

Notes
1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor.
4 Outdoor Lighting revenues should be shown as separate rate class.

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Nov 2009

Rate Code	Applicable Rate Schedule	No. of Consumers		Energy (kWh) Sales			Demand (kW) Sales		Revenues			
		Single Phase	Three Phase	Metered[1]	Billed[2]	Submetered	Metered	Billed[3]	Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)

TOTAL

Notes

1 *For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period.*
2 For use if kWh billed is different from kWh metered due to kWh minimums.
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor.
4 Outdoor Lighting revenues should be shown as separate rate class.

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Dec 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1]	Energy (kWh) Sales: Billed[2]	Energy (kWh) Sales: Submetered	Demand (kW) Sales: Metered	Demand (kW) Sales: Billed[3]	Revenues: Base Rate[4]	Revenues: FCA	Revenues: Environmental Surcharge	Revenues: Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
TOTAL												

Notes
1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period.
2 For use if kWh billed is different from kWh metered due to kWh minimums.
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor.
4 Outdoor Lighting revenues should be shown as separate rate class.

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Total 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	Three Phase	Energy (kWh) Sales Metered[1]	Billed[2]	Submetered	Demand (kW) Sales Metered	Billed[3]	Revenues Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
		#DIV/0!	#DIV/0!									
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TOTAL												

Notes

1. For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2. For use if kWh billed is different from kWh metered due to kWh minimums.
3. kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4. Outdoor Lighting revenues should be shown as separate rate class.

4 Outdoor Lighting revenues should be shown as separate rate class.

Total

PSE Form RS-3

Big Sandy RECC
Large Power Rate (LPR)

(1) Customer	(2) Units	(3) Jan	(4) Feb	(5) Mar	(6) Apr	(7) May	(8) Jun	(9) Jul	(10) Aug	(11) Sep	(12) Oct	(13) Nov	(14) Dec	(15) Total
Customer Name and Acct. No.														
Demand	kW													
Energy	kWh													
Service Charge	$													
Total Billing	$													
Customer Name and Acct. No.														
Demand	kW													
Energy	kWh													
Service Charge	$													
Total Billing	$													
Customer Name and Acct. No.														
Demand	kW													
Energy	kWh													
Service Charge	$													
Total Billing	$													
Customer Name and Acct. No.														
Demand	kW													
Energy	kWh													
Service Charge	$													
Total Billing	$													
Customer Name and Acct. No.														
Demand	kW													
Energy	kWh													
Service Charge	$													
Total Billing	$													

Customize if necessary to accommodate all rate components

Item No 16
Page 76 of 449

Note: Billed Demand should include any adjustments for power factor penalties.

PSE Form RS-3

Big Sandy RECC
Large Power Rate (LPR)

(1) Customer	(2) Units	(3) Jan	(4) Feb	(5) Mar	(6) Apr	(7) May	(8) Jun	(9) Jul	(10) Aug	(11) Sep	(12) Oct	(13) Nov	(14) Dec	(15) Total
Customer Name and Acct. No.														
Demand	kW													
Energy	kWh													
Service Charge	$													

Note: Billed Demand should include any adjustments for power factor penalties.

PSE Form RS-4

Big Sandy RECC
Outdoor Lighting

(1)	(2)	(3)
	No. of Lights	Estimated Monthly Usage (kWh)
Yard Lights (F-10)		
100 W MH	-	-
250 W MH	-	-
400 W (Reg)	-	-
400 W (Flood)	-	-
250 W MH	-	-
500 Watt	-	-
1,500 Watt	-	-
250 W HPS	-	-
Total	-	-

Account Number (i.e. acct. 371)	Total
Plant Investment (12/31/09)	-
O&M Expense (1/1/09 to 12/31/09)	-

PSE Form RS-5

Big Sandy RECC
Plant and Accumlated Reserves for Depreciation Account Data
Balances as of December 31, 2009

Acct. No.	Description	Plant	Accumulated Depreciation	Comments
Intangible Plant				
301	Organization			
302	Franchises and consents			
303	Miscellaneous intangible plant			
	Subtotal	0	0	
Steam Production				
310	Land and land rights			
311	Structures and improvements			
312	Boiler plant equipment			
313	Engines and engine driven generators			
314	Turbogenerator units			
315	Accessory electric equipment			
316	Miscellaneous power plant equipment			
	Subtotal	0	0	
Transmission				
350	Land and land rights			
352	Structures and improvements			
353	Station equipment			
354	Tower and fixtures			
355	Poles and fixtures			
356	Overhead conductor & devices			
357	Underground conduit			
358	Underground conductors & devices			
359	Roads and trails			
	Subtotal	0	0	
Distribution				
360	Land and land rights			
361	Structures and improvements			
362	Station equipment			
363	Storage battery equipment			
364	Poles, towers, and fixtures			
365	Overhead conductor & devices			
366	Underground conduits			
367	Underground conductors & devices			
368	Line transformers			
369	Services			
370	Meters			
371	Installation on customer's premises			
372	Leased property-customer's premises			
373	Street lighting and signal systems			
	Subtotal	0	0	

PSE Form RS-5

Big Sandy RECC
Plant and Accumlated Reserves for Depreciation Account Data
Balances as of December 31, 2009

Acct. No.	Description	Plant	Accumulated Depreciation	Comments
General				
389	Land and land rights			
390	Structures and improvements			
391	Office furniture and equipment			
392	Transportation equipment			
393	Stores equipment			
394	Tools, shop and garage equipment			
395	Laboratory equipment			
396	Power operated equipment			
397	Communications equipment			
398	Miscellaneous equipment			
399	Other tangible equipment			
	Subtotal	0	0	

Please provide a description of what is included in the following accounts:

371 Installation on customer's premises ______________________

372 Leased property on customer's premises ______________________

PSE Form RS-5

Big Sandy RECC
Expense Account Data
January 01, 2009 Thru December 31, 2009

Acct. No.	Description	Total	Comments
Steam Power Generation Operations			
500	Operations supervision and engineering		
501	Fuel		
502	Steam expenses		
503	Steam from other sources		
504	Steam transferred - credit		
505	Electric expenses		
506	Misc steam power expenses		
507	Rents		
509	Allowances		
	Subtotal	0	
Steam Power Generation Maintenance			
510	Maintenance supervision and engineering		
511	Maintenance of structures		
512	Maintenance of boiler plant		
513	Maintenance of electric plant		
514	Maintenance of misc. steam plant		
	Subtotal	0	
Other Power Supply Expenses			
555	Purchased power		
Transmission Operations			
560	Supervision and engineering		
561	Load dispatching		
562	Station expenses		
563	Overhead line		
564	Underground line		
565	Transmission of electricity by others		
566	Miscellaneous		
567	Rents		
	Subtotal	0	
Transmission Maintenance			
568	Supervision and engineering		
569	Maintenance of structures		
570	Maintenance of station equipment		
571	Maintenance of overhead line		
572	Maintenance of underground line		
573	Miscellaneous		
	Subtotal	0	

PSE Form RS-5

Big Sandy RECC
Expense Account Data
January 01, 2009 Thru December 31, 2009

Acct. No.	Description	Total	Comments
Distribution Operations			
580	Supervision and engineering		
581	Load dispatching		
582	Station		
583	Overhead line		
584	Underground line		
585	Street lighting and signal systems		
586	Meter		
587	Customer installation		
588	Miscellaneous		
589	Rents		
	Subtotal	0	
Distribution Maintenance			
590	Supervision and engineering		
591	Maintenance of structure		
592	Maintenance of station equipment		
593	Maintenance of overhead line		
594	Maintenance of underground line		
595	Maintenance of line transformer		
596	Maintenance of street lighting		
597	Maintenance of meters		
598	Miscellaneous maintenance		
	Subtotal	0	
Customer Accounting			
901	Supervision		
902	Meter reading		
903	Customer records and collection		
904	Uncollectibles		
905	Misc. Customer Accounts		
	Subtotal	0	
Customer Services & Info.			
907	Supervision		
908	Customer assistance		
909	Information and instruction		
910	Miscellaneous		
	Subtotal	0	

PSE Form RS-5

Big Sandy RECC
Expense Account Data
January 01, 2009 Thru December 31, 2009

Acct. No.	Description	Total	Comments
Sales			
911	Supervision		
912	Demonstration and selling		
913	Advertising		
916	Miscellaneous		
	Subtotal	0	
Depreciation			
403.6	Distribution depreciation		
403.7	General plant depreciation		
	Transmission Depreciation		
	Subtotal	0	
Taxes			
408	Property Taxes		
408	Other Taxes		
	Subtotal	0	
Administration and General			
920	Administration and general salaries		
921	Office supplies		
922	Administration expenses transferred		
923	Outside services		
924	Property insurance		
925	Injuries and damages		
926	Employee pension and benefits		
927	Franchise requirements		
928	Regulatory commission expense		
929	Duplicate charges		
930.1	General advertising expenses		
930.2	Dues		
426.10	General Miscellaneous-Donations		
930.30	General Miscellaneous Expense-Dir Exp		
930.41	General Miscellaneous Expense		
930.42	General Miscellaneous Expense		
930.43	EmployeeTraining/Education		
930.44	General Miscellaneous Expense		
931	Rents		
932	Maintenance of general plant		
	Subtotal	0	

Please provide a description of what is included in the following accounts:

587 Operations - Customer's premise ______________________________

588 Miscellaneous distribution ______________________________

598 Miscellaneous maintenance ______________________________

Utility	**Big Sandy RECC**
Begin Date	01/01/09
End Date	12/31/09

PSE FORM RS-6

Big Sandy RECC

Service Transformer Capacity

kVA Size	Number Installed
1.5	-
3.0	-
5.0	-
7.5	-
10.0	-
15.0	-
25.0	-
37.5	-
45.0	-
50.0	-
75.0	-
100.0	-
112.5	-
150.0	-
167.0	-
225.0	-
250.0	-
300.0	-
333.0	-
500.0	-
667.0	-
750.0	-
1,000.0	-
1,500.0	-
2,000.0	-
Others	-
Totals	0

Note: Use either the number of installed or purchased transformers, but installed is preferred.

PSE FORM RS-6

Big Sandy RECC

Miles of Primary Line

Conductor Description		Miles
All Overhead	1PH	0
4 ACSR or 6 CU	VPH	0
2 ACSR or 4 CU	VPH	0
1/0 ACSR or 2 CU	VPH	0
2/0 ACSR or 1/0 CU	VPH	0
3/0 ACSR or 1/0 CU	VPH	0
4/0 ACSR or 2/0 CU	VPH	0
4 ACSR or 6 CU	3PH	0
2 ACSR or 4 CU	3PH	0
1/0 ACSR or 2 CU	3PH	0
2/0 ACSR or 1/0 CU	3PH	0
3/0 ACSR or 1/0 CU	3PH	0
4/0 ACSR or 2/0 CU	3PH	0
267 ACSR	3PH	0
336 ACSR	3PH	0
397 ACSR	3PH	0
477 ACSR	3PH	0
All Underground	1PH	0
1/0 URD	VPH	0
4/0 URD	VPH	0
500 MCM URD	VPH	0
750 MCM URD	VPH	0
1/0 URD	3PH	0
4/0 URD	3PH	0
500 MCM URD	3PH	0
750 MCM URD	3PH	0
		0
Total		0

Rebecca Witt

From:	Cuellar, Marilyn [cuellarm@powersystem.org] on behalf of Macke, Rich [macker@powersystem.org]
Sent:	Thursday, February 11, 2010 6:31 PM
To:	Mark Stallons
Subject:	Retail Rate and Cost of Service Study - Availability Survey
Attachments:	Availability Survey.xls

Attached is an availability survey we will be using to schedule an on-site visit with your cooperative. Please complete the survey at your earliest convenience and return it to my assistant, Marilyn Cuellar, at psemn2@powersystem.org. She will then follow-up to schedule the on-site meeting.

Best Regards,

Rich Macke

Power System Engineering, Inc.
Office: 763-783-5349
Mobile: 612-817-3462
Fax: 763-755-7028
macker@powersystem.org
www.powersystem.org

Retail Rate and Cost of Service Study
Availability Survey

In an effort to schedule on-site visits with each cooperative, we are asking that you complete this survey in regard to your availability. We believe that these meetings will help us understand the objectives and goals of your cooperative as they relate to both wholesale and retail rates.

Agenda for the on-site meeting:
-Discuss the project process, responsibilities and objectives.
-Discuss the project schedule and deliverables.
-Review the data request and status.

We expect that the meeting will take approximately one-two hours.

Please place an **"X"** in each box below reflecting times that the majority of your cooperative's key staff in regard to this project are available. We will then follow-up to schedule the on-site meeting.

Time	1-Mar Monday	2-Mar Tuesday	3-Mar Wednesday	4-Mar Thursday	5-Mar Friday
Morning					
Afternoon					

Time	8-Mar Monday	9-Mar Tuesday	10-Mar Wednesday	11-Mar Thursday	12-Mar Friday
Morning					
Afternoon					

Please provide the contact information of the individual that PSE can work with to schedule the on-site meeting.

Cooperative:	**Name**
Contact Name:	**Name**
Contact's Phone Number:	**Phone Number**
Contact's e-mail:	**E-mail**

Rebecca Witt

From: Laslie, Jeffrey [lasliej@powersystem.org]
Sent: Sunday, February 28, 2010 10:34 PM
To: Mark Stallons
Cc: cobbk@powersystem.org
Subject: Rate Study Meeting

Dear Mark,

As part of the East Kentucky rate study, we are meeting with each member cooperative to discuss the study, the timetable, the data request, and solicit input from you and your staff. I was unable to reach you last week to set up a meeting and was hoping you could let me know possible times you and/or appropriate staff members would be available. I am available Monday through Wednesday next week and this Thursday afternoon. I will be out of the office Monday and Tuesday, but will be checking email. Also, please feel free to call my cell and leave a message or call the office where Kathy will be glad to help you.

I look forward to hearing from you.

Thanks,
Jeff

Jeff Laslie
Power System Engineering, Inc.
Phone: 317-322-5906
Fax: 317-322-5924
Cell: 317-696-0820
lasliej@powersystem.org

Rebecca Witt

From: Laslie, Jeffrey [lasliej@powersystem.org]
Sent: Monday, March 01, 2010 9:04 AM
To: Mark Stallons
Subject: RE: Rate Study Meeting

Mark,

The afternoon on March 8 will work for me. Is 1:30 OK to start?

Thanks,
Jeff

Jeff Laslie
Power System Engineering, Inc.
Phone: 317-322-5906
Fax: 317-322-5924
Cell: 317-696-0820
lasliej@powersystem.org

From: Mark Stallons [mailto:mstallons@owenelectric.com]
Sent: Monday, March 01, 2010 8:24 AM
To: Laslie, Jeffrey
Subject: RE: Rate Study Meeting

Jeff:

Will the afternoon of Monday March 8th or the afternoon of Wednesday March 10th work for you? Mike Cobb, SVP of Member services and Marketing, Rebecca Witt, SVP of Corporate Services, and I are planning to attend.

Thanks,

Mark

Climate Change Regulation and Legislation must be ☑ Fair. ☑ Affordable. ☑ Achievable.

Go to www.ourenergy.coop *to make your voice heard.*

Mark A. Stallons
President & CEO
Owen Electric Cooperative
8205 Hwy 127N PO Box 400
Owenton, KY 40359
Tel: 502-563-3500
Fax: 502-484-2663

From: Laslie, Jeffrey [mailto:lasliej@powersystem.org]
Sent: Sunday, February 28, 2010 10:34 PM
To: Mark Stallons
Cc: cobbk@powersystem.org
Subject: Rate Study Meeting

Dear Mark,

As part of the East Kentucky rate study, we are meeting with each member cooperative to discuss the study, the timetable, the data request, and solicit input from you and your staff. I was unable to reach you last week to set up a meeting and was hoping you could let me know possible times you and/or appropriate staff members would be available. I am available Monday through Wednesday next week and this Thursday afternoon. I will be out of the office Monday and Tuesday, but will be checking email. Also, please feel free to call my cell and leave a message or call the office where Kathy will be glad to help you.

I look forward to hearing from you.

Thanks,
Jeff

Jeff Laslie
Power System Engineering, Inc.
Phone: 317-322-5906
Fax: 317-322-5924
Cell: 317-696-0820
lasliej@powersystem.org

√ **Rebecca Witt**

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Friday, March 05, 2010 4:18 PM
To: Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; Dan Brewer (E-mail); Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); bprather@farmersrecc.com; Wayne Davis; Jerry Carter; cperry@fme.coop; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; Carol Wright; Mark Keene; rodneychrisman@jacksonenergy.com; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Cheryl Thomas; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; Nicky Rapier; J. Edward Boone (E-mail); randyb@srelectric.com; debbiem; gay; denise@shelbyenergy.com; Allen Anderson; Stephen Johnson; Ruby Patterson; Amy Acton; Barry Myers (E-mail); John Patterson; abeard@tcrecc.com
Cc: jimadkins25@aol.com; Jim Lamb; Tony Campbell; Stacy Barker; John Twitchell; Craig Johnson; Denver York; *forward to davismart at FTB*; David Eames
Subject: Invitation Reminder - Rate Design Study - March 12th Meeting

Ladies and Gentlemen:

I have a general description of the agenda for next Friday's meeting with Power System Engineering. The first part of the meeting will be the delayed "kick-off" session with Power System – which includes an overview of the work and how Power System will approach it. The second part of the meeting will be a status update on the project. Several of you have indicated that you will be attending, and I thank you for your response.

So this is also a reminder. Because lunch will be provided, I need to know by the close of business on Wednesday, March 10, 2010 how many will be attending from your cooperative. The March 12, 2010 meeting will start at 10:00 a.m. and will be held in the Board Room. I expect the meeting will wrap up by 2:30 p.m.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

Rebecca Witt

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Monday, March 08, 2010 9:24 AM
To: Rebecca Witt
Cc: Mark Stallons; Mike Cobb
Subject: RE: Invitation Reminder - Rate Design Study - March 12th Meeting

Thank you.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

-----Original Message-----
From: Rebecca Witt [mailto:rwitt@owenelectric.com]
Sent: Monday, March 08, 2010 9:23 AM
To: Isaac Scott
Cc: Mark Stallons; Mike Cobb
Subject: RE: Invitation Reminder - Rate Design Study - March 12th Meeting

Isaac,

Mark and I will be attending for Owen. See you on Fri.,

Becky

From: Isaac Scott [mailto:isaac.scott@ekpc.coop]
Sent: Friday, March 05, 2010 4:18 PM
To: Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; Dan Brewer (E-mail); Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); bprather@farmersrecc.com; Wayne Davis; Jerry Carter; cperry@fme.coop; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; Carol Wright; Mark Keene; rodneychrisman@jacksonenergy.com; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Cheryl Thomas; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; Nicky Rapier; J. Edward Boone (E-mail); randyb@srelectric.com; debbiem; gay; denise@shelbyenergy.com; Allen Anderson; Stephen Johnson; Ruby Patterson; Amy Acton; Barry Myers (E-mail); John Patterson; abeard@tcrecc.com
Cc: jimadkins25@aol.com; Jim Lamb; Tony Campbell; Stacy Barker; John Twitchell; Craig Johnson; Denver York; forward to davismart at FTB; David Eames
Subject: Invitation Reminder - Rate Design Study - March 12th Meeting

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P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

Rebecca Witt

From: Mike Cobb
Sent: Tuesday, March 23, 2010 10:34 AM
To: Rebecca Witt
Cc: Judy Osborne; Mark Stallons
Subject: Rate information for PSE
Attachments: BILL RATE STUDY RS 3 incl all rates.zip; 2009 ENV. SURCHARGE AND FUEL ADJ FACTORS.xls; BILL RATE STUDY RS 4 OUTDOOR LIGHTS.xls.xlsx; EKP WORKSHEET MONTHLY REVENUE.xls; Rate Descriptions.xls

Becky,

Here is everything they asked for except for the three sets of rates that were billed during 2009 that you need to supply. (I assume they need both the rates and effective dates of each). Please forward these to Jeffrey Laslie at PSE along with your file when ready.

Also, please send all this stuff to Ann Wood at EKPC for their current rate case study as well.

Thanks,
Mike

Michael L. Cobb
Owen Electric Cooperative, Inc.
8205 Hwy 127 N.
Owenton, Kentucky 40359
502/563-3533

PSE Rate Study Revenue Data Request

Unit Sales and Revenue Data by Month by Rate Class
Data for Jan 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1] (kWh)	Energy (kWh) Sales: Billed[2] (kWh)	Energy (kWh) Sales: Submetered (kWh)	Demand (kW) Sales: Metered (kW)	Demand (kW) Sales: Billed[3] (kW)	Revenues: Base Rate[4] ($)	Revenues: FCA ($)	Revenues: Environmental Surcharge ($)	Revenues: Total ($)
Rate 1	Schedule 1-Residential			82,291,735	82,291,735	n/a			6,498,763	1,105,346	550,347	8,154,456
Rate 3	Schedule 1-Small Commercial			4,349,048	4,349,048	n/a	8,798	8,798	341,187	58,493	29,035	428,715
Rate 4	Schedule II-Large Commercial			13,519,797	13,519,797	n/a	40,188	41,088	963,908	181,679	82,191	1,227,778
Rate 5	Primary Metered			80,400	80,400	n/a	2,839	2,839	56,455	10,806	4,823	72,084
Rate 6	Outdoor Light Only					n/a			132		1,514	1,646
Rate 9	Schedule XI- LPB1			5,830,608	5,830,608	n/a	13,388	13,388	371,852	78,363	32,280	482,495
Rate 10	ETS Off-Peak			6,994	6,994	n/a			316	91	29	436
Rate 12	Schedule XIV LPB			949,665	949,665	n/a	2,517	2,517	69,830	10,989	5,795	86,614
Rate 13	Scheudle XIII-LPB2			9,721,225	9,721,225	n/a	16,586	16,586	437,865	129,897	40,709	608,471
Rate 20	Large Commercial Time-of-Day			5,065,440	5,065,440	n/a			21,491	4,121		25,612
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,807		443,672	443,672							48,820
	Rate 2	1,478		84,145	84,145							11,738
	Rate 3	79		4,503	4,503							761
	Rate 4	7		399	399							79
	Rate 6	133		7,636	7,636							907
	Rate 7	51		2,907	2,907							431
	Rate 8	5		285	285							51
	Rate 21	2,607		99,211	99,211							23,300
	Rate 22	353		13,599	13,599							4,797
	Rate 31	7		280	280							85
	Rate 32	14		560	560							235
	Rate 33	7		498	498							100
	Rate 34	4		304	304							78
	Rate 35	15		2,310	2,310							319
	Rate 36	5		770	770							130
	Rate 41	12		448	448							127
	Rate 42	6		240	240							96
	Rate 43	18		1,494	1,494							257
	Rate 44	7		581	581							133
	Rate 45	61		9,394	9,394							1,134
	Rate 46	10		1,540	1,540							233
	Rate 51	290		11,600	11,600							2,861
	Rate 52	168		6,680	6,680							1,956
TOTAL		13,144		122,507,968			84,316	85,216	8,761,799	1,579,785		11,186,935

Notes

1. For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2. *For use if kWh billed is different from kWh metered due to kWh minimums*
3. kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4. Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request

Unit Sales and Revenue Data by Month by Rate Class
Data for Feb 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	Three Phase	Energy (kWh) Sales Metered[1]	Billed[2]	Submetered	Demand (kW) Sales Metered	Billed[3]	Revenues Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
Rate 1	Schedule 1-Residential			82,244,810	82,244,810	n/a			6,495,654	415,069	518,492	7,429,215
Rate 3	Schedule 1-Small Commercial			4,456,989	4,456,989	n/a	8,921	8,921	349,217	22,498	27,988	399,703
Rate 4	Schedule II-Large Commercial			14,381,317	14,381,317	n/a	38,472	38,472	1,004,634	72,573	80,088	1,157,295
Rate 5	Primary Metered			1,121,400	1,121,400	n/a	4,507	4,507	82,052	5,663	6,517	94,232
Rate 6	Outdoor Light Only					n/a			132		1,498	1,630
Rate 9	Schedule XI- LPB1			5,534,733	5,534,733	n/a	11,835	11,835	327,286	27,950	26,394	381,630
Rate 10	ETS Off-Peak			6,129	6,129	n/a			277	30	23	330
Rate 12	Schedule XIV LPB			1,009,480	1,009,480	n/a	2,522	2,522	71,138	4,431	5,615	81,184
Rate 13	Scheudle XIII-LPB2			10,149,576	10,149,576	n/a	16,930	16,930	462,642	50,480	38,125	551,247
Rate 20	Large Commercial Time-of-Day			301,776	301,776	n/a			20,928	1,524		22,452
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,767		442,044	442,044							44,920
	Rate 2	1,472		83,800	83,800							10,985
	Rate 3	79		4,503	4,503							723
	Rate 4	7		399	399							76
	Rate 6	134		7,558	7,558							834
	Rate 7	51		2,907	2,907							406
	Rate 8	5		285	285							48
	Rate 21	2,616		101,097	101,097							22,898
	Rate 22	353		13,807	13,807							4,756
	Rate 31	7		280	280							82
	Rate 32	14		560	560							230
	Rate 33	7		581	581							112
	Rate 34	4		332	332							83
	Rate 35	15		2,310	2,310							299
	Rate 36	5		770	770							123
	Rate 41	11		432	432							119
	Rate 42	6		240	240							94
	Rate 43	19		1,577	1,577							257
	Rate 44	7		581	581							128
	Rate 45	61		9,394	9,394							1,055
	Rate 46	10		1,540	1,540							220
	Rate 51	300		11,600	11,600							2,764
	Rate 52	184		7,320	7,320							2,081
TOTAL		13,134		119,900,127			83,187	83,187	8,813,960	600,218		10,212,211

Notes
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4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request

Unit Sales and Revenue Data by Month by Rate Class
Data for Mar 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1] (kWh)	Energy (kWh) Sales: Billed[2] (kWh)	Energy (kWh) Sales: Submetered (kWh)	Demand (kW) Sales: Metered (kW)	Demand (kW) Sales: Billed[3] (kW)	Revenues: Base Rate[4] ($)	Revenues: FCA ($)	Revenues: Environmental Surcharge ($)	Revenues: Total ($)
Rate 1	Schedule 1-Residential			62,687,499	6,287,499	n/a			5,022,023	407,817	407,419	5,837,259
Rate 3	*Schedule 1-Small Commercial*			3,848,935	3,848,935	n/a	9,075	9,075	303,305	25,060	24,703	353,068
Rate 4	Schedule II-Large Commercial			13,094,070	13,094,070	n/a	38,192	38,192	929,967	85,229	75,277	1,090,473
Rate 5	Primary Metered			1,234,200	1,234,200	n/a	3,976	3,976	87,731	8,035	7,096	102,862
Rate 6	Outdoor Light Only					n/a			132		1,503	1,635
Rate 9	Schedule XI- LPB1			5,322,068	5,322,068	n/a	11,692	11,692	326,446	34,647	26,757	387,850
Rate 10	ETS Off-Peak			4,394	4,394	n/a			199	27	17	243
Rate 12	Schedule XIV LPB			1,000,869	1,000,869	n/a	2,496	2,496	71,662	5,656	5,729	83,047
Rate 13	Scheudle XIII-LPB2			9,131,538	9,131,538	n/a	16,325	16,325	416,016	58,727	35,179	509,922
Rate 20	*Large Commercial Time-of-Day*			258,408	258,408	n/a			17,970	1,682		19,652
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,755		441,812	441,812							45,583
	Rate 2	1,467		82,780	82,780							10,978
	Rate 3	78		4,446	4,446							721
	Rate 4	7		399	399							76
	Rate 6	130		7,410	7,410							829
	Rate 7	51		2,901	2,901							410
	Rate 8	5		285	285							49
	Rate 21	2,617		102,617	102,617							23,384
	Rate 22	355		13,697	13,697							4,738
	Rate 31	7		280	280							83
	Rate 32	14		560	560							231
	Rate 33	7		581	581							113
	Rate 34	4		332	332							83
	Rate 35	15		2,310	2,310							303
	Rate 36	5		770	770							124
	Rate 41	11		440	440							122
	Rate 42	6		240	240							95
	Rate 43	19		1,577	1,577							260
	Rate 44	7		581	581							129
	Rate 45	61		9,394	9,394							1,069
	Rate 46	14		1,540	1,540							262
	Rate 51	290		11,587	11,587							2,778
	Rate 52	184		7,320	7,320							2,091
TOTAL		13,109		97,275,840			81,756	81,756	7,175,451	626,880		8,480,522

Notes

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PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Apr 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1] (kWh)	Energy (kWh) Sales: Billed[2] (kWh)	Energy (kWh) Sales: Submetered (kWh)	Demand (kW) Sales: Metered (kW)	Demand (kW) Sales: Billed[3] (kW)	Revenues: Base Rate[4] ($)	Revenues: FCA ($)	Revenues: Environmental Surcharge ($)	Revenues: Total ($)
Rate 1	Schedule 1-Residential			50,360,899	50,360,899	n/a			4,220,783	459,325	344,655	5,024,763
Rate 3	Schedule 1-Small Commercial			3,784,328	3,784,328	n/a	8,380	8,380	304,998	34,204	24,849	364,051
Rate 4	Schedule II-Large Commercial			12,680,464	12,680,464	n/a	40,612	40,612	940,007	115,754	76,597	1,132,358
Rate 5	Primary Metered			1,424,400	1,424,400	n/a	4,594	4,594	100,135	13,005	8,203	121,343
Rate 6	Outdoor Light Only					n/a			113		1,590	1,703
Rate 9	Schedule XI- LPB1			5,649,724	5,649,724	n/a	11,726	11,726	327,517	51,582	27,479	406,578
Rate 10	ETS Off-Peak			3,129	3,129	n/a			147	27	13	187
Rate 12	Schedule XIV LPB			989,045	989,045	n/a	2,477	2,477	71,034	7,825	5,717	84,576
Rate 13	Scheudle XIII-LPB2			8,996,511	8,996,511	n/a	16,182	16,182	411,096	81,221	35,693	528,010
Rate 20	Large Commercial Time-of-Day			249,456	249,456	n/a			17,765	2,278		20,043
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,721		440,513	440,513							49,376
	Rate 2	1,462		81,833	81,833							11,758
	Rate 3	79		4,503	4,503							788
	Rate 4	7		399	399							82
	Rate 6	130		7,410	7,410							900
	Rate 7	50		2,850	2,850							436
	Rate 8	5		285	285							53
	Rate 21	2,659		100,545	100,545							24,658
	Rate 22	351		13,712	13,712							5,083
	Rate 31	7		280	280							89
	Rate 32	14		560	560							247
	Rate 33	7		581	581							121
	Rate 34	4		332	332							89
	Rate 35	15		2,310	2,310							328
	Rate 36	5		770	770							134
	Rate 41	21		613	613							182
	Rate 42	6		240	240							101
	Rate 43	21		1,718	1,718							306
	Rate 44	8		611	611							146
	Rate 45	61		9,394	9,394							1,160
	Rate 46	14		1,540	1,540							320
	Rate 51	290		11,600	11,600							2,991
	Rate 52	184		7,320	7,320							2,244
TOTAL		13,121		84,827,875			83,971	83,971	6,393,595	765,221		7,785,204

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PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for May 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	No. of Consumers Three Phase	Energy (kWh) Sales Metered[1] (kWh)	Energy (kWh) Sales Billed[2] (kWh)	Energy (kWh) Sales Submetered (kWh)	Demand (kW) Sales Metered (kW)	Demand (kW) Sales Billed[3] (kW)	Revenues Base Rate[4] ($)	Revenues FCA ($)	Revenues Environmental Surcharge ($)	Revenues Total ($)
Rate 1	Schedule 1-Residential			45,778,062	45,778,062	n/a			3,995,924	465,941	331,666	4,793,531
Rate 3	Schedule 1-Small Commercial			3,616,036	3,616,036	n/a	8,600	8,600	302,874	36,452	25,134	364,460
Rate 4	Schedule II-Large Commercial			12,458,551	12,458,551	n/a	41,525	41,525	971,718	126,932	80,367	1,179,017
Rate 5	Primary Metered			1,616,400	1,616,400	n/a	5,188	5,188	118,193	16,471	9,844	144,508
Rate 6	Outdoor Light Only					n/a			132		1,630	1,762
Rate 9	Schedule XI- LPB1			5,158,093	5,158,093	n/a	11,991	11,991	340,336	52,561	28,721	421,618
Rate 10	ETS Off-Peak			797	797	n/a			38	6	3	47
Rate 12	Schedule XIV LPB			969,945	969,945	n/a	2,557	2,557	76,059	8,539	6,184	90,782
Rate 13	Scheudle XIII-LPB2			8,286,492	8,286,492	n/a	14,400	14,400	428,181	81,668	37,270	547,119
Rate 20	Large Commercial Time-of-Day			261,216	261,216	n/a			20,060	2,662		22,722
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,694		437,945	437,945							49,556
	Rate 2	1,461		83,056	83,056							12,007
	Rate 3	79		4,503	4,503							793
	Rate 4	7		399	399							83
	Rate 6	130		7,410	7,410							907
	Rate 7	50		2,850	2,850							439
	Rate 8	5		285	285							53
	Rate 21	2,709		105,241	105,241							25,860
	Rate 22	366		14,907	14,907							5,514
	Rate 31	12		480	480							152
	Rate 32	14		560	560							248
	Rate 33	7		581	581							122
	Rate 34	4		332	332							90
	Rate 35	16		2,346	2,346							335
	Rate 36	5		770	770							135
	Rate 41	24		924	924							275
	Rate 42	6		240	240							101
	Rate 43	22		1,826	1,826							327
	Rate 44	8		664	664							159
	Rate 45	62		9,481	9,481							1,181
	Rate 46	16		1,715	1,715							349
	Rate 51	290		11,600	11,600							3,004
	Rate 52	184		7,320	7,320							2,252
TOTAL		13,171		78,841,027			84,261	84,261	6,253,515	791,232		7,669,508

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PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Jun 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	Three Phase	Energy (kWh) Sales Metered[1] (kWh)	Billed[2] (kWh)	Submetered (kWh)	Demand (kW) Sales Metered (kW)	Billed[3] (kW)	Revenues Base Rate[4] ($)	FCA ($)	Environmental Surcharge ($)	Total ($)
Rate 1	Schedule 1-Residential			50,300,883	50,300,883	n/a			4,358,961	331,178	371,525	5,061,664
Rate 3	Schedule 1-Small Commercial			3,542,718	3,542,718	n/a	9,241	9,241	298,739	23,351	25,553	347,643
Rate 4	Schedule II-Large Commercial			12,455,699	12,455,699	n/a	42,478	42,478	976,214	82,070	82,604	1,140,888
Rate 5	Primary Metered			1,692,600	1,692,600	n/a	5,681	5,681	125,083	11,154	10,627	146,864
Rate 6	Outdoor Light Only					n/a			122		1,702	1,824
Rate 9	Schedule XI- LPB1			5,357,970	5,357,970	n/a	11,963	11,963	337,484	35,309	29,078	401,871
Rate 10	ETS Off-Peak			208	208	n/a			10	1	1	12
Rate 12	Schedule XIV LPB			981,784	981,784	n/a	2,735	2,735	76,886	5,600	6,434	88,920
Rate 13	Scheudle XIII-LPB2			7,564,046	7,564,046	n/a	13,550	13,550	420,096	49,847	36,656	506,599
Rate 20	Large Commercial Time-of-Day			303,240	303,240	n/a			23,789	1,998		25,787
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,662		434,400	434,400							47,566
	Rate 2	1,451		82,544	82,544							11,631
	Rate 3	79		4,503	4,503							777
	Rate 4	7		399	399							81
	Rate 6	130		7,410	7,410							880
	Rate 7	50		2,850	2,850							428
	Rate 8	5		285	285							52
	Rate 21	2,739		105,776	105,776							25,634
	Rate 22	364		14,962	14,962							5,491
	Rate 31	13		520	520							163
	Rate 32	14		560	560							246
	Rate 33	7		581	581							120
	Rate 34	4		332	332							89
	Rate 35	15		2,310	2,310							322
	Rate 36	5		770	770							132
	Rate 41	23		920	920							271
	Rate 42	6		240	240							101
	Rate 43	22		1,826	1,826							320
	Rate 44	8		664	664							156
	Rate 45	62		9,548	9,548							1,155
	Rate 46	16		1,848	1,848							363
	Rate 51	290		11,600	11,600							2,962
	Rate 52	185		7,320	7,320							2,225
TOTAL		13,157		82,891,316			85,648	85,648	6,617,384	540,508		7,823,237

Notes

1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Jul 2009

Rate Code	Applicable Rate Schedule	No. of Consumers		Energy (kWh) Sales			Demand (kW) Sales		Revenues			
		Single Phase	Three Phase	Metered[1]	Billed[2]	Submetered	Metered	Billed[3]	Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
Rate 1	Schedule 1-Residential			62,025,037	62,025,037	n/a			5,581,305	215,027	438,869	6,235,201
Rate 3	Schedule 1-Small Commercial			4,025,574	4,025,574	n/a	9,496	9,496	353,807	13,990	27,914	395,711
Rate 4	Schedule II-Large Commercial			13,161,966	13,161,966	n/a	43,530	43,530	1,028,279	45,559	80,161	1,153,999
Rate 5	Primary Metered			2,112,000	2,112,000	n/a	6,062	6,062	151,108	7,329	11,819	170,256
Rate 6	Outdoor Light Only					n/a			132		1,987	2,119
Rate 9	Schedule XI- LPB1			5,562,509	5,562,509	n/a	12,194	12,194	356,452	19,302	28,031	403,785
Rate 10	ETS Off-Peak					n/a						
Rate 12	Schedule XIV LPB			1,062,339	1,062,339	n/a	2,838	2,838	78,573	3,228	6,102	87,903
Rate 13	Scheudle XIII-LPB2			8,696,971	8,696,971	n/a	15,251	15,251	409,055	30,178	32,767	472,000
Rate 20	Large Commercial Time-of-Day			386,088	386,088	n/a			30,396	1,340	8	31,744
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,634		433,816	433,816							61,671
	Rate 2	1,451		82,351	82,351							14,219
	Rate 3	79		4,486	4,486							912
	Rate 4	7		399	399							93
	Rate 6	131		8,835	8,835							1,306
	Rate 7	50		2,850	2,850							526
	Rate 8	5		285	285							61
	Rate 21	2,800		109,179	109,179							26,799
	Rate 22	364		13,884	13,884							5,050
	Rate 31	13		520	520							166
	Rate 32	14		560	560							244
	Rate 33	7		581	581							121
	Rate 34	4		332	332							88
	Rate 35	15		2,310	2,310							323
	Rate 36	5		770	770							131
	Rate 41	23		920	920							275
	Rate 42	6		240	240							100
	Rate 43	22		1,826	1,826							322
	Rate 44	8		664	664							155
	Rate 45	62		9,548	9,548							1,155
	Rate 46	16		1,848	1,848							359
	Rate 51	296		11,696	11,696							3,687
	Rate 52	183		7,280	7,280							2,737
TOTAL		13,195		97,727,664			89,371	89,371	7,989,107	335,953		9,073,218

Notes

1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
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3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Aug 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1]	Energy (kWh) Sales: Billed[2]	Energy (kWh) Sales: Submetered	Demand (kW) Sales: Metered	Demand (kW) Sales: Billed[3]	Revenues: Base Rate[4]	Revenues: FCA	Revenues: Environmental Surcharge	Revenues: Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
Rate 1	Schedule 1-Residential			62,459,556	62,459,556	n/a			5,907,975	-21,839	465,517	6,351,653
Rate 3	Schedule 1-Small Commercial			4,202,306	4,202,306	n/a	9,739	9,739	383,845	-1,471	30,309	412,683
Rate 4	Schedule II-Large Commercial			13,812,569	13,812,569	n/a	42,278	42,278	1,089,835	-4,834	84,642	1,169,643
Rate 5	Primary Metered			2,280,000	2,280,000	n/a	6,162	6,162	164,583	-798	12,759	176,544
Rate 6	Outdoor Light Only					n/a			121		2,157	2,278
Rate 9	Schedule XI- LPB1			5,671,114	5,671,114	n/a	12,155	12,155	356,415	-1,984	27,610	382,041
Rate 10	ETS Off-Peak					n/a						
Rate 12	Schedule XIV LPB			1,049,556	1,049,556	n/a	2,667	2,667	77,218	-321	5,990	82,887
Rate 13	Scheudle XIII-LPB2			9,579,768	9,579,768	n/a	15,781	15,781	444,830	-3,353	34,391	475,868
Rate 20	Large Commercial Time-of-Day			496,656	496,656	n/a			39,612	-174	3,072	42,510
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,604		431,538	431,538							63,970
	Rate 2	1,440		83,175	83,175							14,807
	Rate 3	80		4,477	4,477							937
	Rate 4	7		399	399							96
	Rate 6	132		7,494	7,494							1,199
	Rate 7	50		2,850	2,850							543
	Rate 8	5		285	285							63
	Rate 21	2,832		109,215	109,215							27,628
	Rate 22	366		14,221	14,221							5,275
	Rate 31	13		520	520							170
	Rate 32	14		560	560							248
	Rate 33	7		581	581							125
	Rate 34	4		332	332							90
	Rate 35	15		2,310	2,310							339
	Rate 36	5		770	770							136
	Rate 41	23		920	920							281
	Rate 42	6		240	240							102
	Rate 43	22		1,826	1,826							335
	Rate 44	8		664	664							159
	Rate 45	62		9,548	9,548							1,220
	Rate 46	16		1,848	1,848							372
	Rate 51	300		12,000	12,000							3,866
	Rate 52	183		7,280	7,280							2,787
TOTAL		13,194		100,244,578			88,782	88,782	8,464,434	-34,774		9,220,855

Notes

1. *For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period*
2. For use if kWh billed is different from kWh metered due to kWh minimums
3. kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4. Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Sep 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1] (kWh)	Energy (kWh) Sales: Billed[2] (kWh)	Energy (kWh) Sales: Submetered (kWh)	Demand (kW) Sales: Metered (kW)	Demand (kW) Sales: Billed[3] (kW)	Revenues: Base Rate[4] ($)	Revenues: FCA ($)	Revenues: Environmental Surcharge ($)	Revenues: Total ($)
Rate 1	Schedule 1-Residential			57,812,426	57,812,426	n/a			5,855,689	59,514	469,013	6,384,216
Rate 3	Schedule 1-Small Commercial			3,988,486	3,988,486	n/a	9,308	9,308	393,538	4,108	31,572	429,218
Rate 4	Schedule II-Large Commercial			13,721,856	13,721,856	n/a	43,899	43,899	1,209,832	14,131	95,661	1,319,624
Rate 5	Primary Metered			2,448,000	2,448,000	n/a	6,554	6,554	197,209	2,521	15,599	215,329
Rate 6	Outdoor Light Only					n/a			132		2,166	2,298
Rate 9	Schedule XI- LPB1			6,040,725	6,040,725	n/a	12,694	12,694	440,626	6,222	34,899	481,747
Rate 10	ETS Off-Peak					n/a						
Rate 12	Schedule XIV LPB			1,092,845	1,092,845	n/a	2,797	2,797	95,879	990	7,565	104,434
Rate 13	Scheudle XIII-LPB2			10,097,125	10,097,125	n/a	16,168	16,168	572,517	10,400	45,526	628,443
Rate 20	Large Commercial Time-of-Day			277,104	277,104	n/a			25,184	285	1,989	27,458
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,550		428,023	428,023							63,823
	Rate 2	1,428		81,033	81,033							14,579
	Rate 3	78		4,414	4,414							929
	Rate 4	7		399	399							96
	Rate 6	132		7,429	7,429							1,197
	Rate 7	50		2,850	2,850							546
	Rate 8	5		285	285							63
	Rate 21	2,872		110,418	110,418							28,163
	Rate 22	381		14,686	14,686							5,465
	Rate 31	13		520	520							170
	Rate 32	14		560	560							249
	Rate 33	7		581	581							126
	Rate 34	4		332	332							91
	Rate 35	15		2,310	2,310							342
	Rate 36	5		770	770							137
	Rate 41	23		920	920							282
	Rate 42	7		185	185							92
	Rate 43	22		1,798	1,798							332
	Rate 44	7		581	581							140
	Rate 45	62		9,548	9,548							1,233
	Rate 46	16		1,848	1,848							374
	Rate 51	300		12,000	12,000							3,882
	Rate 52	183		7,280	7,280							2,797
TOTAL		13,181		96,167,337			91,420	91,420	8,790,606	98,171		9,717,875

Notes

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4. Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Oct 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	No. of Consumers Three Phase	Energy (kWh) Sales Metered[1] (kWh)	Energy (kWh) Sales Billed[2] (kWh)	Energy (kWh) Sales Submetered (kWh)	Demand (kW) Sales Metered (kW)	Demand (kW) Sales Billed[3] (kW)	Revenues Base Rate[4] ($)	Revenues FCA ($)	Revenues Environmental Surcharge ($)	Revenues Total ($)
Rate 1	Schedule 1-Residential			47,108,214	47,108,214	n/a			4,879,009	-492,701	372,366	4,758,674
Rate 3	Schedule 1-Small Commercial			3,700,418	3,700,418	n/a	9,145	9,145	367,630	-38,732	27,916	356,814
Rate 4	Schedule II-Large Commercial			13,851,659	13,851,659	n/a	42,774	42,774	1,208,077	-145,006	88,623	1,151,694
Rate 5	Primary Metered			2,571,600	2,571,600	n/a	6,911	6,911	207,219	-26,925	15,036	195,330
Rate 6	Outdoor Light Only					n/a			132		2,191	2,323
Rate 9	Schedule XI- LPB1			5,658,847	5,658,847	n/a	12,210	12,210	430,664	-59,248	30,939	402,355
Rate 10	ETS Off-Peak			829	829	n/a			45	-9	3	39
Rate 12	Schedule XIV LPB			632,306	632,306	n/a	1,848	1,848	64,452	-5,238	4,933	64,147
Rate 13	Scheudle XIII-LPB2			9,614,292	9,614,292	n/a	16,012	16,012	555,775	-100,662	37,911	493,024
Rate 20	Large Commercial Time-of-Day			244,288	244,288	n/a			22,377	-2,558	1,651	21,470
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,498		424,066	424,066							58,552
	Rate 2	1,414		80,446	80,446							13,550
	Rate 3	75		4,275	4,275							851
	Rate 4	7		399	399							92
	Rate 6	131		7,395	7,395							1,107
	Rate 7	50		2,820	2,820							508
	Rate 8	5		285	285							60
	Rate 21	2,901		112,298	112,298							27,240
	Rate 22	390		14,160	14,160							5,122
	Rate 31	14		560	560							177
	Rate 32	14		560	560							242
	Rate 33	7		581	581							119
	Rate 34	4		332	332							87
	Rate 35	15		2,310	2,310							315
	Rate 36	5		770	770							129
	Rate 41	28		1,645	1,645							491
	Rate 42	6		240	240							99
	Rate 43	20		1,660	1,660							288
	Rate 44	7		581	581							134
	Rate 45	61		9,394	9,394							1,105
	Rate 46	17		2,002	2,002							376
	Rate 51	321		12,605	12,605							3,933
	Rate 52	183		7,016	7,016							2,615
TOTAL		13,173		84,068,853		0	88,900	88,900	7,735,380	-871,079		7,563,062

Notes
1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period.
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4 Outdoor Lighting revenues should be shown as separate rate class.

PSE Rate Study Revenue Data Request

Unit Sales and Revenue Data by Month by Rate Class
Data for Nov 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1]	Energy (kWh) Sales: Billed[2]	Energy (kWh) Sales: Submetered	Demand (kW) Sales: Metered	Demand (kW) Sales: Billed[3]	Revenues: Base Rate[4]	Revenues: FCA	Revenues: Environmental Surcharge	Revenues: Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
Rate 1	Schedule 1-Residential			46,171,660	46,171,660	n/a			4,794,104	-360,409	292,801	4,726,496
Rate 3	Schedule 1-Small Commercial			3,400,980	3,400,980	n/a	8,664	8,664	340,171	-26,597	20,727	334,301
Rate 4	Schedule II-Large Commercial			12,221,506	12,221,506	n/a	38,846	38,846	1,076,980	-95,556	63,651	1,045,075
Rate 5	Primary Metered			2,264,400	2,264,400	n/a	6,742	6,742	186,284	-17,708	10,928	179,504
Rate 6	Outdoor Light Only					n/a			81		1,720	1,801
Rate 9	Schedule XI- LPB1			5,631,368	5,631,368	n/a	11,062	11,062	419,653	-44,037	24,340	399,956
Rate 10	ETS Off-Peak			2,365	2,365	n/a			130	-19	7	118
Rate 12	Schedule XIV LPB			594,760	594,760	n/a	1,527	1,527	54,899	-3,619	3,323	54,603
Rate 13	Scheudle XIII-LPB2			9,158,786	9,158,786	n/a	15,874	15,874	532,130	-71,622	29,841	490,349
Rate 20	Large Commercial Time-of-Day			256,552	256,552	n/a			21,180	-2,006	1,242	20,416
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,457		421,456	421,456							57,399
	Rate 2	1,414		80,352	80,352							13,746
	Rate 3	75		4,234	4,234							853
	Rate 4	7		399	399							93
	Rate 6	129		7,259	7,259							1,106
	Rate 7	48		2,736	2,736							-209
	Rate 8	5		285	285							61
	Rate 21	2,939		113,380	113,380							27,836
	Rate 22	394		15,238	15,238							5,537
	Rate 31	15		597	597							190
	Rate 32	14		560	560							244
	Rate 33	7		581	581							121
	Rate 34	4		332	332							88
	Rate 35	15		2,310	2,310							321
	Rate 36	5		770	770							131
	Rate 41	28		1,120	1,120							334
	Rate 42	6		240	240							100
	Rate 43	18		1,494	1,494							263
	Rate 44	7		581	581							135
	Rate 45	62		9,481	9,481							1,141
	Rate 46	17		2,002	2,002							381
	Rate 51	313		12,520	12,520							3,940
	Rate 52	174		6,920	6,920							2,598
TOTAL		13,153		80,387,224			82,715	82,715	7,425,612	-621,573		7,369,028

Notes

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4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request

Unit Sales and Revenue Data by Month by Rate Class
Data for Dec 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	Three Phase	Energy (kWh) Sales Metered[1] (kWh)	Billed[2] (kWh)	Submetered (kWh)	Demand (kW) Sales Metered (kW)	Billed[3] (kW)	Revenues Base Rate[4] ($)	FCA ($)	Environmental Surcharge ($)	Total ($)
Rate 1	Schedule 1-Residential			61,208,280	61,208,280	n/a	n/a	n/a	6,165,834	-858,646	60,354	5,367,542
Rate 3	Schedule 1-Small Commercial			3,736,228	3,736,228		9,158	9,158	370,821	-52,460	3,629	321,990
Rate 4	Schedule II-Large Commercial			12,489,310	12,489,310		39,699	39,699	1,100,518	-175,322	10,384	935,580
Rate 5	Primary Metered			1,223,400	1,223,400		4,451	4,451	105,233	-17,177	987	89,043
Rate 6	Outdoor Light Only								132		288	420
Rate 9	Schedule XI- LPB1			6,177,210	6,177,210		13,098	13,098	460,297	-86,728	21,554	395,123
Rate 10	ETS Off-Peak			2,796	2,796				153	-39	1	115
Rate 12	Schedule XIV LPB			550,781	550,781		1,546	1,546	56,859	-5,880	1,254	52,233
Rate 13	Scheudle XIII-LPB2			8,937,506	8,937,506		15,826	15,826	522,244	-125,483	27,819	424,580
Rate 20	Large Commercial Time-of-Day			292,296	292,296				24,989	-4,104	234	21,119
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,403		420,343	420,343							56,500
	Rate 2	1,406		79,970	79,970							13,188
	Rate 3	74		5,612	5,612							1,065
	Rate 4	7		399	399							90
	Rate 6	125		7,125	7,125							1,041
	Rate 7	48		2,736	2,736							483
	Rate 8	5		285	285							59
	Rate 21	2,939		116,046	116,046							27,734
	Rate 22	395		15,437	15,437							5,513
	Rate 31	15		600	600							187
	Rate 32	14		560	560							241
	Rate 33	7		581	581							117
	Rate 34	4		332	332							86
	Rate 35	15		2,310	2,310							307
	Rate 36	5		770	770							126
	Rate 41	29		1,160	1,160							339
	Rate 42	6		240	240							98
	Rate 43	18		1,494	1,494							253
	Rate 44	7		581	581							131
	Rate 45	62		9,471	9,471							1,080
	Rate 46	17		2,002	2,002							369
	Rate 51	313		12,520	12,520							3,862
	Rate 52	174		6,920	6,920							2,555
TOTAL		13,088		95,305,301			83,778	83,778	8,807,080	-1,325,839		7,723,169

Notes

1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Total 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	Three Phase	Energy (kWh) Sales Metered[1]	Billed[2]	Submetered	Demand (kW) Sales Metered	Billed[3]	Revenues Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
		#DIV/0!	#DIV/0!									
Rate 1	Schedule 1-Resident	#DIV/0!	#DIV/0!	710,449,061	654,049,061				63,776,024	1,725,622		70,124,670
Rate 3	Schedule I-Small C	#DIV/0!	#DIV/0!	46,652,046	46,652,046		9,496	108,525	4,110,132	98,896		4,508,357
Rate 4	Schedule II-Large C	#DIV/0!	#DIV/0!	157,848,764	157,848,764		43,530	493,393	12,499,969	303,209		13,703,424
Rate 5	Primary Metered	#DIV/0!	#DIV/0!	20,068,800	20,068,800	#REF!	#REF!	63,667	1,581,285	12,376		1,707,899
Rate 6	Outdoor Light Only	#DIV/0!	#DIV/0!						1,493			21,439
Rate 9	Schedule XI- LPB1	#DIV/0!	#DIV/0!	67,594,969	67,594,969		12,194	146,008	4,495,028	113,939		4,947,049
Rate 10	ETS Off-Peak	#DIV/0!	#DIV/0!	27,641	27,641				1,315	115		1,527
Rate 12	Schedule XIV LPB	#DIV/0!	#DIV/0!	10,883,375	10,883,375		2,838	28,527	864,489	32,200		961,330
Rate 13	Scheudle XIII-LPB2	#DIV/0!	#DIV/0!	109,933,836	109,933,836		15,251	188,885	5,612,447	191,298		6,235,632
Rate 20	Large Commercial 1	#DIV/0!	#DIV/0!	8,392,520	8,392,520				285,741	7,048		300,985
		#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!		#REF!
	YARD LIGHTS:	#DIV/0!	#DIV/0!									
	Rate 1	7,650	#DIV/0!	4,779,285	4,779,285							591,236
	Rate 2	1,945	#DIV/0!	1,325,858	1,325,858							196,498
	Rate 3	189	#DIV/0!	128,817	128,817							22,233
	Rate 4	13	#DIV/0!	10,001	10,001							2,012
	Rate 6	121	#DIV/0!	83,645	83,645							11,262
	Rate 7	56	#DIV/0!	38,496	38,496							5,505
	Rate 8	9	#DIV/0!	5,871	5,871							1,097
	Rate 21	2,525	#DIV/0!	1,169,262	1,169,262							283,459
	Rate 22	581	#DIV/0!	272,919	272,919							84,562
	Rate 31	44	#DIV/0!	22,304	22,304							7,274
	Rate 32	14	#DIV/0!	6,648	6,648							2,743
	Rate 33	8	#DIV/0!	6,610	6,610							1,537
	Rate 34	5	#DIV/0!	5,395	5,395							1,252
	Rate 35	18	#DIV/0!	32,862	32,862							4,447
	Rate 36	6	#DIV/0!	11,550	11,550							1,852
	Rate 41	43	#DIV/0!	21,224	21,224							5,619
	Rate 42	22	#DIV/0!	10,185	10,185							3,280
	Rate 43	19	#DIV/0!	17,368	17,368							3,108
	Rate 44	8	#DIV/0!	7,666	7,666							1,694
	Rate 45	57	#DIV/0!	95,311	95,311							11,605
	Rate 46	19	#DIV/0!	27,202	27,202							4,456
	Rate 51	273	#DIV/0!	120,810	120,810							34,176
	Rate 52	195	#DIV/0!	84,896	84,896							28,289
		174	#DIV/0!	6,920	6,920							2,555
		#DIV/0!	#DIV/0!									
		#DIV/0!	#DIV/0!									
		#DIV/0!	#DIV/0!									
TOTAL		13,152		1,140,145,110			89,371	1,029,005	93,227,923	2,484,703		103,824,824

Notes

1. For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2. For use if kWh billed is different from kWh metered due to kWh minimums
3. kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4. Outdoor Lighting revenues should be shown as separate rate class.

4 Outdoor Lighting revenues should be shown as separate rate class

2009 ENV. SURCHARGE AND FUEL FACTOR

BILL MONTH	SURCHARGE FACTOR	FUEL FACTOR
Jan-09	7.17%	0.01344
Feb-09	7.43%	0.00505
Mar-09	7.41%	0.00651
Apr-09	7.25%	0.00913
May-09	7.31%	0.01019
Jun-09	7.80%	0.00659
Jul-09	7.46%	0.00347
Aug-09	7.79%	-0.00035
Sep-09	7.81%	0.00103
Oct-09	8.33%	-0.01047
Nov-09	6.48%	-0.00782
Dec-09	1.12%	-0.01404

RATE SCHEDULE	(Rate Table) RATE NO.
RESIDENTIAL	1
SMALL COMM. (less than 50 KW)	3
LARGE POWER (greater than 50 KW)	4
LARGE POWER (greater than 50 KW) & primary metered	5
LPC1	7
LPC1A	8
LPB1 (1,000 - 2,499 KW)	9
ETS - Off Peak -Residential	10
LPB1A (2,500 - 4,999 KW)	11
LPB (500 - 999 KW)	12
LPB2 (5000 + KW)	13
Lrg. Power - T.O.D.	20
Lrg. Power - T.O.D. (*linked to Rate 20)	21

PSE Form RS-4

OWEN ELECTRIC COOPERATIVE, INC.
Outdoor Lighting

(1)	(2)	(3)
	No. of Lights	**Estimated Monthly Usage**
		(kWh)
Yard Lights (F-10)		
100 kWh	12,953	518,120
250 kWh	36	2,988
400 kWh	99	15,246
Total	13,088	536,354

Account Number (i.e. acct. 371)	Total
Plant Investment (12/31/09)	-
O&M Expense (1/1/09 to 12/31/09)	-

√ **Rebecca Witt**

From:	Laslie, Jeffrey [lasliej@powersystem.org]
Sent:	Thursday, April 08, 2010 1:12 PM
To:	Rebecca Witt
Cc:	Mark Stallons; macker@powersystem.org
Subject:	EKPC Rate Study Second Data Request
Attachments:	JCL-Witt-4-6-10.doc; Owen RS-7.xlsx

Please see attached.

Thanks,
Jeff

Jeff Laslie
Power System Engineering, Inc.
Phone: 317-322-5906
Fax: 317-322-5924
Cell: 317-696-0820
lasliej@powersystem.org

Via e-mail

April 6, 2010

Ms. Becky Witt
Sr. VP Corporate Services
Owen Electric Cooperative
P.O. Box 400
Owenton, KY 40359-0400

Subject: Rate and Cost of Service Study
Second Set of Data Requests

Dear Becky:

We are enclosing our second set of data requests for the Rate and Cost of Service Study we are conducting for Owen. Also enclosed is a data request form.

Please forward all readily available requested data at your earliest convenience in electronic format whenever possible.

If you should have any questions regarding the data request, please do not hesitate to contact me at (317) 322-5906 or email lasliej@powersystem.org. You may also contact Rich Macke at (763) 783-5349 or email macker@powersystem.org.

Very truly yours,

Jeffrey C. Laslie
Senior Financial Analyst

KY0591018/mmc

cc: Mark Stallons, Owen
Rich Macke, PSE

Enclosures

OWEN ELECTRIC COOPERATIVE
RATE AND COST OF SERVICE STUDY
SECOND SET OF DATA REQUESTS

TEST YEAR: Actual 2009

Item	Data Request	Priority	Data Form Request	Due Date
1	Continuing Property Records (CPR) as of December 31, 2009.	High		4/13/10
2	Information on metering including: a. Metering cost by functionality b. Meter functionality by rate schedule. Please use the provided Excel file **RS-7**.	High	RS-7	4/13/10

Meter Replacement Costs

Meter Type No.	Phase	Units Metered	Time-of-Day [1]	Interval Recording [2]	PSE Model Cost	Owen Electric's Cost [3]
1	Single	kWh	NO	NO	$78	$0
2	Single	kWh	YES	NO	$117	$0
3	Three	kWh	NO	NO	$286	$0
4	Three	kWh and kW	NO	NO	$441	$0
5	Three	kWh, kW, PF/KVAR	NO	NO	$511	$0
6	Three	kWh, kW, PF/KVAR	YES	NO	$546	$0
7	Three	kWh, kW, PF/KVAR	YES	YES	$1,200	$0

[1] Capability to meter energy and/or demand data by defined periods.
[2] Capability to provide coincident demand information (i.e. hourly data).
[3] Please enter the replacement cost including installation for applicable meters used by the coop.

Meter Type by Rate Schedule

Instructions
Please select the meter type number from above that corresponds to meter functionality installed per the applicable rate schedule.

Rate Schedule	PSE Model Meter Type	Owen Electric's Meter Type
Schedule I - Farm and Residential - Rate 1	1	-select-
Schedule I - Small Commercial Single Phase - Rate 3	1	-select-
Schedule I - Small Commercial Three Phase - Rate 3	3	-select-
Schedule II - Large Commercial - Rate 4	5	-select-
Schedule XI - Large Industrial Rate LPB1 - Rate 9	6	-select-
Schedule XIII- Large Industrial Rate LPB2 - Rate 13	6	-select-
Schedule XIV - Large Industrial Rate LPB - Rate 12	6	-select-
Schedule 2-A-Large Power/Commercial Time-of-Day - Rate 20	6	-select-
Schedule ETS Off-Peak - Rate 10	2	-select-

Rebecca Witt

From:	Isaac Scott [isaac.scott@ekpc.coop]
Sent:	Wednesday, April 14, 2010 2:03 PM
To:	Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; Dan Brewer (E-mail); Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); bprather@farmersrecc.com; Wayne Davis; Jerry Carter; cperry@fme.coop; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; Carol Wright; Mark Keene; rodneychrisman@jacksonenergy.com; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Cheryl Thomas; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; Nicky Rapier; J. Edward Boone (E-mail); randyb@srelectric.com; debbiem; gay; denise@shelbyenergy.com; Allen Anderson; Stephen Johnson; Ruby Patterson; Amy Acton; Barry Myers (E-mail); John Patterson; abeard@tcrecc.com
Cc:	jimadkins25@aol.com; Tony Campbell; Stacy Barker; David Eames; John Twitchell; Craig Johnson; Denver York; forward to davismart at FTB
Subject:	Next Meeting with Power System Engineering

Ladies and Gentlemen:

The timetable Power System developed for the Rate Design Study calls for a Status Meeting on May 10th. Power System has asked if this meeting could be held the week before – sometime during the week of May 3rd. The purpose for this meeting is to discuss the wholesale cost of service study results with the Members. In addition, Power System believes that most if not all of the retail cost of service study results will be out to the Members by then and this meeting could allow for a review of general observations, answer questions, etc.

Looking at calendars and other schedules, it appears Tuesday, May 4, 2010 would be a good day for this meeting. We would start at 10:00 a.m. and will plan on having lunch. Please look at your schedules and let me know by **Friday, April 16, 2010** if a meeting on May 4th would be agreeable. As soon as this is finalized, I will get a confirmation out to you. Thank you.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

Rebecca Witt

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Wednesday, April 14, 2010 2:57 PM
To: Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; Dan Brewer (E-mail); Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); bprather@farmersrecc.com; Wayne Davis; Jerry Carter; cperry@fme.coop; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; Carol Wright; Mark Keene; rodneychrisman@jacksonenergy.com; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Cheryl Thomas; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; Nicky Rapier; J. Edward Boone (E-mail); randyb@srelectric.com; debbiem; gay; denise@shelbyenergy.com; Allen Anderson; Stephen Johnson; Ruby Patterson; Amy Acton; Barry Myers (E-mail); John Patterson; abeard@tcrecc.com
Cc: jimadkins25@aol.com; Tony Campbell; Stacy Barker; David Eames; John Twitchell; Craig Johnson; Denver York; forward to davismart at FTB
Subject: RE: Next Meeting with Power System Engineering

Ladies and Gentlemen:

Let's try this again – I apologize for not realizing that there was a conflict for the Presidents/CEOs on May 4th. Given the nature of the discussions, I want to give every opportunity for the Presidents/CEOs to be present.

The only other date that appears to be available is Friday, May 7, 2010. Again, we would start at 10:00 a.m. and lunch would be provided.

Again, please look at your schedules and let me know by **Friday, April 16, 2010** if a meeting on May 7th would be agreeable. As soon as this is finalized, I will get a confirmation out to you.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

-----Original Message-----
From: Isaac Scott
Sent: Wednesday, April 14, 2010 2:03 PM
To: 'Bobby Sexton (E-mail)'; 'destepp@bigsandyrecc.com'; 'badavis@bigsandyrecc.com'; 'Dan Brewer (E-mail)'; 'Donald Smothers'; 'Cathryn W. Gibson'; 'Paul Embs (E-mail)'; 'David Duvall'; 'Holly Eades (E-mail)'; 'Ted Hampton (E-mail)'; 'Robert Tolliver (E-mail)'; 'bprather@farmersrecc.com'; 'Wayne Davis'; 'Jerry Carter'; 'cperry@fme.coop'; 'jhazelrigg@fme.coop'; 'Mary Beth Nance'; 'carol.fraley@graysonrecc.com'; 'Don Combs'; 'kim.bush@graysonrecc.com'; 'Jim Jacobus'; 'Vickie Lay (E-mail)'; 'Sheree Gilliam'; 'Don Schaefer'; 'Sharon Carson'; 'Carol Wright'; 'Mark Keene'; 'rodneychrisman@jacksonenergy.com'; 'Kerry Howard (E-mail)'; 'Sandra Bradley (E-mail)'; 'maudie@lvrecc.com'; 'Mickey Miller'; 'O. V. Sparks'; 'rryan@nolinrecc.com'; 'Cheryl Thomas'; 'Mark Stallons'; 'Rebecca Witt'; 'Mike Cobb'; 'larryh@srelectric.com'; 'Nicky Rapier'; 'J. Edward Boone (E-mail)'; 'randyb@srelectric.com'; 'debbiem'; 'gay'; 'denise@shelbyenergy.com'; 'Allen Anderson'; 'Stephen Johnson'; 'Ruby Patterson'; 'Amy Acton'; 'Barry Myers (E-mail)'; 'John Patterson'; 'abeard@tcrecc.com'
Cc: 'jimadkins25@aol.com'; Tony Campbell; Stacy Barker; David Eames; John Twitchell; Craig Johnson; Denver York; forward to davismart at FTB
Subject: Next Meeting with Power System Engineering

Ladies and Gentlemen:

The timetable Power System developed for the Rate Design Study calls for a Status Meeting on May 10th. Power System has asked if this meeting could be held the week before – sometime during the week of May 3rd. The purpose for this meeting is to discuss the wholesale cost of service study results with the Members. In addition, Power System believes that most if not all of the retail cost of service study results will be out to the Members by then and this meeting could allow for a review of general observations, answer questions, etc.

Looking at calendars and other schedules, it appears Tuesday, May 4, 2010 would be a good day for this meeting. We would start at 10:00 a.m. and will plan on having lunch. Please look at your schedules and let me know by **Friday, April 16, 2010** if a meeting on May 4th would be agreeable. As soon as this is finalized, I will get a confirmation out to you. Thank you.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

Rebecca Witt

From: Charlene Creager [charlene.creager@ekpc.coop]
Sent: Wednesday, April 14, 2010 8:14 AM
To: Rebecca Witt
Subject: FW: data request file
Attachments: EKP WORKSHEET MONTHLY REVENUE with numbers.xlsx; Owen RS-7.xlsx; New Billing Determinants for 2009_04142010.xls

Assumption is that this was forwarded on to PSE.

Becky,

fyi - I noticed the the formula was off for one month for your totals page. I went to create totals instead of averages on the number of billing determinants and if you look at the formula in the cell, it had the same cell reference for every month but one. I have attached my file but I have made totals for the number of customers instead of averages for our purpose. If you look at your worksheet, there are numbers in cell C45 but there is nothing in any month for that cell. I'm not sure I'm making any sense but I thought you might want to know.

Call if you have questions. 859-745-9759

Charlene
-----Original Message-----
From: Ann Wood
Sent: Tuesday, April 13, 2010 4:49 PM
To: Isaac Scott; Charlene Creager
Subject: FW: data request file

-----Original Message-----
From: Rebecca Witt [mailto:rwitt@owenelectric.com]
Sent: Tuesday, April 13, 2010 4:32 PM
To: lasliej@powersystem.org
Cc: Ann Wood
Subject: FW: data request file

Attached are files for use in the cost of service study.

Becky

From: Mike Cobb
Sent: Tuesday, April 13, 2010 4:31 PM
To: Rebecca Witt
Subject: RE: data request file

Becky,
See attached and forward to PSE for their study and maybe to Ann Wood for their too.
Mike

Michael L. Cobb
Owen Electric Cooperative, Inc.
8205 Hwy 127 N.
Owenton, Kentucky 40359
502/563-3533

Meter Replacement Costs

Meter Type No.	Phase	Units Metered	Time-of-Day [1]	Interval Recording [2]	PSE Model Cost	Owen Electric's Cost [3]
1	Single	kWh	NO	NO	$78	$0
2	Single	kWh	YES	NO	$117	$129
3	Three	kWh	NO	NO	$286	$0
4	Three	kWh and kW	NO	NO	$441	$0
5	Three	kWh, kW, PF/KVAR	NO	NO	$511	$0
6	Three	kWh, kW, PF/KVAR	YES	NO	$546	$487
7	Three	kWh, kW, PF/KVAR	YES	YES	$1,200	$737

[1] Capability to meter energy and/or demand data by defined periods.
[2] Capability to provide coincident demand information (i.e. hourly data).
[3] Please enter the replacement cost including installation for applicable meters used by the coop.

Meter Type by Rate Schedule

Instructions
Please select the meter type number from above that corresponds to meter functionality installed per the applicable rate schedule.

Rate Schedule	PSE Model Meter Type	Owen Electric's Meter Type
Schedule I - Farm and Residential - Rate 1	1	2
Schedule I - Small Commercial Single Phase - Rate 3	1	2
Schedule I - Small Commercial Three Phase - Rate 3	3	6
Schedule II - Large Commercial - Rate 4	5	6
Schedule XI - Large Industrial Rate LPB1 - Rate 9	6	7
Schedule XIII- Large Industrial Rate LPB2 - Rate 13	6	7
Schedule XIV - Large Industrial Rate LPB - Rate 12	6	7
Schedule 2-A-Large Power/Commercial Time-of-Day - Rate 20	6	7
Schedule ETS Off-Peak - Rate 10	2	2

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Jan 2009

Rate Code	Applicable Rate Schedule	No. of Consumers		Energy (kWh) Sales			Demand (kW) Sales		Revenues			
		Single Phase	Three Phase	Metered[1] (kWh)	Billed[2] (kWh)	Submetered (kWh)	Metered (kW)	Billed[3] (kW)	Base Rate[4] ($)	FCA ($)	Environmental Surcharge ($)	Total ($)
Rate 1	Schedule 1-Residential	53,745		82,291,735	82,291,735	n/a			6,498,763	1,105,346	550,347	8,154,456
Rate 3	Schedule 1-Small Commercial	2,302		4,349,048	4,349,048	n/a	8,798	8,798	341,187	58,493	29,035	428,715
Rate 4	*Schedule II-Large Commercial*		242	13,519,797	13,519,797	n/a	40,188	41,088	963,908	181,679	82,191	1,227,778
Rate 5	Primary Metered		3	80,400	80,400	n/a	2,839	2,839	56,455	10,806	4,823	72,084
Rate 6	Outdoor Light Only					n/a			132		1,514	1,646
Rate 9	Schedule XI- LPB1		10	5,830,608	5,830,608	n/a	13,388	13,388	371,852	78,363	32,280	482,495
Rate 10	ETS Off-Peak	8		6,994	6,994	n/a			316	91	29	436
Rate 12	Schedule XIV LPB		4	949,665	949,665	n/a	2,517	2,517	69,830	10,989	5,795	86,614
Rate 13	Scheudle XIII-LPB2		2	9,721,225	9,721,225	n/a	16,586	16,586	437,865	129,897	40,709	608,471
Rate 20	*Large Commercial Time-of-Day*		9	5,065,440	5,065,440	n/a			21,491	4,121		25,612
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,807		443,672	443,672							48,820
	Rate 2	1,478		84,145	84,145							11,738
	Rate 3	79		4,503	4,503							761
	Rate 4	7		399	399							79
	Rate 6	133		7,636	7,636							907
	Rate 7	51		2,907	2,907							431
	Rate 8	5		285	285							51
	Rate 21	2,607		99,211	99,211							23,300
	Rate 22	353		13,599	13,599							4,797
	Rate 31	7		280	280							85
	Rate 32	14		560	560							235
	Rate 33	7		498	498							100
	Rate 34	4		304	304							78
	Rate 35	15		2,310	2,310							319
	Rate 36	5		770	770							130
	Rate 41	12		448	448							127
	Rate 42	6		240	240							96
	Rate 43	18		1,494	1,494							257
	Rate 44	7		581	581							133
	Rate 45	61		9,394	9,394							1,134
	Rate 46	10		1,540	1,540							233
	Rate 51	290		11,600	11,600							2,861
	Rate 52	168		6,680	6,680							1,956
TOTAL		69,199		122,507,968			84,316	85,216	8,761,799	1,579,785		11,186,935

Notes
1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 *For use if kWh billed is different from kWh metered due to kWh minimums*
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Feb 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	No. of Consumers Three Phase	Energy (kWh) Sales Metered[1] (kWh)	Energy (kWh) Sales Billed[2] (kWh)	Energy (kWh) Sales Submetered (kWh)	Demand (kW) Sales Metered (kW)	Demand (kW) Sales Billed[3] (kW)	Revenues Base Rate[4] ($)	Revenues FCA ($)	Revenues Environmental Surcharge ($)	Revenues Total ($)
Rate 1	Schedule 1-Residential	53,884		82,244,810	82,244,810	n/a			6,495,654	415,069	518,492	7,429,215
Rate 3	Schedule 1-Small Commercial	2,267		4,456,989	4,456,989	n/a	8,921	8,921	349,217	22,498	27,988	399,703
Rate 4	Schedule II-Large Commercial		245	14,381,317	14,381,317	n/a	38,472	38,472	1,004,634	72,573	80,088	1,157,295
Rate 5	Primary Metered		4	1,121,400	1,121,400	n/a	4,507	4,507	82,052	5,663	6,517	94,232
Rate 6	Outdoor Light Only					n/a			132		1,498	1,630
Rate 9	Schedule XI- LPB1		10	5,534,733	5,534,733	n/a	11,835	11,835	327,286	27,950	26,394	381,630
Rate 10	ETS Off-Peak	8		6,129	6,129	n/a			277	30	23	330
Rate 12	Schedule XIV LPB		4	1,009,480	1,009,480	n/a	2,522	2,522	71,138	4,431	5,615	81,184
Rate 13	Scheudle XIII-LPB2		2	10,149,576	10,149,576	n/a	16,930	16,930	462,642	50,480	38,125	551,247
Rate 20	Large Commercial Time-of-Day		9	301,776	301,776	n/a			20,928	1,524		22,452
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,767		442,044	442,044							44,920
	Rate 2	1,472		83,800	83,800							10,985
	Rate 3	79		4,503	4,503							723
	Rate 4	7		399	399							76
	Rate 6	134		7,558	7,558							834
	Rate 7	51		2,907	2,907							406
	Rate 8	5		285	285							48
	Rate 21	2,616		101,097	101,097							22,898
	Rate 22	353		13,807	13,807							4,756
	Rate 31	7		280	280							82
	Rate 32	14		560	560							230
	Rate 33	7		581	581							112
	Rate 34	4		332	332							83
	Rate 35	15		2,310	2,310							299
	Rate 36	5		770	770							123
	Rate 41	11		432	432							119
	Rate 42	6		240	240							94
	Rate 43	19		1,577	1,577							257
	Rate 44	7		581	581							128
	Rate 45	61		9,394	9,394							1,055
	Rate 46	10		1,540	1,540							220
	Rate 51	300		11,600	11,600							2,764
	Rate 52	184		7,320	7,320							2,081
TOTAL		69,293		119,900,127			83,187	83,187	8,813,960	600,218		10,212,211

Notes

1. For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2. For use if kWh billed is different from kWh metered due to kWh minimums
3. kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4. Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Mar 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1] (kWh)	Energy (kWh) Sales: Billed[2] (kWh)	Energy (kWh) Sales: Submetered (kWh)	Demand (kW) Sales: Metered (kW)	Demand (kW) Sales: Billed[3] (kW)	Revenues: Base Rate[4] ($)	Revenues: FCA ($)	Revenues: Environmental Surcharge ($)	Revenues: Total ($)
Rate 1	Schedule 1-Residential	53,940		62,687,499	6,287,499	n/a			5,022,023	407,817	407,419	5,837,259
Rate 3	Schedule 1-Small Commercial	2,264		3,848,935	3,848,935	n/a	9,075	9,075	303,305	25,060	24,703	353,068
Rate 4	Schedule II-Large Commercial		258	13,094,070	13,094,070	n/a	38,192	38,192	929,967	85,229	75,277	1,090,473
Rate 5	Primary Metered		5	1,234,200	1,234,200	n/a	3,976	3,976	87,731	8,035	7,096	102,862
Rate 6	Outdoor Light Only					n/a			132		1,503	1,635
Rate 9	Schedule XI- LPB1		9	5,322,068	5,322,068	n/a	11,692	11,692	326,446	34,647	26,757	387,850
Rate 10	ETS Off-Peak	8		4,394	4,394	n/a			199	27	17	243
Rate 12	Schedule XIV LPB		4	1,000,869	1,000,869	n/a	2,496	2,496	71,662	5,656	5,729	83,047
Rate 13	Scheudle XIII-LPB2		2	9,131,538	9,131,538	n/a	16,325	16,325	416,016	58,727	35,179	509,922
Rate 20	Large Commercial Time-of-Day		9	258,408	258,408	n/a			17,970	1,682		19,652
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,755		441,812	441,812							45,583
	Rate 2	1,467		82,780	82,780							10,978
	Rate 3	78		4,446	4,446							721
	Rate 4	7		399	399							76
	Rate 6	130		7,410	7,410							829
	Rate 7	51		2,901	2,901							410
	Rate 8	5		285	285							49
	Rate 21	2,617		102,617	102,617							23,384
	Rate 22	355		13,697	13,697							4,738
	Rate 31	7		280	280							83
	Rate 32	14		560	560							231
	Rate 33	7		581	581							113
	Rate 34	4		332	332							83
	Rate 35	15		2,310	2,310							303
	Rate 36	5		770	770							124
	Rate 41	11		440	440							122
	Rate 42	6		240	240							95
	Rate 43	19		1,577	1,577							260
	Rate 44	7		581	581							129
	Rate 45	61		9,394	9,394							1,069
	Rate 46	14		1,540	1,540							262
	Rate 51	290		11,587	11,587							2,778
	Rate 52	184		7,320	7,320							2,091
TOTAL		69,321		97,275,840			81,756	81,756	7,175,451	626,880		8,480,522

Notes

1. For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2. For use if kWh billed is different from kWh metered due to kWh minimums
3. kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4. Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Apr 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1] (kWh)	Energy (kWh) Sales: Billed[2] (kWh)	Energy (kWh) Sales: Submetered (kWh)	Demand (kW) Sales: Metered (kW)	Demand (kW) Sales: Billed[3] (kW)	Revenues: Base Rate[4] ($)	Revenues: FCA ($)	Revenues: Environmental Surcharge ($)	Revenues: Total ($)
Rate 1	Schedule 1-Residential	53,946		50,360,899	50,360,899	n/a			4,220,783	459,325	344,655	5,024,763
Rate 3	Schedule I-Small Commercial	2,254		3,784,328	3,784,328	n/a	8,380	8,380	304,998	34,204	24,849	364,051
Rate 4	Schedule II-Large Commercial		255	12,680,464	12,680,464	n/a	40,612	40,612	940,007	115,754	76,597	1,132,358
Rate 5	Primary Metered		5	1,424,400	1,424,400	n/a	4,594	4,594	100,135	13,005	8,203	121,343
Rate 6	Outdoor Light Only					n/a			113		1,590	1,703
Rate 9	Schedule XI- LPB1		9	5,649,724	5,649,724	n/a	11,726	11,726	327,517	51,582	27,479	406,578
Rate 10	ETS Off-Peak	8		3,129	3,129	n/a			147	27	13	187
Rate 12	Schedule XIV LPB		4	989,045	989,045	n/a	2,477	2,477	71,034	7,825	5,717	84,576
Rate 13	Scheudle XIII-LPB2		2	8,996,511	8,996,511	n/a	16,182	16,182	411,096	81,221	35,693	528,010
Rate 20	Large Commercial Time-of-Day		9	249,456	249,456	n/a			17,765	2,278		20,043
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,721		440,513	440,513							49,376
	Rate 2	1,462		81,833	81,833							11,758
	Rate 3	79		4,503	4,503							788
	Rate 4	7		399	399							82
	Rate 6	130		7,410	7,410							900
	Rate 7	50		2,850	2,850							436
	Rate 8	5		285	285							53
	Rate 21	2,659		100,545	100,545							24,658
	Rate 22	351		13,712	13,712							5,083
	Rate 31	7		280	280							89
	Rate 32	14		560	560							247
	Rate 33	7		581	581							121
	Rate 34	4		332	332							89
	Rate 35	15		2,310	2,310							328
	Rate 36	5		770	770							134
	Rate 41	21		613	613							182
	Rate 42	6		240	240							101
	Rate 43	21		1,718	1,718							306
	Rate 44	8		611	611							146
	Rate 45	61		9,394	9,394							1,160
	Rate 46	14		1,540	1,540							320
	Rate 51	290		11,600	11,600							2,991
	Rate 52	184		7,320	7,320							2,244
TOTAL		69,329		84,827,875			83,971	83,971	6,393,595	765,221		7,785,204

Notes

1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for May 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	Three Phase	Energy (kWh) Sales Metered[1] (kWh)	Billed[2] (kWh)	Submetered (kWh)	Demand (kW) Sales Metered (kW)	Billed[3] (kW)	Revenues Base Rate[4] ($)	FCA ($)	Environmental Surcharge ($)	Total ($)
Rate 1	Schedule 1-Residential	54,076		45,778,062	45,778,062	n/a			3,995,924	465,941	331,666	4,793,531
Rate 3	Schedule 1-Small Commercial	2,251		3,616,036	3,616,036	n/a	8,600	8,600	302,874	36,452	25,134	364,460
Rate 4	Schedule II-Large Commercial		259	12,458,551	12,458,551	n/a	41,525	41,525	971,718	126,932	80,367	1,179,017
Rate 5	Primary Metered		5	1,616,400	1,616,400	n/a	5,188	5,188	118,193	16,471	9,844	144,508
Rate 6	Outdoor Light Only					n/a			132		1,630	1,762
Rate 9	Schedule XI- LPB1		9	5,158,093	5,158,093	n/a	11,991	11,991	340,336	52,561	28,721	421,618
Rate 10	ETS Off-Peak	8		797	797	n/a			38	6	3	47
Rate 12	Schedule XIV LPB		4	969,945	969,945	n/a	2,557	2,557	76,059	8,539	6,184	90,782
Rate 13	Scheudle XIII-LPB2		2	8,286,492	8,286,492	n/a	14,400	14,400	428,181	81,668	37,270	547,119
Rate 20	Large Commercial Time-of-Day		9	261,216	261,216	n/a			20,060	2,662		22,722
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,694		437,945	437,945							49,556
	Rate 2	1,461		83,056	83,056							12,007
	Rate 3	79		4,503	4,503							793
	Rate 4	7		399	399							83
	Rate 6	130		7,410	7,410							907
	Rate 7	50		2,850	2,850							439
	Rate 8	5		285	285							53
	Rate 21	2,709		105,241	105,241							25,860
	Rate 22	366		14,907	14,907							5,514
	Rate 31	12		480	480							152
	Rate 32	14		560	560							248
	Rate 33	7		581	581							122
	Rate 34	4		332	332							90
	Rate 35	16		2,346	2,346							335
	Rate 36	5		770	770							135
	Rate 41	24		924	924							275
	Rate 42	6		240	240							101
	Rate 43	22		1,826	1,826							327
	Rate 44	8		664	664							159
	Rate 45	62		9,481	9,481							1,181
	Rate 46	16		1,715	1,715							349
	Rate 51	290		11,600	11,600							3,004
	Rate 52	184		7,320	7,320							2,252
TOTAL		69,506		78,841,027			84,261	84,261	6,253,515	791,232		7,669,508

Notes
1. For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2. For use if kWh billed is different from kWh metered due to kWh minimums
3. kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4. Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request

Unit Sales and Revenue Data by Month by Rate Class
Data for Jun 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1] (kWh)	Energy (kWh) Sales: Billed[2] (kWh)	Energy (kWh) Sales: Submetered (kWh)	Demand (kW) Sales: Metered (kW)	Demand (kW) Sales: Billed[3] (kW)	Revenues: Base Rate[4] ($)	Revenues: FCA ($)	Revenues: Environmental Surcharge ($)	Revenues: Total ($)
Rate 1	Schedule 1-Residential	54,049		50,300,883	50,300,883	n/a			4,358,961	331,178	371,525	5,061,664
Rate 3	Schedule 1-Small Commercial	2,279		3,542,718	3,542,718	n/a	9,241	9,241	298,739	23,351	25,553	347,643
Rate 4	Schedule II-Large Commercial		240	12,455,699	12,455,699	n/a	42,478	42,478	976,214	82,070	82,604	1,140,888
Rate 5	Primary Metered		5	1,692,600	1,692,600	n/a	5,681	5,681	125,083	11,154	10,627	146,864
Rate 6	Outdoor Light Only					n/a			122		1,702	1,824
Rate 9	Schedule XI- LPB1		9	5,357,970	5,357,970	n/a	11,963	11,963	337,484	35,309	29,078	401,871
Rate 10	ETS Off-Peak	8		208	208	n/a			10	1	1	12
Rate 12	Schedule XIV LPB		4	981,784	981,784	n/a	2,735	2,735	76,886	5,600	6,434	88,920
Rate 13	Scheudle XIII-LPB2		2	7,564,046	7,564,046	n/a	13,550	13,550	420,096	49,847	36,656	506,599
Rate 20	Large Commercial Time-of-Day		9	303,240	303,240	n/a			23,789	1,998		25,787
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,662		434,400	434,400							47,566
	Rate 2	1,451		82,544	82,544							11,631
	Rate 3	79		4,503	4,503							777
	Rate 4	7		399	399							81
	Rate 6	130		7,410	7,410							880
	Rate 7	50		2,850	2,850							428
	Rate 8	5		285	285							52
	Rate 21	2,739		105,776	105,776							25,634
	Rate 22	364		14,962	14,962							5,491
	Rate 31	13		520	520							163
	Rate 32	14		560	560							246
	Rate 33	7		581	581							120
	Rate 34	4		332	332							89
	Rate 35	15		2,310	2,310							322
	Rate 36	5		770	770							132
	Rate 41	23		920	920							271
	Rate 42	6		240	240							101
	Rate 43	22		1,826	1,826							320
	Rate 44	8		664	664							156
	Rate 45	62		9,548	9,548							1,155
	Rate 46	16		1,848	1,848							363
	Rate 51	290		11,600	11,600							2,962
	Rate 52	185		7,320	7,320							2,225
TOTAL		69,493		82,891,316			85,648	85,648	6,617,384	540,508		7,823,237

Notes

1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Jul 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	Three Phase	Energy (kWh) Sales Metered[1]	Billed[2]	Submetered	Demand (kW) Sales Metered	Billed[3]	Revenues Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
Rate 1	Schedule 1-Residential	54,260		62,025,037	62,025,037	n/a			5,581,305	215,027	438,869	6,235,201
Rate 3	Schedule 1-Small Commercial	2,305		4,025,574	4,025,574	n/a	9,496	9,496	353,807	13,990	27,914	395,711
Rate 4	Schedule II-Large Commercial		242	13,161,966	13,161,966	n/a	43,530	43,530	1,028,279	45,559	80,161	1,153,999
Rate 5	Primary Metered		6	2,112,000	2,112,000	n/a	6,062	6,062	151,108	7,329	11,819	170,256
Rate 6	Outdoor Light Only					n/a			132		1,987	2,119
Rate 9	Schedule XI- LPB1		9	5,562,509	5,562,509	n/a	12,194	12,194	356,452	19,302	28,031	403,785
Rate 10	ETS Off-Peak	8				n/a						
Rate 12	Schedule XIV LPB		4	1,062,339	1,062,339	n/a	2,838	2,838	78,573	3,228	6,102	87,903
Rate 13	Scheudle XIII-LPB2		2	8,696,971	8,696,971	n/a	15,251	15,251	409,055	30,178	32,767	472,000
Rate 20	Large Commercial Time-of-Day		9	386,088	386,088	n/a			30,396	1,340	8	31,744
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,634		433,816	433,816							61,671
	Rate 2	1,451		82,351	82,351							14,219
	Rate 3	79		4,486	4,486							912
	Rate 4	7		399	399							93
	Rate 6	131		8,835	8,835							1,306
	Rate 7	50		2,850	2,850							526
	Rate 8	5		285	285							61
	Rate 21	2,800		109,179	109,179							26,799
	Rate 22	364		13,884	13,884							5,050
	Rate 31	13		520	520							166
	Rate 32	14		560	560							244
	Rate 33	7		581	581							121
	Rate 34	4		332	332							88
	Rate 35	15		2,310	2,310							323
	Rate 36	5		770	770							131
	Rate 41	23		920	920							275
	Rate 42	6		240	240							100
	Rate 43	22		1,826	1,826							322
	Rate 44	8		664	664							155
	Rate 45	62		9,548	9,548							1,155
	Rate 46	16		1,848	1,848							359
	Rate 51	296		11,696	11,696							3,687
	Rate 52	183		7,280	7,280							2,737
TOTAL		69,768		97,727,664			89,371	89,371	7,989,107	335,953		9,073,218

Notes

1 *For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period*
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Aug 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1] (kWh)	Energy (kWh) Sales: Billed[2] (kWh)	Energy (kWh) Sales: Submetered (kWh)	Demand (kW) Sales: Metered (kW)	Demand (kW) Sales: Billed[3] (kW)	Revenues: Base Rate[4] ($)	Revenues: FCA ($)	Revenues: Environmental Surcharge ($)	Revenues: Total ($)
Rate 1	Schedule 1-Residential	54,205		62,459,556	62,459,556	n/a			5,907,975	-21,839	465,517	6,351,653
Rate 3	Schedule 1-Small Commercial	2,293		4,202,306	4,202,306	n/a	9,739	9,739	383,845	-1,471	30,309	412,683
Rate 4	Schedule II-Large Commercial		244	13,812,569	13,812,569	n/a	42,278	42,278	1,089,835	-4,834	84,642	1,169,643
Rate 5	Primary Metered		6	2,280,000	2,280,000	n/a	6,162	6,162	164,583	-798	12,759	176,544
Rate 6	Outdoor Light Only					n/a			121		2,157	2,278
Rate 9	Schedule XI- LPB1		9	5,671,114	5,671,114	n/a	12,155	12,155	356,415	-1,984	27,610	382,041
Rate 10	ETS Off-Peak	8				n/a						
Rate 12	Schedule XIV LPB		4	1,049,556	1,049,556	n/a	2,667	2,667	77,218	-321	5,990	82,887
Rate 13	Scheudle XIII-LPB2		3	9,579,768	9,579,768	n/a	15,781	15,781	444,830	-3,353	34,391	475,868
Rate 20	Large Commercial Time-of-Day		9	496,656	496,656	n/a			39,612	-174	3,072	42,510
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,604		431,538	431,538							63,970
	Rate 2	1,440		83,175	83,175							14,807
	Rate 3	80		4,477	4,477							937
	Rate 4	7		399	399							96
	Rate 6	132		7,494	7,494							1,199
	Rate 7	50		2,850	2,850							543
	Rate 8	5		285	285							63
	Rate 21	2,832		109,215	109,215							27,628
	Rate 22	366		14,221	14,221							5,275
	Rate 31	13		520	520							170
	Rate 32	14		560	560							248
	Rate 33	7		581	581							125
	Rate 34	4		332	332							90
	Rate 35	15		2,310	2,310							339
	Rate 36	5		770	770							136
	Rate 41	23		920	920							281
	Rate 42	6		240	240							102
	Rate 43	22		1,826	1,826							335
	Rate 44	8		664	664							159
	Rate 45	62		9,548	9,548							1,220
	Rate 46	16		1,848	1,848							372
	Rate 51	300		12,000	12,000							3,866
	Rate 52	183		7,280	7,280							2,787
TOTAL		69,700		100,244,578			88,782	88,782	8,464,434	-34,774		9,220,855

Notes

1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Sep 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	Three Phase	Energy (kWh) Sales Metered[1] (kWh)	Billed[2] (kWh)	Submetered (kWh)	Demand (kW) Sales Metered (kW)	Billed[3] (kW)	Revenues Base Rate[4] ($)	FCA ($)	Environmental Surcharge ($)	Total ($)
Rate 1	Schedule 1-Residential	54,190		57,812,426	57,812,426	n/a			5,855,689	59,514	469,013	6,384,216
Rate 3	Schedule 1-Small Commercial	2,318		3,988,486	3,988,486	n/a	9,308	9,308	393,538	4,108	31,572	429,218
Rate 4	Schedule II-Large Commercial		236	13,721,856	13,721,856	n/a	43,899	43,899	1,209,832	14,131	95,661	1,319,624
Rate 5	Primary Metered		6	2,448,000	2,448,000	n/a	6,554	6,554	197,209	2,521	15,599	215,329
Rate 6	Outdoor Light Only					n/a			132		2,166	2,298
Rate 9	Schedule XI- LPB1		9	6,040,725	6,040,725	n/a	12,694	12,694	440,626	6,222	34,899	481,747
Rate 10	ETS Off-Peak	8				n/a						
Rate 12	Schedule XIV LPB		7	1,092,845	1,092,845	n/a	2,797	2,797	95,879	990	7,565	104,434
Rate 13	Scheudle XIII-LPB2		2	10,097,125	10,097,125	n/a	16,168	16,168	572,517	10,400	45,526	628,443
Rate 20	Large Commercial Time-of-Day		10	277,104	277,104	n/a			25,184	285	1,989	27,458
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,550		428,023	428,023							63,823
	Rate 2	1,428		81,033	81,033							14,579
	Rate 3	78		4,414	4,414							929
	Rate 4	7		399	399							96
	Rate 6	132		7,429	7,429							1,197
	Rate 7	50		2,850	2,850							546
	Rate 8	5		285	285							63
	Rate 21	2,872		110,418	110,418							28,163
	Rate 22	381		14,686	14,686							5,465
	Rate 31	13		520	520							170
	Rate 32	14		560	560							249
	Rate 33	7		581	581							126
	Rate 34	4		332	332							91
	Rate 35	15		2,310	2,310							342
	Rate 36	5		770	770							137
	Rate 41	23		920	920							282
	Rate 42	7		185	185							92
	Rate 43	22		1,798	1,798							332
	Rate 44	7		581	581							140
	Rate 45	62		9,548	9,548							1,233
	Rate 46	16		1,848	1,848							374
	Rate 51	300		12,000	12,000							3,882
	Rate 52	183		7,280	7,280							2,797
TOTAL		69,697		96,167,337			91,420	91,420	8,790,606	98,171		9,717,875

Notes

1. For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2. For use if kWh billed is different from kWh metered due to kWh minimums
3. kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4. Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request

Unit Sales and Revenue Data by Month by Rate Class
Data for Oct 2009

		No. of Consumers		Energy (kWh) Sales			Demand (kW) Sales		Revenues			
Rate Code	Applicable Rate Schedule	Single Phase	Three Phase	Metered[1] (kWh)	Billed[2] (kWh)	Submetered (kWh)	Metered (kW)	Billed[3] (kW)	Base Rate[4] ($)	FCA ($)	Environmental Surcharge ($)	Total ($)
Rate 1	Schedule 1-Residential	54,231		47,108,214	47,108,214	n/a			4,879,009	-492,701	372,366	4,758,674
Rate 3	Schedule 1-Small Commercial	240		3,700,418	3,700,418	n/a	9,145	9,145	367,630	-38,732	27,916	356,814
Rate 4	Schedule II-Large Commercial		239	13,851,659	13,851,659	n/a	42,774	42,774	1,208,077	-145,006	88,623	1,151,694
Rate 5	Primary Metered		7	2,571,600	2,571,600	n/a	6,911	6,911	207,219	-26,925	15,036	195,330
Rate 6	Outdoor Light Only					n/a			132		2,191	2,323
Rate 9	Schedule XI- LPB1		9	5,658,847	5,658,847	n/a	12,210	12,210	430,664	-59,248	30,939	402,355
Rate 10	ETS Off-Peak	9		829	829	n/a			45	-9	3	39
Rate 12	Schedule XIV LPB		3	632,306	632,306	n/a	1,848	1,848	64,452	-5,238	4,933	64,147
Rate 13	Scheudle XIII-LPB2		2	9,614,292	9,614,292	n/a	16,012	16,012	555,775	-100,662	37,911	493,024
Rate 20	Large Commercial Time-of-Day		10	244,288	244,288	n/a			22,377	-2,558	1,651	21,470
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,498		424,066	424,066							58,552
	Rate 2	1,414		80,446	80,446							13,550
	Rate 3	75		4,275	4,275							851
	Rate 4	7		399	399							92
	Rate 6	131		7,395	7,395							1,107
	Rate 7	50		2,820	2,820							508
	Rate 8	5		285	285							60
	Rate 21	2,901		112,298	112,298							27,240
	Rate 22	390		14,160	14,160							5,122
	Rate 31	14		560	560							177
	Rate 32	14		560	560							242
	Rate 33	7		581	581							119
	Rate 34	4		332	332							87
	Rate 35	15		2,310	2,310							315
	Rate 36	5		770	770							129
	Rate 41	28		1,645	1,645							491
	Rate 42	6		240	240							99
	Rate 43	20		1,660	1,660							288
	Rate 44	7		581	581							134
	Rate 45	61		9,394	9,394							1,105
	Rate 46	17		2,002	2,002							376
	Rate 51	321		12,605	12,605							3,933
	Rate 52	183		7,016	7,016							2,615
TOTAL		67,653		84,068,853		0	88,900	88,900	7,735,380	-871,079		7,563,062

Notes

1. For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period.
2. For use if kWh billed is different from kWh metered due to kWh minimums.
3. kW Demand billed should include adjustments for contract minimums, ratchets and power factor.
4. Outdoor Lighting revenues should be shown as separate rate class.

PSE Rate Study Revenue Data Request

Unit Sales and Revenue Data by Month by Rate Class
Data for Nov 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1] (kWh)	Energy (kWh) Sales: Billed[2] (kWh)	Energy (kWh) Sales: Submetered (kWh)	Demand (kW) Sales: Metered (kW)	Demand (kW) Sales: Billed[3] (kW)	Revenues: Base Rate[4] ($)	Revenues: FCA ($)	Revenues: Environmental Surcharge ($)	Revenues: Total ($)
Rate 1	Schedule 1-Residential	54,364		46,171,660	46,171,660	n/a			4,794,104	-360,409	292,801	4,726,496
Rate 3	Schedule 1-Small Commercial	2,332		3,400,980	3,400,980	n/a	8,664	8,664	340,171	-26,597	20,727	334,301
Rate 4	Schedule II-Large Commercial		235	12,221,506	12,221,506	n/a	38,846	38,846	1,076,980	-95,556	63,651	1,045,075
Rate 5	Primary Metered		8	2,264,400	2,264,400	n/a	6,742	6,742	186,284	-17,708	10,928	179,504
Rate 6	Outdoor Light Only					n/a			81		1,720	1,801
Rate 9	Schedule XI- LPB1		9	5,631,368	5,631,368	n/a	11,062	11,062	419,653	-44,037	24,340	399,956
Rate 10	ETS Off-Peak	8		2,365	2,365	n/a			130	-19	7	118
Rate 12	Schedule XIV LPB		3	594,760	594,760	n/a	1,527	1,527	54,899	-3,619	3,323	54,603
Rate 13	Scheudle XIII-LPB2		2	9,158,786	9,158,786	n/a	15,874	15,874	532,130	-71,622	29,841	490,349
Rate 20	Large Commercial Time-of-Day		10	256,552	256,552	n/a			21,180	-2,006	1,242	20,416
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,457		421,456	421,456							57,399
	Rate 2	1,414		80,352	80,352							13,746
	Rate 3	75		4,234	4,234							853
	Rate 4	7		399	399							93
	Rate 6	129		7,259	7,259							1,106
	Rate 7	48		2,736	2,736							-209
	Rate 8	5		285	285							61
	Rate 21	2,939		113,380	113,380							27,836
	Rate 22	394		15,238	15,238							5,537
	Rate 31	15		597	597							190
	Rate 32	14		560	560							244
	Rate 33	7		581	581							121
	Rate 34	4		332	332							88
	Rate 35	15		2,310	2,310							321
	Rate 36	5		770	770							131
	Rate 41	28		1,120	1,120							334
	Rate 42	6		240	240							100
	Rate 43	18		1,494	1,494							263
	Rate 44	7		581	581							135
	Rate 45	62		9,481	9,481							1,141
	Rate 46	17		2,002	2,002							381
	Rate 51	313		12,520	12,520							3,940
	Rate 52	174		6,920	6,920							2,598
TOTAL		69,857		80,387,224			82,715	82,715	7,425,612	-621,573		7,369,028

Notes

1 *For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period.*
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request

Unit Sales and Revenue Data by Month by Rate Class
Data for Dec 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	No. of Consumers Three Phase	Energy (kWh) Sales Metered[1] (kWh)	Energy (kWh) Sales Billed[2] (kWh)	Energy (kWh) Sales Submetered (kWh)	Demand (kW) Sales Metered (kW)	Demand (kW) Sales Billed[3] (kW)	Revenues Base Rate[4] ($)	Revenues FCA ($)	Revenues Environmental Surcharge ($)	Revenues Total ($)
Rate 1	Schedule 1-Residential	54,018		61,208,280	61,208,280	n/a	n/a	n/a	6,165,834	-858,646	60,354	5,367,542
Rate 3	Schedule 1-Small Commercial	2,346		3,736,228	3,736,228		9,158	9,158	370,821	-52,460	3,629	321,990
Rate 4	Schedule II-Large Commercial		237	12,489,310	12,489,310		39,699	39,699	1,100,518	-175,322	10,384	935,580
Rate 5	Primary Metered		8	1,223,400	1,223,400		4,451	4,451	105,233	-17,177	987	89,043
Rate 6	Outdoor Light Only								132		288	420
Rate 9	Schedule XI- LPB1		10	6,177,210	6,177,210		13,098	13,098	460,297	-86,728	21,554	395,123
Rate 10	ETS Off-Peak	8		2,796	2,796				153	-39	1	115
Rate 12/16	Schedule XIV LPB		3	550,781	550,781		1,546	1,546	56,859	-5,880	1,254	52,233
Rate 13	Scheudle XIII-LPB2		13	8,937,506	8,937,506		15,826	15,826	522,244	-125,483	27,819	424,580
Rate 20	Large Commercial Time-of-Day		10	292,296	292,296				24,989	-4,104	234	21,119
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,403		420,343	420,343							56,500
	Rate 2	1,406		79,970	79,970							13,188
	Rate 3	74		5,612	5,612							1,065
	Rate 4	7		399	399							90
	Rate 6	125		7,125	7,125							1,041
	Rate 7	48		2,736	2,736							483
	Rate 8	5		285	285							59
	Rate 21	2,939		116,046	116,046							27,734
	Rate 22	395		15,437	15,437							5,513
	Rate 31	15		600	600							187
	Rate 32	14		560	560							241
	Rate 33	7		581	581							117
	Rate 34	4		332	332							86
	Rate 35	15		2,310	2,310							307
	Rate 36	5		770	770							126
	Rate 41	29		1,160	1,160							339
	Rate 42	6		240	240							98
	Rate 43	18		1,494	1,494							253
	Rate 44	7		581	581							131
	Rate 45	62		9,471	9,471							1,080
	Rate 46	17		2,002	2,002							369
	Rate 51	313		12,520	12,520							3,862
	Rate 52	174		6,920	6,920							2,555
TOTAL		69,460		95,305,301			83,778	83,778	8,807,080	-1,325,839		7,723,169

Notes
1. For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2. For use if kWh billed is different from kWh metered due to kWh minimums
3. kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4. Outdoor Lighting revenues should be shown as separate rate class

Need Totals, not avg

Rate Code	Applicable Rate Schedule	No. of Consumers		Energy (kWh) Sales			Demand (kW) Sales		Revenues			
		Single Phase	Three Phase	Metered[1]	Billed[2]	Submetered	Metered	Billed[3]	Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
Rate 1	Schedule 1-Residen	648,908		710,449,061	654,049,061				63,776,024	1,725,622		70,124,670
Rate 3	Schedule 1-Small C	25,451		46,652,046	46,652,046		9,496	108,525	4,110,132	98,896		4,508,357
Rate 4	Schedule II-Large C		2,932	157,848,764	157,848,764		43,530	493,393	12,499,969	303,209		13,703,424
Rate 5	Primary Metered		68	20,068,800	20,068,800		6,062	63,667	1,581,285	12,376		1,707,899
Rate 6	Outdoor Light Only								1,493			21,439
Rate 9	Schedule XI- LPB1		111	67,594,969	67,594,969		12,194	146,008	4,495,028	113,939		4,947,049
Rate 10	ETS Off-Peak	97		27,641	27,641				1,315	115		1,527
Rate 12	Schedule XIV LPB		48	10,883,375	10,883,375		2,838	28,527	864,489	32,200		961,330
Rate 13	Scheudle XIII-LPB2		36	109,933,836	109,933,836		15,251	188,885	5,612,447	191,298		6,235,632
Rate 20	Large Commercial 1		112	8,392,520	8,392,520				285,741	7,048		300,985
		674,456	3,307	1,131,851,012	1,075,451,012		89,371	1,029,005	93,227,923	2,484,703		102,512,312
	YARD LIGHTS:											
	Rate 1	91,552		5,199,628	5,199,628							647,736
	Rate 2	17,344		985,485	985,485							153,186
	Rate 3	934		54,459	54,459							10,110
	Rate 4	84		4,788	4,788							1,037
	Rate 6	1,567		90,371	90,371							12,213
	Rate 7	599		34,107	34,107							4,947
	Rate 8	60		3,420	3,420							673
	Rate 21	33,230		1,285,023	1,285,023							311,134
	Rate 22	4,432		172,310	172,310							62,341
	Rate 31	136		5,437	5,437							1,714
	Rate 32	168		6,720	6,720							2,905
	Rate 33	84		6,889	6,889							1,417
	Rate 34	48		3,956	3,956							1,042
	Rate 35	181		27,756	27,756							3,853
	Rate 36	60		9,240	9,240							1,568
	Rate 41	256		10,462	10,462							3,098
	Rate 42	73		2,825	2,825							1,179
	Rate 43	243		20,116	20,116							3,520
	Rate 44	89		7,334	7,334							1,705
	Rate 45	739		113,595	113,595							13,688
	Rate 46	179		21,273	21,273							3,978
	Rate 51	3,593		142,928	142,928							40,530
	Rate 52	2,169		85,976	85,976							28,938
TOTAL		157,820		8,294,098	8,294,098		89,371	1,029,005	93,227,923	2,484,703		103,824,824

Notes

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2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class
4 Outdoor Lighting revenues should be shown as separate rate class

√ **Rebecca Witt**

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Monday, April 19, 2010 10:17 AM
To: Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; Dan Brewer (E-mail); Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); bprather@farmersrecc.com; Wayne Davis; Jerry Carter; cperry@fme.coop; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; Carol Wright; Mark Keene; rodneychrisman@jacksonenergy.com; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Cheryl Thomas; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; Nicky Rapier; J. Edward Boone (E-mail); randyb@srelectric.com; debbiem; gay; denise@shelbyenergy.com; Allen Anderson; Stephen Johnson; Ruby Patterson; Amy Acton; Barry Myers (E-mail); John Patterson; abeard@tcrecc.com
Cc: jimadkins25@aol.com; Tony Campbell; Stacy Barker; David Eames; John Twitchell; Craig Johnson; Denver York; forward to davismart at FTB
Subject: Confirmation: Next Meeting with Power System Engineering

Ladies and Gentlemen:

You are invited to a status meeting with Power System Engineering on May 7, 2010. The meeting will be held in the Board Room of EKPC's headquarters and begin at 10:00 a.m. We will likely go into the afternoon, so lunch will be provided. The purpose for this meeting is to discuss the wholesale cost of service study results with the Members. In addition, Power System believes that most if not all of the retail cost of service study results will be out to the Members by then and this meeting could allow for a review of general observations, answer questions, etc.

In order to properly plan for sufficient copies of materials and lunch, please let me know by the close of business on **May 3, 2010** how many would be attending from your cooperative. Several of you have already provided this information and <u>you do not need to respond again unless your numbers change.</u> We are looking forward to seeing you all on May 7th. Thank you.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

Rebecca Witt

From: Mike Cobb
Sent: Tuesday, April 27, 2010 2:42 PM
To: Rebecca Witt
Subject: RE: Flow-through Rates
Attachments: EKP Rate Case Data.xls; EKP WORKSHEET MONTHLY REVENUE with numbers.xlsx

Please send to Charlene & Ann (EKPC) and Kathy Cobb (PSE).

Michael L. Cobb
Owen Electric Cooperative, Inc.
8205 Hwy 127 N.
Owenton, Kentucky 40359
502/563-3533

From: Rebecca Witt
Sent: Monday, April 26, 2010 5:25 PM
To: Mike Cobb
Subject: RE: Flow-through Rates

That works for me. Can we meet at 2:00 or 2:30?

From: Mike Cobb
Sent: Monday, April 26, 2010 4:51 PM
To: Rebecca Witt; Judy Osborne
Subject: RE: Flow-through Rates

We just sent the tariff sheets this afternoon, so we can check that off the list. But it looks like Charlene has a list of other stuff. Let's meet tomorrow, if possible to see what else we can supply.

Michael L. Cobb
Owen Electric Cooperative, Inc.
8205 Hwy 127 N.
Owenton, Kentucky 40359
502/563-3533

From: Rebecca Witt
Sent: Monday, April 26, 2010 9:39 AM
To: Mike Cobb
Subject: FW: Flow-through Rates

Mike,

See Charlene's request below. I thought I had forwarded this already, but couldn't find where that was done. If you already have this, just disregard. We can get together and discuss, if needed.

Thanks,
Becky

From: Charlene Creager [mailto:charlene.creager@ekpc.coop]
Sent: Friday, April 23, 2010 5:27 PM

To: Rebecca Witt
Cc: Ann Wood
Subject: Flow-through Rates

Becky,

I'm working on your billing analysis for the flow-through tariff changes resulting from EKPC's rate case.

You sent billing determinants but I still need a few things:

Current tariff sheets in electronic format that we can update
Billing determinants for all lighting rates - number of bills, current rates, kWh per lamp, etc.
For any B rates, I need the kW for firm demand and excess demand split out
For Rate 20, Large Commercial Time of day - Are these Owen's rate 2-A? I need the on-peak and off-peak energy numbers.

I will be on vacation next week but I will be checking my e-mail. Let me know if you have questions or you can talk with Ann Wood.

When I return, I will need to finish these analyses right away. Once the calculations are done, we will send to you and Mark Stallons for review before we submit on Owen's behalf. You'll be hearing more from us..

Hope you have a great weekend.

Charlene Creager
Analyst, Regulatory Services
East Kentucky Power Cooperative
Phone 859-745-9759
e-mail: charlene.creager@ekpc.coop

B Rate Billing KW Demand Splits

	January			February			March			April			May			June	
	Actual	Contract	Exess	Actual	Contract	Exess	Actual	Contract	Exess	Actual	Contract	Exess	Actual	Contract	Exess	Actual	Contract
Air Liquide	8233	8500	0	8124	8500	0	8876	8500	376	8475	8500	0	8597	8500	97	8283	8500
CW.Zumbiel	1456	1550	0	1486	1550	0	1400	1425	0	1498	1425	73	1573	1425	148	1549	1475
Cascades	836	1000	0	789	1000	0	871	1000	0	855	1000	0	877	1000	0	990	1000
Cengage	2212	2000	212	2230	2000	230	2166	2000	166	2147	2000	147	1886	2000	0	1975	2000
Duro Bag	1259	1524	0	1276	1524	0	1230	1524	0	1287	1524	0	1382	1524	0	1351	1524
Mauser	887	800	87	869	800	69	872	800	72	896	800	96	879	800	79	880	800
Messier- Bugatti	8700	7700	1000	8202	8200	2	7304	8200	0	5922	8200	0	4950	7500	0	6969	6800
Mississippi Lime	1701	1600	101	1701	1700	1	1721	1700	21	1744	1700	44	1779	1700	79	1545	1700
SKF	456	500	0	464	500	0	449	500	0	503	500	3	578	500	78	575	500
Steel Technologies	1345	1100	245	1240	1100	140	1244	1100	144	1255	1100	155	1169	1100	69	1181	1100
Toyota Lab	597	700	0	605	700	0	606	700	0	609	700	0	717	700	17	818	700
Toyota Headquarters	886	1200	0	885	1200	0	1061	1200	0	1209	1200	9	1203	1200	3	1374	1200
Toyota Whse	1223	1200	23	1179	1200	0	1075	1200	0	1120	1100	20	1221	1100	121	1291	1100
U.S. Playing Cards																	
Xpedx	582	600	0	559	600	0	550	600	0	549	600	0	561	600	0	565	600
ZF Boge	918	1050	0	904	1200	0	956	1050	0	878	1050	0	871	1050	0	939	1050

	July			August			September			October			November			December		
Exess	Actual	Contract	Exess	Actual	Contract	Exess	Actual	Contract	Exess	Actual	Contract	Exess	Actual	Contract	Exess	Actual	Contract	Exess
0	8457	8500	0	8606	8500	106	7907	8500	0	8204	8500	0	8048	8500	0	7947	8500	0
74	1561	1475	86	1617	1475	142	1620	1425	195	1489	1425	64	1394	1425	0	1509	1425	84
0	986	1000	0	982	1000	0	950	1000	0	885	1000	0	877	1000	0	799	1000	0
0	1922	2000	0	1953	2000	0	1811	2000	0	1571	2000	0	1528	2000	0	1682	1700	0
0	1305	1524	0	1426	1524	0	1437	1524	0	1498	1524	0	1535	1524	11	1414	1524	0
80	874	800	74	861	800	61												
169	7323	7500	0	7560	7500	60	8100	8000	100	7670	8100	0	7775	8100	0	7918	8100	0
0	1648	1700	0	1679	1700	0	1657	1700	0	1282	1700	0	1391	1000	391	1347	1000	347
75	568	500	68	581	500	81	561	500	61	476	500	0	442	500	0	442	500	0
81	1181	1100	81	1248	1100	148	1216	1100	116	1228	1100	128	1211	1100	111	1272	1100	172
118	682	700	0	766	900	0	680	900	0	546	550	0	559	550	9	539	550	0
174	1230	1200	30	1401	1400	1	1182	1400	0	1015	1000	15	892	1000	0	806	1000	0
191	1277	1100	177	1324	1100	224	1208	1100	108	1003	1100	0	1094	1100	0	1180	1100	80
													2104	2200	0	2048	2100	0
0	543	600	0	588	600	0	607	600	7	505	600	0	544	600	0	529	600	0
0	1048	1050	0	1063	1100	0	1131	1050	81	1092	1050	42	1070	1250	0	1162	1250	0

Time of Use Billing

Account	Name	January ON PEAK KW	January OFF PEAK KW	February ON PEAK KW	February OFF PEAK KW	March ON PEAK KW	March OFF PEAK KW	April ON PEAK KW	April OFF PEAK KW	May ON PEAK KW	May OFF PEAK KW	June ON PEAK KW	June OFF PEAK KW	July ON PEAK KW	July OFF PEAK KW
1544-06	Boone County Fiscal Ct	0	288	0	0	0	0	0	0	0	0	288	1200	912	2208
1544-13	Boone County Fiscal Ct	672	0	0	0	0	0	0	0	672	0	3744	0	1632	0
1544-14	Boone County Fiscal Ct	0	0	0	0	0	0	0	0	96	0	3360	96	4512	0
1544-16	Boone County Fiscal Ct	1536	0	0	0	0	0	0	0	720	0	3888	0	4128	48
1544-17	Boone County Fiscal Ct	576	0	0	48	0	0	0	0	0	0	3504	0	2880	0
74356-04	KY Speedway	98400	134400	114000	157200	85200	120000	73200	106800	82800	102000	124800	106800	177600	140400
74356-14	KY Speedway	1200	1200	1200	2400	2400	1200	1200	2400	0	0	0	1200	2400	1200
88184-03	Nugent Sand Co.	31200	31200	9000	11400	18600	26400	36000	26400	45600	27600	28800	24600	25800	21600
8093-02	Garry Ennis	4416	1536	4608	1920	3264	1344	2496	960	768	960	192	768	192	576
106814-01	Kenton Lakes Sportsplex														

August		September		October		November		December	
ON PEAK KW	OFF PEAK KW	ON PEAK KW	OFF PEAK KW	ON PEAK KW	OFF PEAK KW	ON PEAK KW	OFF PEAK KW	ON PEAK KW	OFF PEAK KWH
1632	2016	432	1056	336	2064	1248	0	3168	432
768	0	672	0	2592	0	1920	0	1248	0
5376	0	2880	0	2400	0	1440	0	3456	288
2304	48	1056	0	1872	0	528	0	2928	48
2112	48	576	0	960	0	1344	0	2880	48
231600	177600	106800	78000	85200	74400	58800	91200	70800	103200
1200	1200	1200	1200	1200	0	0	0	0	1200
39600	30000	37200	26400	45600	19200	29400	64800	48000	48600
768	384	960	192	576	768	1152	960	960	2880
		11280	7200	5520	1600	2960	800	1600	560

SECURITY LIGHT Type	KWH	Watts
1	57	100/175
1	57	100/175
1	57	100/175
1	57	100/175
1	57	100/175
1	57	100/175
1	57	100/175
1	57	100/175
1	57	100/175
1	57	100/175
2	40	100
2	40	100
3	40	100
3	40	100
3	83	250
3	83	250
3	154	400
3	154	400
4	40	100
4	40	100
4	83	250
4	83	250
4	154	400
4	154	400
5	40	100
5	40	100

1/1/2009

Description	SECURITY LIGHT Rate	ORIGINAL RATE
Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	1	5.51
Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	2	7.19
Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	3	8.87
Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	4	10.55
Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	5	12.23
Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	6	6.01
Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	7	7.69
Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	8	9.37
Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	9	11.05
Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	10	12.73
Regular Area Light - High Pressure Sodium	21	8.85
Regular Area Light - High Pressure Sodium	22	13.54
Cobra - High Pressure Sodium	31	11.54
Cobra - High Pressure Sodium	32	16.23
Cobra - High Pressure Sodium	33	15.56
Cobra - High Pressure Sodium	34	20.25
Cobra - High Pressure Sodium	35	19.18
Cobra - High Pressure Sodium	36	23.87
Directional - High Pressure Sodium	41	10.8
Directional - High Pressure Sodium	42	15.49
Directional - High Pressure Sodium	43	13.14
Directional - High Pressure Sodium	44	17.83
Directional - High Pressure Sodium	45	16.52
Directional - High Pressure Sodium	46	21.21
Traditional Light with Fiberglass pole (High Pressure Sodium)	51	9.33
Holophane Light with Fiverglass pole (High Pressure Sodium)	52	11.11

Effective Dates
4/1/2009 7/1/2009 8/1/2009

NEW RATE		NEW RATE		NEW RATE	Notes
5.87	$	7.91	$	8.46	
7.66	$	9.65	$	10.20	
9.46	$	11.39	$	11.94	
11.25	$	13.13	$	13.68	
13.04	$	14.88	$	15.43	
6.4	$	8.58	$	9.13	(add transformer)
8.19	$	10.32	$	10.87	" "
9.99	$	12.06	$	12.61	" "
11.78	$	13.80	$	14.35	" "
13.57	$	15.55	$	16.10	" "
9.43	$	9.69	$	10.12	
14.43	$	14.38	$	14.81	add pole
12.3	$	12.62	$	13.05	
17.3	$	17.31	$	17.74	add pole
16.59	$	17.02	$	17.90	
21.59	$	21.71	$	22.59	add pole
20.45	$	20.99	$	22.63	
25.45	$	25.68	$	27.32	add pole
11.51	$	11.81	$	12.24	
16.51	$	16.50	$	16.93	add pole
14.01	$	14.37	$	15.25	
19.01	$	19.06	$	19.94	add pole
17.61	$	18.09	$	19.73	
22.61	$	22.78	$	24.42	add pole
9.95	$	12.47	$	12.90	Traditional Light with Fiberglass pole
11.84	$	14.84	$	15.27	Holophane Light with Fiverglass pole

Rebecca Witt

From: Mike Cobb
Sent: Tuesday, April 27, 2010 2:42 PM
To: Rebecca Witt
Subject: RE: Flow-through Rates
Attachments: EKP Rate Case Data.xls; EKP WORKSHEET MONTHLY REVENUE with numbers.xlsx

Please send to Charlene & Ann (EKPC) and Kathy Cobb (PSE).

Michael L. Cobb
Owen Electric Cooperative, Inc.
8205 Hwy 127 N.
Owenton, Kentucky 40359
502/563-3533

From: Rebecca Witt
Sent: Monday, April 26, 2010 5:25 PM
To: Mike Cobb
Subject: RE: Flow-through Rates

That works for me. Can we meet at 2:00 or 2:30?

From: Mike Cobb
Sent: Monday, April 26, 2010 4:51 PM
To: Rebecca Witt; Judy Osborne
Subject: RE: Flow-through Rates

We just sent the tariff sheets this afternoon, so we can check that off the list. But it looks like Charlene has a list of other stuff. Let's meet tomorrow, if possible to see what else we can supply.

Michael L. Cobb
Owen Electric Cooperative, Inc.
8205 Hwy 127 N.
Owenton, Kentucky 40359
502/563-3533

From: Rebecca Witt
Sent: Monday, April 26, 2010 9:39 AM
To: Mike Cobb
Subject: FW: Flow-through Rates

Mike,

See Charlene's request below. I thought I had forwarded this already, but couldn't find where that was done. If you already have this, just disregard. We can get together and discuss, if needed.

Thanks,
Becky

From: Charlene Creager [mailto:charlene.creager@ekpc.coop]
Sent: Friday, April 23, 2010 5:27 PM

PSE Rate Study Revenue Data Request

Unit Sales and Revenue Data by Month by Rate Class
Data for Jan 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1] (kWh)	Energy (kWh) Sales: Billed[2] (kWh)	Energy (kWh) Sales: Submetered (kWh)	Demand (kW) Sales: Metered (kW)	Demand (kW) Sales: Billed[3] (kW)	Revenues: Base Rate[4] ($)	Revenues: FCA ($)	Revenues: Environmental Surcharge ($)	Revenues: Total ($)
Rate 1	Schedule 1-Residential	53,745		82,291,735	82,291,735	n/a			6,498,763	1,105,346	550,347	8,154,456
Rate 3	Schedule 1-Small Commercial	2,302		4,349,048	4,349,048	n/a	8,798	8,798	341,187	58,493	29,035	428,715
Rate 4	Schedule II-Large Commercial		242	13,519,797	13,519,797	n/a	40,188	41,088	963,908	181,679	82,191	1,227,778
Rate 5	Primary Metered		3	80,400	80,400	n/a	2,839	2,839	56,455	10,806	4,823	72,084
Rate 6	Outdoor Light Only					n/a			132		1,514	1,646
Rate 9	Schedule XI- LPB1		10	5,830,608	5,830,608	n/a	13,388	13,388	371,852	78,363	32,280	482,495
Rate 10	ETS Off-Peak	8		6,994	6,994	n/a			316	91	29	436
Rate 12	Schedule XIV LPB		4	949,665	949,665	n/a	2,517	2,517	69,830	10,989	5,795	86,614
Rate 13	Scheudle XIII-LPB2		2	9,721,225	9,721,225	n/a	16,586	16,586	437,865	129,897	40,709	608,471
Rate 20	Large Commercial Time-of-Day		9	5,065,440	5,065,440	n/a			21,491	4,121		25,612
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,807		443,672	443,672							48,820
	Rate 2	1,478		84,145	84,145							11,738
	Rate 3	79		4,503	4,503							761
	Rate 4	7		399	399							79
	Rate 6	133		7,636	7,636							907
	Rate 7	51		2,907	2,907							431
	Rate 8	5		285	285							51
	Rate 21	2,607		99,211	99,211							23,300
	Rate 22	353		13,599	13,599							4,797
	Rate 31	7		280	280							85
	Rate 32	14		560	560							235
	Rate 33	7		498	498							100
	Rate 34	4		304	304							78
	Rate 35	15		2,310	2,310							319
	Rate 36	5		770	770							130
	Rate 41	12		448	448							127
	Rate 42	6		240	240							96
	Rate 43	18		1,494	1,494							257
	Rate 44	7		581	581							133
	Rate 45	61		9,394	9,394							1,134
	Rate 46	10		1,540	1,540							233
	Rate 51	290		11,600	11,600							2,861
	Rate 52	168		6,680	6,680							1,956
TOTAL		69,199		122,507,968			84,316	85,216	8,761,799	1,579,785		11,186,935

Notes

1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request

Unit Sales and Revenue Data by Month by Rate Class
Data for Feb 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	No. of Consumers Three Phase	Energy (kWh) Sales Metered[1] (kWh)	Energy (kWh) Sales Billed[2] (kWh)	Energy (kWh) Sales Submetered (kWh)	Demand (kW) Sales Metered (kW)	Demand (kW) Sales Billed[3] (kW)	Revenues Base Rate[4] ($)	Revenues FCA ($)	Revenues Environmental Surcharge ($)	Revenues Total ($)
Rate 1	Schedule 1-Residential	53,884		82,244,810	82,244,810	n/a			6,495,654	415,069	518,492	7,429,215
Rate 3	Schedule I-Small Commercial	2,267		4,456,989	4,456,989	n/a	8,921	8,921	349,217	22,498	27,988	399,703
Rate 4	Schedule II-Large Commercial		245	14,381,317	14,381,317	n/a	38,472	38,472	1,004,634	72,573	80,088	1,157,295
Rate 5	Primary Metered		4	1,121,400	1,121,400	n/a	4,507	4,507	82,052	5,663	6,517	94,232
Rate 6	Outdoor Light Only					n/a			132		1,498	1,630
Rate 9	Schedule XI- LPB1		10	5,534,733	5,534,733	n/a	11,835	11,835	327,286	27,950	26,394	381,630
Rate 10	ETS Off-Peak	8		6,129	6,129	n/a			277	30	23	330
Rate 12	Schedule XIV LPB		4	1,009,480	1,009,480	n/a	2,522	2,522	71,138	4,431	5,615	81,184
Rate 13	Scheudle XIII-LPB2		2	10,149,576	10,149,576	n/a	16,930	16,930	462,642	50,480	38,125	551,247
Rate 20	Large Commercial Time-of-Day		9	301,776	301,776	n/a			20,928	1,524		22,452
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,767		442,044	442,044							44,920
	Rate 2	1,472		83,800	83,800							10,985
	Rate 3	79		4,503	4,503							723
	Rate 4	7		399	399							76
	Rate 6	134		7,558	7,558							834
	Rate 7	51		2,907	2,907							406
	Rate 8	5		285	285							48
	Rate 21	2,616		101,097	101,097							22,898
	Rate 22	353		13,807	13,807							4,756
	Rate 31	7		280	280							82
	Rate 32	14		560	560							230
	Rate 33	7		581	581							112
	Rate 34	4		332	332							83
	Rate 35	15		2,310	2,310							299
	Rate 36	5		770	770							123
	Rate 41	11		432	432							119
	Rate 42	6		240	240							94
	Rate 43	19		1,577	1,577							257
	Rate 44	7		581	581							128
	Rate 45	61		9,394	9,394							1,055
	Rate 46	10		1,540	1,540							220
	Rate 51	300		11,600	11,600							2,764
	Rate 52	184		7,320	7,320							2,081
TOTAL		69,293		119,900,127			83,187	83,187	8,813,960	600,218		10,212,211

Notes

1. For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2. For use if kWh billed is different from kWh metered due to kWh minimums
3. kW Demand billed should include adjustments for contract minimums, ratchets and power factor.
4. Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Mar 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	No. of Consumers Three Phase	Energy (kWh) Sales Metered[1] (kWh)	Energy (kWh) Sales Billed[2] (kWh)	Energy (kWh) Sales Submetered (kWh)	Demand (kW) Sales Metered (kW)	Demand (kW) Sales Billed[3] (kW)	Revenues Base Rate[4] ($)	Revenues FCA ($)	Revenues Environmental Surcharge ($)	Revenues Total ($)
Rate 1	Schedule 1-Residential	53,940		62,687,499	6,287,499	n/a			5,022,023	407,817	407,419	5,837,259
Rate 3	Schedule 1-Small Commercial	2,264		3,848,935	3,848,935	n/a	9,075	9,075	303,305	25,060	24,703	353,068
Rate 4	Schedule II-Large Commercial		258	13,094,070	13,094,070	n/a	38,192	38,192	929,967	85,229	75,277	1,090,473
Rate 5	Primary Metered		5	1,234,200	1,234,200	n/a	3,976	3,976	87,731	8,035	7,096	102,862
Rate 6	Outdoor Light Only					n/a			132		1,503	1,635
Rate 9	Schedule XI- LPB1		9	5,322,068	5,322,068	n/a	11,692	11,692	326,446	34,647	26,757	387,850
Rate 10	ETS Off-Peak	8		4,394	4,394	n/a			199	27	17	243
Rate 12	Schedule XIV LPB		4	1,000,869	1,000,869	n/a	2,496	2,496	71,662	5,656	5,729	83,047
Rate 13	Scheudle XIII-LPB2		2	9,131,538	9,131,538	n/a	16,325	16,325	416,016	58,727	35,179	509,922
Rate 20	Large Commercial Time-of-Day		9	258,408	258,408	n/a			17,970	1,682		19,652
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,755		441,812	441,812							45,583
	Rate 2	1,467		82,780	82,780							10,978
	Rate 3	78		4,446	4,446							721
	Rate 4	7		399	399							76
	Rate 6	130		7,410	7,410							829
	Rate 7	51		2,901	2,901							410
	Rate 8	5		285	285							49
	Rate 21	2,617		102,617	102,617							23,384
	Rate 22	355		13,697	13,697							4,738
	Rate 31	7		280	280							83
	Rate 32	14		560	560							231
	Rate 33	7		581	581							113
	Rate 34	4		332	332							83
	Rate 35	15		2,310	2,310							303
	Rate 36	5		770	770							124
	Rate 41	11		440	440							122
	Rate 42	6		240	240							95
	Rate 43	19		1,577	1,577							260
	Rate 44	7		581	581							129
	Rate 45	61		9,394	9,394							1,069
	Rate 46	14		1,540	1,540							262
	Rate 51	290		11,587	11,587							2,778
	Rate 52	184		7,320	7,320							2,091
TOTAL		69,321		97,275,840			81,756	81,756	7,175,451	626,880		8,480,522

Notes

1. For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2. For use if kWh billed is different from kWh metered due to kWh minimums
3. kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4. Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Apr 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	No. of Consumers Three Phase	Energy (kWh) Sales Metered[1] (kWh)	Energy (kWh) Sales Billed[2] (kWh)	Energy (kWh) Sales Submetered (kWh)	Demand (kW) Sales Metered (kW)	Demand (kW) Sales Billed[3] (kW)	Revenues Base Rate[4] ($)	Revenues FCA ($)	Revenues Environmental Surcharge ($)	Revenues Total ($)
Rate 1	Schedule 1-Residential	53,946		50,360,899	50,360,899	n/a			4,220,783	459,325	344,655	5,024,763
Rate 3	Schedule 1-Small Commercial	2,254		3,784,328	3,784,328	n/a	8,380	8,380	304,998	34,204	24,849	364,051
Rate 4	Schedule II-Large Commercial		255	12,680,464	12,680,464	n/a	40,612	40,612	940,007	115,754	76,597	1,132,358
Rate 5	Primary Metered		5	1,424,400	1,424,400	n/a	4,594	4,594	100,135	13,005	8,203	121,343
Rate 6	Outdoor Light Only					n/a			113		1,590	1,703
Rate 9	Schedule XI- LPB1		9	5,649,724	5,649,724	n/a	11,726	11,726	327,517	51,582	27,479	406,578
Rate 10	ETS Off-Peak	8		3,129	3,129	n/a			147	27	13	187
Rate 12	Schedule XIV LPB		4	989,045	989,045	n/a	2,477	2,477	71,034	7,825	5,717	84,576
Rate 13	Scheudle XIII-LPB2		2	8,996,511	8,996,511	n/a	16,182	16,182	411,096	81,221	35,693	528,010
Rate 20	Large Commercial Time-of-Day		9	249,456	249,456	n/a			17,765	2,278		20,043
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,721		440,513	440,513							49,376
	Rate 2	1,462		81,833	81,833							11,758
	Rate 3	79		4,503	4,503							788
	Rate 4	7		399	399							82
	Rate 6	130		7,410	7,410							900
	Rate 7	50		2,850	2,850							436
	Rate 8	5		285	285							53
	Rate 21	2,659		100,545	100,545							24,658
	Rate 22	351		13,712	13,712							5,083
	Rate 31	7		280	280							89
	Rate 32	14		560	560							247
	Rate 33	7		581	581							121
	Rate 34	4		332	332							89
	Rate 35	15		2,310	2,310							328
	Rate 36	5		770	770							134
	Rate 41	21		613	613							182
	Rate 42	6		240	240							101
	Rate 43	21		1,718	1,718							306
	Rate 44	8		611	611							146
	Rate 45	61		9,394	9,394							1,160
	Rate 46	14		1,540	1,540							320
	Rate 51	290		11,600	11,600							2,991
	Rate 52	184		7,320	7,320							2,244
TOTAL		69,329		84,827,875			83,971	83,971	6,393,595	765,221		7,785,204

Notes
1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for May 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1] (kWh)	Energy (kWh) Sales: Billed[2] (kWh)	Energy (kWh) Sales: Submetered (kWh)	Demand (kW) Sales: Metered (kW)	Demand (kW) Sales: Billed[3] (kW)	Revenues: Base Rate[4] ($)	Revenues: FCA ($)	Revenues: Environmental Surcharge ($)	Revenues: Total ($)
Rate 1	Schedule 1-Residential	54,076		45,778,062	45,778,062	n/a			3,995,924	465,941	331,666	4,793,531
Rate 3	Schedule 1-Small Commercial	2,251		3,616,036	3,616,036	n/a	8,600	8,600	302,874	36,452	25,134	364,460
Rate 4	Schedule II-Large Commercial		259	12,458,551	12,458,551	n/a	41,525	41,525	971,718	126,932	80,367	1,179,017
Rate 5	Primary Metered		5	1,616,400	1,616,400	n/a	5,188	5,188	118,193	16,471	9,844	144,508
Rate 6	Outdoor Light Only					n/a			132		1,630	1,762
Rate 9	Schedule XI- LPB1		9	5,158,093	5,158,093	n/a	11,991	11,991	340,336	52,561	28,721	421,618
Rate 10	ETS Off-Peak	8		797	797	n/a			38	6	3	47
Rate 12	Schedule XIV LPB		4	969,945	969,945	n/a	2,557	2,557	76,059	8,539	6,184	90,782
Rate 13	Scheudle XIII-LPB2		2	8,286,492	8,286,492	n/a	14,400	14,400	428,181	81,668	37,270	547,119
Rate 20	Large Commercial Time-of-Day		9	261,216	261,216	n/a			20,060	2,662		22,722
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,694		437,945	437,945							49,556
	Rate 2	1,461		83,056	83,056							12,007
	Rate 3	79		4,503	4,503							793
	Rate 4	7		399	399							83
	Rate 6	130		7,410	7,410							907
	Rate 7	50		2,850	2,850							439
	Rate 8	5		285	285							53
	Rate 21	2,709		105,241	105,241							25,860
	Rate 22	366		14,907	14,907							5,514
	Rate 31	12		480	480							152
	Rate 32	14		560	560							248
	Rate 33	7		581	581							122
	Rate 34	4		332	332							90
	Rate 35	16		2,346	2,346							335
	Rate 36	5		770	770							135
	Rate 41	24		924	924							275
	Rate 42	6		240	240							101
	Rate 43	22		1,826	1,826							327
	Rate 44	8		664	664							159
	Rate 45	62		9,481	9,481							1,181
	Rate 46	16		1,715	1,715							349
	Rate 51	290		11,600	11,600							3,004
	Rate 52	184		7,320	7,320							2,252
TOTAL		69,506		78,841,027			84,261	84,261	6,253,515	791,232		7,669,508

Notes

1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Jun 2009

Rate Code	Applicable Rate Schedule	No. of Consumers		Energy (kWh) Sales			Demand (kW) Sales		Revenues			
		Single Phase	Three Phase	Metered[1]	Billed[2]	Submetered	Metered	Billed[3]	Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
Rate 1	*Schedule 1-Residential*	54,049		50,300,883	50,300,883	n/a			4,358,961	331,178	371,525	5,061,664
Rate 3	Schedule 1-Small Commercial	2,279		3,542,718	3,542,718	n/a	9,241	9,241	298,739	23,351	25,553	347,643
Rate 4	Schedule II-Large Commercial		240	12,455,699	12,455,699	n/a	42,478	42,478	976,214	82,070	82,604	1,140,888
Rate 5	Primary Metered		5	1,692,600	1,692,600	n/a	5,681	5,681	125,083	11,154	10,627	146,864
Rate 6	Outdoor Light Only					n/a			122		1,702	1,824
Rate 9	Schedule XI- LPB1		9	5,357,970	5,357,970	n/a	11,963	11,963	337,484	35,309	29,078	401,871
Rate 10	ETS Off-Peak	8		208	208	n/a			10	1	1	12
Rate 12	Schedule XIV LPB		4	981,784	981,784	n/a	2,735	2,735	76,886	5,600	6,434	88,920
Rate 13	Scheudle XIII-LPB2		2	7,564,046	7,564,046	n/a	13,550	13,550	420,096	49,847	36,656	506,599
Rate 20	Large Commercial Time-of-Day		9	303,240	303,240	n/a			23,789	1,998		25,787
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,662		434,400	434,400							47,566
	Rate 2	1,451		82,544	82,544							11,631
	Rate 3	79		4,503	4,503							777
	Rate 4	7		399	399							81
	Rate 6	130		7,410	7,410							880
	Rate 7	50		2,850	2,850							428
	Rate 8	5		285	285							52
	Rate 21	2,739		105,776	105,776							25,634
	Rate 22	364		14,962	14,962							5,491
	Rate 31	13		520	520							163
	Rate 32	14		560	560							246
	Rate 33	7		581	581							120
	Rate 34	4		332	332							89
	Rate 35	15		2,310	2,310							322
	Rate 36	5		770	770							132
	Rate 41	23		920	920							271
	Rate 42	6		240	240							101
	Rate 43	22		1,826	1,826							320
	Rate 44	8		664	664							156
	Rate 45	62		9,548	9,548							1,155
	Rate 46	16		1,848	1,848							363
	Rate 51	290		11,600	11,600							2,962
	Rate 52	185		7,320	7,320							2,225
TOTAL		69,493		82,891,316			85,648	85,648	6,617,384	540,508		7,823,237

Notes

1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Jul 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1] (kWh)	Energy (kWh) Sales: Billed[2] (kWh)	Energy (kWh) Sales: Submetered (kWh)	Demand (kW) Sales: Metered (kW)	Demand (kW) Sales: Billed[3] (kW)	Revenues: Base Rate[4] ($)	Revenues: FCA ($)	Revenues: Environmental Surcharge ($)	Revenues: Total ($)
Rate 1	Schedule 1-Residential	54,260		62,025,037	62,025,037	n/a			5,581,305	215,027	438,869	6,235,201
Rate 3	Schedule 1-Small Commercial	2,305		4,025,574	4,025,574	n/a	9,496	9,496	353,807	13,990	27,914	395,711
Rate 4	Schedule II-Large Commercial		242	13,161,966	13,161,966	n/a	43,530	43,530	1,028,279	45,559	80,161	1,153,999
Rate 5	Primary Metered		6	2,112,000	2,112,000	n/a	6,062	6,062	151,108	7,329	11,819	170,256
Rate 6	Outdoor Light Only					n/a			132		1,987	2,119
Rate 9	Schedule XI- LPB1		9	5,562,509	5,562,509	n/a	12,194	12,194	356,452	19,302	28,031	403,785
Rate 10	ETS Off-Peak	8				n/a						
Rate 12	Schedule XIV LPB		4	1,062,339	1,062,339	n/a	2,838	2,838	78,573	3,228	6,102	87,903
Rate 13	Scheudle XIII-LPB2		2	8,696,971	8,696,971	n/a	15,251	15,251	409,055	30,178	32,767	472,000
Rate 20	Large Commercial Time-of-Day		9	386,088	386,088	n/a			30,396	1,340	8	31,744
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,634		433,816	433,816							61,671
	Rate 2	1,451		82,351	82,351							14,219
	Rate 3	79		4,486	4,486							912
	Rate 4	7		399	399							93
	Rate 6	131		8,835	8,835							1,306
	Rate 7	50		2,850	2,850							526
	Rate 8	5		285	285							61
	Rate 21	2,800		109,179	109,179							26,799
	Rate 22	364		13,884	13,884							5,050
	Rate 31	13		520	520							166
	Rate 32	14		560	560							244
	Rate 33	7		581	581							121
	Rate 34	4		332	332							88
	Rate 35	15		2,310	2,310							323
	Rate 36	5		770	770							131
	Rate 41	23		920	920							275
	Rate 42	6		240	240							100
	Rate 43	22		1,826	1,826							322
	Rate 44	8		664	664							155
	Rate 45	62		9,548	9,548							1,155
	Rate 46	16		1,848	1,848							359
	Rate 51	296		11,696	11,696							3,687
	Rate 52	183		7,280	7,280							2,737
TOTAL		69,768		97,727,664			89,371	89,371	7,989,107	335,953		9,073,218

Notes
1. For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2. For use if kWh billed is different from kWh metered due to kWh minimums
3. kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4. Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Aug 2009

		No. of Consumers		Energy (kWh) Sales			Demand (kW) Sales		Revenues			
Rate Code	Applicable Rate Schedule	Single Phase	Three Phase	Metered[1]	Billed[2]	Submetered	Metered	Billed[3]	Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
Rate 1	Schedule 1-Residential	54,205		62,459,556	62,459,556	n/a			5,907,975	-21,839	465,517	6,351,653
Rate 3	Schedule 1-Small Commercial	2,293		4,202,306	4,202,306	n/a	9,739	9,739	383,845	-1,471	30,309	412,683
Rate 4	Schedule II-Large Commercial		244	13,812,569	13,812,569	n/a	42,278	42,278	1,089,835	-4,834	84,642	1,169,643
Rate 5	Primary Metered		6	2,280,000	2,280,000	n/a	6,162	6,162	164,583	-798	12,759	176,544
Rate 6	Outdoor Light Only					n/a			121		2,157	2,278
Rate 9	Schedule XI- LPB1		9	5,671,114	5,671,114	n/a	12,155	12,155	356,415	-1,984	27,610	382,041
Rate 10	ETS Off-Peak	8				n/a						
Rate 12	Schedule XIV LPB		4	1,049,556	1,049,556	n/a	2,667	2,667	77,218	-321	5,990	82,887
Rate 13	Scheudle XIII-LPB2		3	9,579,768	9,579,768	n/a	15,781	15,781	444,830	-3,353	34,391	475,868
Rate 20	Large Commercial Time-of-Day		9	496,656	496,656	n/a			39,612	-174	3,072	42,510
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,604		431,538	431,538							63,970
	Rate 2	1,440		83,175	83,175							14,807
	Rate 3	80		4,477	4,477							937
	Rate 4	7		399	399							96
	Rate 6	132		7,494	7,494							1,199
	Rate 7	50		2,850	2,850							543
	Rate 8	5		285	285							63
	Rate 21	2,832		109,215	109,215							27,628
	Rate 22	366		14,221	14,221							5,275
	Rate 31	13		520	520							170
	Rate 32	14		560	560							248
	Rate 33	7		581	581							125
	Rate 34	4		332	332							90
	Rate 35	15		2,310	2,310							339
	Rate 36	5		770	770							136
	Rate 41	23		920	920							281
	Rate 42	6		240	240							102
	Rate 43	22		1,826	1,826							335
	Rate 44	8		664	664							159
	Rate 45	62		9,548	9,548							1,220
	Rate 46	16		1,848	1,848							372
	Rate 51	300		12,000	12,000							3,866
	Rate 52	183		7,280	7,280							2,787
TOTAL		69,700		100,244,578			88,782	88,782	8,464,434	-34,774		9,220,855

Notes

1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums.
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 *Outdoor Lighting revenues should be shown as separate rate class.*

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Sep 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1] (kWh)	Energy (kWh) Sales: Billed[2] (kWh)	Energy (kWh) Sales: Submetered (kWh)	Demand (kW) Sales: Metered (kW)	Demand (kW) Sales: Billed[3] (kW)	Revenues: Base Rate[4] ($)	Revenues: FCA ($)	Revenues: Environmental Surcharge ($)	Revenues: Total ($)
Rate 1	Schedule 1-Residential	54,190		57,812,426	57,812,426	n/a			5,855,689	59,514	469,013	6,384,216
Rate 3	Schedule 1-Small Commercial	2,318		3,988,486	3,988,486	n/a	9,308	9,308	393,538	4,108	31,572	429,218
Rate 4	Schedule II-Large Commercial		236	13,721,856	13,721,856	n/a	43,899	43,899	1,209,832	14,131	95,661	1,319,624
Rate 5	Primary Metered		6	2,448,000	2,448,000	n/a	6,554	6,554	197,209	2,521	15,599	215,329
Rate 6	Outdoor Light Only					n/a			132		2,166	2,298
Rate 9	Schedule XI- LPB1		9	6,040,725	6,040,725	n/a	12,694	12,694	440,626	6,222	34,899	481,747
Rate 10	ETS Off-Peak	8				n/a						
Rate 12	Schedule XIV LPB		7	1,092,845	1,092,845	n/a	2,797	2,797	95,879	990	7,565	104,434
Rate 13	Scheudle XIII-LPB2		2	10,097,125	10,097,125	n/a	16,168	16,168	572,517	10,400	45,526	628,443
Rate 20	Large Commercial Time-of-Day		10	277,104	277,104	n/a			25,184	285	1,989	27,458
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,550		428,023	428,023							63,823
	Rate 2	1,428		81,033	81,033							14,579
	Rate 3	78		4,414	4,414							929
	Rate 4	7		399	399							96
	Rate 6	132		7,429	7,429							1,197
	Rate 7	50		2,850	2,850							546
	Rate 8	5		285	285							63
	Rate 21	2,872		110,418	110,418							28,163
	Rate 22	381		14,686	14,686							5,465
	Rate 31	13		520	520							170
	Rate 32	14		560	560							249
	Rate 33	7		581	581							126
	Rate 34	4		332	332							91
	Rate 35	15		2,310	2,310							342
	Rate 36	5		770	770							137
	Rate 41	23		920	920							282
	Rate 42	7		185	185							92
	Rate 43	22		1,798	1,798							332
	Rate 44	7		581	581							140
	Rate 45	62		9,548	9,548							1,233
	Rate 46	16		1,848	1,848							374
	Rate 51	300		12,000	12,000							3,882
	Rate 52	183		7,280	7,280							2,797
TOTAL		69,697		96,167,337			91,420	91,420	8,790,606	98,171		9,717,875

Notes

1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request

Unit Sales and Revenue Data by Month by Rate Class
Data for Oct 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1] (kWh)	Energy (kWh) Sales: Billed[2] (kWh)	Energy (kWh) Sales: Submetered (kWh)	Demand (kW) Sales: Metered (kW)	Demand (kW) Sales: Billed[3] (kW)	Revenues: Base Rate[4] ($)	Revenues: FCA ($)	Revenues: Environmental Surcharge ($)	Revenues: Total ($)
Rate 1	Schedule 1-Residential	54,231		47,108,214	47,108,214	n/a			4,879,009	-492,701	372,366	4,758,674
Rate 3	Schedule 1-Small Commercial	240		3,700,418	3,700,418	n/a	9,145	9,145	367,630	-38,732	27,916	356,814
Rate 4	Schedule II-Large Commercial		239	13,851,659	13,851,659	n/a	42,774	42,774	1,208,077	-145,006	88,623	1,151,694
Rate 5	Primary Metered		7	2,571,600	2,571,600	n/a	6,911	6,911	207,219	-26,925	15,036	195,330
Rate 6	Outdoor Light Only					n/a			132		2,191	2,323
Rate 9	Schedule XI- LPB1		9	5,658,847	5,658,847	n/a	12,210	12,210	430,664	-59,248	30,939	402,355
Rate 10	ETS Off-Peak	9		829	829	n/a			45	-9	3	39
Rate 12	Schedule XIV LPB		3	632,306	632,306	n/a	1,848	1,848	64,452	-5,238	4,933	64,147
Rate 13	Scheudle XIII-LPB2		2	9,614,292	9,614,292	n/a	16,012	16,012	555,775	-100,662	37,911	493,024
Rate 20	Large Commercial Time-of-Day		10	244,288	244,288	n/a			22,377	-2,558	1,651	21,470
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,498		424,066	424,066							58,552
	Rate 2	1,414		80,446	80,446							13,550
	Rate 3	75		4,275	4,275							851
	Rate 4	7		399	399							92
	Rate 6	131		7,395	7,395							1,107
	Rate 7	50		2,820	2,820							508
	Rate 8	5		285	285							60
	Rate 21	2,901		112,298	112,298							27,240
	Rate 22	390		14,160	14,160							5,122
	Rate 31	14		560	560							177
	Rate 32	14		560	560							242
	Rate 33	7		581	581							119
	Rate 34	4		332	332							87
	Rate 35	15		2,310	2,310							315
	Rate 36	5		770	770							129
	Rate 41	28		1,645	1,645							491
	Rate 42	6		240	240							99
	Rate 43	20		1,660	1,660							288
	Rate 44	7		581	581							134
	Rate 45	61		9,394	9,394							1,105
	Rate 46	17		2,002	2,002							376
	Rate 51	321		12,605	12,605							3,933
	Rate 52	183		7,016	7,016							2,615
TOTAL		67,653		84,068,853		0	88,900	88,900	7,735,380	-871,079		7,563,062

Notes

1. For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period.
2. For use if kWh billed is different from kWh metered due to kWh minimums.
3. kW Demand billed should include adjustments for contract minimums, ratchets and power factor.
4. Outdoor Lighting revenues should be shown as separate rate class.

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Nov 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	No. of Consumers Three Phase	Energy (kWh) Sales Metered[1] (kWh)	Energy (kWh) Sales Billed[2] (kWh)	Energy (kWh) Sales Submetered (kWh)	Demand (kW) Sales Metered (kW)	Demand (kW) Sales Billed[3] (kW)	Revenues Base Rate[4] ($)	Revenues FCA ($)	Revenues Environmental Surcharge ($)	Revenues Total ($)
Rate 1	Schedule 1-Residential	54,364		46,171,660	46,171,660	n/a			4,794,104	-360,409	292,801	4,726,496
Rate 3	Schedule 1-Small Commercial	2,332		3,400,980	3,400,980	n/a	8,664	8,664	340,171	-26,597	20,727	334,301
Rate 4	Schedule II-Large Commercial		235	12,221,506	12,221,506	n/a	38,846	38,846	1,076,980	-95,556	63,651	1,045,075
Rate 5	Primary Metered		8	2,264,400	2,264,400	n/a	6,742	6,742	186,284	-17,708	10,928	179,504
Rate 6	Outdoor Light Only					n/a			81		1,720	1,801
Rate 9	Schedule XI- LPB1		9	5,631,368	5,631,368	n/a	11,062	11,062	419,653	-44,037	24,340	399,956
Rate 10	ETS Off-Peak	8		2,365	2,365	n/a			130	-19	7	118
Rate 12	Schedule XIV LPB		3	594,760	594,760	n/a	1,527	1,527	54,899	-3,619	3,323	54,603
Rate 13	Scheudle XIII-LPB2		2	9,158,786	9,158,786	n/a	15,874	15,874	532,130	-71,622	29,841	490,349
Rate 20	Large Commercial Time-of-Day		10	256,552	256,552	n/a			21,180	-2,006	1,242	20,416
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,457		421,456	421,456							57,399
	Rate 2	1,414		80,352	80,352							13,746
	Rate 3	75		4,234	4,234							853
	Rate 4	7		399	399							93
	Rate 6	129		7,259	7,259							1,106
	Rate 7	48		2,736	2,736							-209
	Rate 8	5		285	285							61
	Rate 21	2,939		113,380	113,380							27,836
	Rate 22	394		15,238	15,238							5,537
	Rate 31	15		597	597							190
	Rate 32	14		560	560							244
	Rate 33	7		581	581							121
	Rate 34	4		332	332							88
	Rate 35	15		2,310	2,310							321
	Rate 36	5		770	770							131
	Rate 41	28		1,120	1,120							334
	Rate 42	6		240	240							100
	Rate 43	18		1,494	1,494							263
	Rate 44	7		581	581							135
	Rate 45	62		9,481	9,481							1,141
	Rate 46	17		2,002	2,002							381
	Rate 51	313		12,520	12,520							3,940
	Rate 52	174		6,920	6,920							2,598
TOTAL		69,857		80,387,224			82,715	82,715	7,425,612	-621,573		7,369,028

Notes
1 *For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period.*
2 For use if kWh billed is different from kWh metered due to kWh minimums
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request

Unit Sales and Revenue Data by Month by Rate Class
Data for Dec 2009

Rate Code	Applicable Rate Schedule	No. of Consumers: Single Phase	No. of Consumers: Three Phase	Energy (kWh) Sales: Metered[1]	Energy (kWh) Sales: Billed[2]	Energy (kWh) Sales: Submetered	Demand (kW) Sales: Metered	Demand (kW) Sales: Billed[3]	Revenues: Base Rate[4]	Revenues: FCA	Revenues: Environmental Surcharge	Revenues: Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
Rate 1	Schedule 1-Residential	54,018		61,208,280	61,208,280	n/a	n/a	n/a	6,165,834	-858,646	60,354	5,367,542
Rate 3	Schedule 1-Small Commercial	2,346		3,736,228	3,736,228		9,158	9,158	370,821	-52,460	3,629	321,990
Rate 4	Schedule II-Large Commercial		237	12,489,310	12,489,310		39,699	39,699	1,100,518	-175,322	10,384	935,580
Rate 5	Primary Metered		8	1,223,400	1,223,400		4,451	4,451	105,233	-17,177	987	89,043
Rate 6	Outdoor Light Only								132		288	420
Rate 9	Schedule XI- LPB1		10	6,177,210	6,177,210		13,098	13,098	460,297	-86,728	21,554	395,123
Rate 10	ETS Off-Peak	8		2,796	2,796				153	-39	1	115
Rate 12/16	Schedule XIV LPB		3	550,781	550,781		1,546	1,546	56,859	-5,880	1,254	52,233
Rate 13	Scheudle XIII-LPB2		13	8,937,506	8,937,506		15,826	15,826	522,244	-125,483	27,819	424,580
Rate 20	Large Commercial Time-of-Day		10	292,296	292,296				24,989	-4,104	234	21,119
	YARD LIGHTS:	NUMBER:										
	Rate 1	7,403		420,343	420,343							56,500
	Rate 2	1,406		79,970	79,970							13,188
	Rate 3	74		5,612	5,612							1,065
	Rate 4	7		399	399							90
	Rate 6	125		7,125	7,125							1,041
	Rate 7	48		2,736	2,736							483
	Rate 8	5		285	285							59
	Rate 21	2,939		116,046	116,046							27,734
	Rate 22	395		15,437	15,437							5,513
	Rate 31	15		600	600							187
	Rate 32	14		560	560							241
	Rate 33	7		581	581							117
	Rate 34	4		332	332							86
	Rate 35	15		2,310	2,310							307
	Rate 36	5		770	770							126
	Rate 41	29		1,160	1,160							339
	Rate 42	6		240	240							98
	Rate 43	18		1,494	1,494							253
	Rate 44	7		581	581							131
	Rate 45	62		9,471	9,471							1,080
	Rate 46	17		2,002	2,002							369
	Rate 51	313		12,520	12,520							3,862
	Rate 52	174		6,920	6,920							2,555
TOTAL		69,460		95,305,301			83,778	83,778	8,807,080	-1,325,839		7,723,169

Notes

1. For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2. For use if kWh billed is different from kWh metered due to kWh minimums
3. kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4. Outdoor Lighting revenues should be shown as separate rate class

PSE Rate Study Revenue Data Request
Unit Sales and Revenue Data by Month by Rate Class
Data for Total 2009

Rate Code	Applicable Rate Schedule	No. of Consumers Single Phase	Three Phase	Energy (kWh) Sales Metered[1]	Billed[2]	Submetered	Demand (kW) Sales Metered	Billed[3]	Revenues Base Rate[4]	FCA	Environmental Surcharge	Total
				(kWh)	(kWh)	(kWh)	(kW)	(kW)	($)	($)	($)	($)
		#DIV/0!	#DIV/0!									
Rate 1	Schedule 1-Resident	54,076	#DIV/0!	710,449,061	654,049,061				63,776,024	1,725,622		70,124,670
Rate 3	Schedule 1-Small C	2,121	#DIV/0!	46,652,046	46,652,046		9,496	108,525	4,110,132	98,896		4,508,357
Rate 4	Schedule II-Large C	#DIV/0!	244	157,848,764	157,848,764		43,530	493,393	12,499,969	303,209		13,703,424
Rate 5	Primary Metered	#DIV/0!	6	20,068,800	20,068,800	#REF!	#REF!	63,667	1,581,285	12,376		1,707,899
Rate 6	Outdoor Light Only	#DIV/0!	#DIV/0!						1,493			21,439
Rate 9	Schedule XI- LPB1	#DIV/0!	9	67,594,969	67,594,969		12,194	146,008	4,495,028	113,939		4,947,049
Rate 10	ETS Off-Peak	8	#DIV/0!	27,641	27,641				1,315	115		1,527
Rate 12	Schedule XIV LPB	#DIV/0!	4	10,883,375	10,883,375		2,838	28,527	864,489	32,200		961,330
Rate 13	Scheudle XIII-LPB2	#DIV/0!	3	109,933,836	109,933,836		15,251	188,885	5,612,447	191,298		6,235,632
Rate 20	Large Commercial T	#DIV/0!	9	8,392,520	8,392,520				285,741	7,048		300,985
		#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!		#REF!
	YARD LIGHTS:	#DIV/0!	#DIV/0!									
	Rate 1	7,650	#DIV/0!	4,779,285	4,779,285							591,236
	Rate 2	1,945	#DIV/0!	1,325,858	1,325,858							196,498
	Rate 3	189	#DIV/0!	128,817	128,817							22,233
	Rate 4	13	#DIV/0!	10,001	10,001							2,012
	Rate 6	121	#DIV/0!	83,645	83,645							11,262
	Rate 7	56	#DIV/0!	38,496	38,496							5,505
	Rate 8	9	#DIV/0!	5,871	5,871							1,097
	Rate 21	2,525	#DIV/0!	1,169,262	1,169,262							283,459
	Rate 22	581	#DIV/0!	272,919	272,919							84,562
	Rate 31	44	#DIV/0!	22,304	22,304							7,274
	Rate 32	14	#DIV/0!	6,648	6,648							2,743
	Rate 33	8	#DIV/0!	6,610	6,610							1,537
	Rate 34	5	#DIV/0!	5,395	5,395							1,252
	Rate 35	18	#DIV/0!	32,862	32,862							4,447
	Rate 36	6	#DIV/0!	11,550	11,550							1,852
	Rate 41	43	#DIV/0!	21,224	21,224							5,619
	Rate 42	22	#DIV/0!	10,185	10,185							3,280
	Rate 43	19	#DIV/0!	17,368	17,368							3,108
	Rate 44	8	#DIV/0!	7,666	7,666							1,694
	Rate 45	57	#DIV/0!	95,311	95,311							11,605
	Rate 46	19	#DIV/0!	27,202	27,202							4,456
	Rate 51	273	#DIV/0!	120,810	120,810							34,176
	Rate 52	195	#DIV/0!	84,896	84,896							28,289
		174	#DIV/0!	6,920	6,920							2,555
		#DIV/0!	#DIV/0!									
		#DIV/0!	#DIV/0!									
		#DIV/0!	#DIV/0!									
TOTAL		69,356		1,140,145,110			89,371	1,029,005	93,227,923	2,484,703		103,824,824

Notes

1 For Time of Use or On Peak / Off Peak Rates use separate lines for each pricing period
2 For use if kWh billed is different from kWh metered due to kWh minimums.
3 kW Demand billed should include adjustments for contract minimums, ratchets and power factor
4 Outdoor Lighting revenues should be shown as separate rate class.
4 Outdoor Lighting revenues should be shown as separate rate class

Rebecca Witt

From: Mike Cobb
Sent: Thursday, May 06, 2010 8:28 AM
To: Rebecca Witt
Subject: FW: Energy Rates
Attachments: EKPC Rate Case Data Apr 27 2010.xls

pass along to PSE (note additional info on B Rate tab)

Michael L. Cobb
Owen Electric Cooperative, Inc.
8205 Hwy 127 N.
Owenton, Kentucky 40359
502/563-3533

From: Mike Cobb
Sent: Wednesday, May 05, 2010 11:39 AM
To: 'Charlene Creager'
Cc: Rebecca Witt
Subject: RE: Energy Rates

Charlene,
Take a look at this spreadsheet. Where we broke out the kWh energy in 1) Actual, 2) less than or equal to 425 hours, and greater than 425 hrs.

Please note that in some cases the actual is less than what we actually billed (due to the min. contract provisions of the B rates).

Michael L. Cobb
Owen Electric Cooperative, Inc.
8205 Hwy 127 N.
Owenton, Kentucky 40359
502/563-3533

From: Charlene Creager [mailto:charlene.creager@ekpc.coop]
Sent: Wednesday, May 05, 2010 9:21 AM
To: Mike Cobb
Subject: Energy Rates

Mike,

Your energy rates for many rate classes are divided by the first 425 kWh/kW and over 425 kWh/kW but I only have billing determinants for total energy. Do you have these amounts split out for 2009? I have calculated everything at the higher rate but I know that isn't right.

Charlene

Analyst, Regulatory Services
East Kentucky Power Cooperative
Phone 859-745-9759
e-mail: charlene.creager@ekpc.coop

To: Rebecca Witt
Cc: Ann Wood
Subject: Flow-through Rates

Becky,

I'm working on your billing analysis for the flow-through tariff changes resulting from EKPC's rate case.

You sent billing determinants but I still need a few things:

Current tariff sheets in electronic format that we can update
Billing determinants for all lighting rates - number of bills, current rates, kWh per lamp, etc.
For any B rates, I need the kW for firm demand and excess demand split out
For Rate 20, Large Commercial Time of day - Are these Owen's rate 2-A? I need the on-peak and off-peak energy numbers.

I will be on vacation next week but I will be checking my e-mail. Let me know if you have questions or you can talk with Ann Wood.

When I return, I will need to finish these analyses right away. Once the calculations are done, we will send to you and Mark Stallons for review before we submit on Owen's behalf. You'll be hearing more from us..

Hope you have a great weekend.

Charlene Creager
Analyst, Regulatory Services
East Kentucky Power Cooperative
Phone 859-745-9759
e-mail: charlene.creager@ekpc.coop

B Rate Billing

KW Demand Splits

	OEC Billing Rate	Rate Sch	January Actual	January Contract	January Exess	February Actual	February Contract	February Exess	March Actual	March Contract	March Exess
Air Liquide	13	XIII LPB2	8233	8500	0	8124	8500	0	8876	8500	376
CW.Zumbiel	9	XI LPB1	1456	1550	0	1486	1550	0	1400	1425	0
Cascades	9	XI LPB1	836	1000	0	789	1000	0	871	1000	0
Cengage	9	XI LPB1	2212	2000	212	2230	2000	230	2166	2000	166
Duro Bag	9	XI LPB1	1259	1524	0	1276	1524	0	1230	1524	0
Mauser	12	XIV LPB	887	800	87	869	800	69	872	800	72
Messier- Bugatti	13	XIII LPB2	8700	7700	1000	8202	8200	2	7304	8200	0
Mississippi Lime	9	XI LPB1	1701	1600	101	1701	1700	1	1721	1700	21
SKF	12 (Jan-Nov) / 16 (Dec)	XIV LPB	456	500	0	464	500	0	449	500	0
Steel Technologies	9	XI LPB1	1345	1100	245	1240	1100	140	1244	1100	144
Toyota Lab	12	XIV LPB	597	700	0	605	700	0	606	700	0
Toyota Headquarters	9	XI LPB1	886	1200	0	885	1200	0	1061	1200	0
Toyota Whse	9	XI LPB1	1223	1200	23	1179	1200	0	1075	1200	0
U.S. Playing Cards	9	XI LPB1									
Xpedx	12 (Jan-Nov) / 16 (Dec)	XIV LPB	582	600	0	559	600	0	550	600	0
ZF Boge	9	XI LPB1	918	1050	0	904	1200	0	956	1050	0
Mubea?	Used to be a rate 9; however, dropped off of B rate in January and currently a rate 5										
Gallatin Materials?	(name changed to Mississippi Lime)										

kWh Energy Splits

	OEC Billing Rate	Rate Sch	January Actual	January Billed </= 425 hrs	January Billed > 425 hrs	February Actual	February Billed </= 425 hrs	February Billed > 425 hrs	March Actual	March Billed </= 425 hrs	March Billed > 425 hrs
Air Liquide	13	XIII LPB2, 15	5,349,520	3,612,500	1,737,020	4,929,649	3,612,500	1,317,149	5,099,525	3,772,300	1,327,225
CW.Zumbiel	9	XI LPB1	690,810	658,750	32,060	717,926	658,750	59,176	812,315	605,625	206,690
Cascades	9	XI LPB1	440,833	425,000	15,833	424,903	425,000		495,557	425,000	70,557
Cengage	9	XI LPB1	1,139,179	940,100	199,079	1,048,509	947,750	100,759	1,182,625	920,550	262,075
Duro Bag	9	XI LPB1	593,868	647,700		563,489	647,700		629,720	647,700	
Mauser	12	XIV LPB	368,072	368,072		383,158	383,158		368,436	368,436	
Messier- Bugatti	13	XIII LPB2	4,800,056	3,697,500	1,102,556	4,201,889	3,485,850	716,039	3,896,986	3,485,000	411,986
Mississippi Lime	9	XI LPB1	828,829	722,925	105,904	823,691	722,925	100,766	654,237	722,500	
SKF	12 (Jan-Nov) / 16 (Dec)	??	166,127	212,500		160,434	212,500		175,647	212,500	
Steel Technologies	9	XI LPB1	542,061	542,061		543,040	527,000	16,040	591,393	528,700	62,693
Toyota Lab	12	XIV LPB	239,618	297,500		239,249	297,500		220,543	297,500	
Toyota Headquarters	9	XI LPB1	477,469	510,000		440,488	510,000		450,890	510,000	
Toyota Whse	9	XI LPB1	460,899	510,000		405,640	510,000		404,783	510,000	
U.S. Playing Cards	9	XI LPB1									
Xpedx	12 (Jan-Nov) / 16 (Dec)	??	235,663	255,000		218,028	255,000		224,419	255,000	
ZF Boge	9	XI LPB1	360,785	446,250		354,382	510,000		428,194	446,250	
Mubea?	Used to be a rate 9; however, dropped off of B rate in January and currently a rate 5										
Gallatin Materials?	(name changed to Mississippi Lime)										

April			May			June			July			August			
Actual	Contract	Exess	Actual	Contract	Exess	Actual	Contract	Exess	Actual	Contract	Exess	Actual	Contract	Exess	Actual
8475	8500	0	8597	8500	97	8283	8500	0	8457	8500	0	8606	8500	106	7907
1498	1425	73	1573	1425	148	1549	1475	74	1561	1475	86	1617	1475	142	1620
855	1000	0	877	1000	0	990	1000	0	986	1000	0	982	1000	0	950
2147	2000	147	1886	2000	0	1975	2000	0	1922	2000	0	1953	2000	0	1811
1287	1524	0	1382	1524	0	1351	1524	0	1305	1524	0	1426	1524	0	1437
896	800	96	879	800	79	880	800	80	874	800	74	861	800	61	
5922	8200	0	4950	7500	0	6969	6800	169	7323	7500	0	7560	7500	60	8100
1744	1700	44	1779	1700	79	1545	1700	0	1648	1700	0	1679	1700	0	1657
503	500	3	578	500	78	575	500	75	568	500	68	581	500	81	561
1255	1100	155	1169	1100	69	1181	1100	81	1181	1100	81	1248	1100	148	1216
609	700	0	717	700	17	818	700	118	682	700	0	766	900	0	680
1209	1200	9	1203	1200	3	1374	1200	174	1230	1200	30	1401	1400	1	1182
1120	1100	20	1221	1100	121	1291	1100	191	1277	1100	177	1324	1100	224	1208
549	600	0	561	600	0	565	600	0	543	600	0	588	600	0	607
878	1050	0	871	1050	0	939	1050	0	1048	1050	0	1063	1100	0	1131

April			May			June			July			August			
	Billed			Billed			Billed			Billed			Billed		
Actual	</= 425 hrs	> 425 hrs	Actual	</= 425 hrs	> 425 hrs	Actual	</= 425 hrs	> 425 hrs	Actual	</= 425 hrs	> 425 hrs	Actual	</= 425 hrs	> 425 hrs	Actual
5,339,242	3,612,500	1,726,742	5,614,627	3,653,725	1,960,902	5,131,405	3,612,500	1,518,905	5,431,347	3,612,500	1,818,847	5,495,179	3,657,550	1,837,629	5,124,926
805,771	636,650	169,121	879,258	668,525	210,733	925,189	658,325	266,864	895,704	663,425	232,279	989,387	687,225	302,162	876,846
481,603	425,000	56,603	484,318	425,000	59,318	508,950	425,000	83,950	541,042	425,000	116,042	542,613	425,000	117,613	495,084
1,032,160	912,475	119,685	898,035	850,000	48,035	1,042,640	850,000	192,640	1,011,541	850,000	161,541	1,020,650	850,000	170,650	931,165
582,617	647,700		617,271	647,700		704,569	647,700	56,869	677,064	647,700	29,364	697,899	647,700	50,199	708,467
371,058	371,058		374,995	374,995		380,462	380,462		378,729	378,729		384,426	384,426		
2,947,250	3,485,000		1,949,419	3,187,500		3,565,566	2,961,825	603,741	4,148,421	3,187,500	960,921	4,601,946	3,213,000	1,388,946	4,489,366
535,980	722,500		746,911	746,911		436,219	722,500		517,783	722,500		595,356	722,500		478,761
174,352	212,500		186,383	212,500		222,545	222,545		221,760	221,760		221,117	221,117		213,761
494,525	494,525		462,105	467,500		547,196	501,925	45,271	560,831	501,925	58,906	633,752	530,400	103,352	640,142
202,629	297,500		212,906	297,500		234,119	297,500		218,417	297,500		246,721	382,500		196,217
435,397	510,000		475,116	510,000		505,128	510,000		492,379	510,000		506,695	595,000		465,871
387,022	467,500		387,626	467,500		427,298	467,500		433,763	467,500		448,702	467,500		405,711
221,906	255,000		207,500	255,000		225,213	255,000		230,650	255,000		240,581	255,000		222,328
403,018	446,250		407,330	446,250		465,320	446,250	19,070	541,007	446,250	94,757	605,671	467,500	138,171	656,800

September Contract	September Exess	October Actual	October Contract	October Exess	November Actual	November Contract	November Exess	December Actual	December Contract	December Exess
8500	0	8204	8500	0	8048	8500	0	7947	8500	0
1425	195	1489	1425	64	1394	1425	0	1509	1425	84
1000	0	885	1000	0	877	1000	0	799	1000	0
2000	0	1571	2000	0	1528	2000	0	1682	1700	0
1524	0	1498	1524	0	1535	1524	11	1414	1524	0
8000	100	7670	8100	0	7775	8100	0	7918	8100	0
1700	0	1282	1700	0	1391	1000	391	1347	1000	347
500	61	476	500	0	442	500	0	442	500	0
1100	116	1228	1100	128	1211	1100	111	1272	1100	172
900	0	546	550	0	559	550	9	539	550	0
1400	0	1015	1000	15	892	1000	0	806	1000	0
1100	108	1003	1100	0	1094	1100	0	1180	1100	80
					2104	2200	0	2048	2100	0
600	7	505	600	0	544	600	0	529	600	0
1050	81	1092	1050	42	1070	1250	0	1162	1250	0

September Billed </= 425 hrs	September Billed > 425 hrs	October Actual	October Billed </= 425 hrs	October Billed > 425 hrs	November Actual	November Billed </= 425 hrs	November Billed > 425 hrs	December Actual	December Billed </= 425 hrs	December Billed > 425 hrs
3,612,500	1,512,426	4,861,087	3,612,500	1,248,587	4,858,959	3,612,500	1,246,459	5,111,009	3,612,500	1,498,509
688,500	188,346	777,381	632,825	144,556	722,802	605,625	117,177	764,124	641,325	122,799
425,000	70,084	480,069	425,000	55,069	460,338	425,000	35,338	432,357	425,000	
850,000	81,165	818,959	850,000		759,020	850,000		863,941	722,500	141,441
647,700	60,767	839,863	647,700	192,163	773,401	652,375	121,026	649,103	647,700	1,403
3,442,500	1,046,866	4,297,699	3,442,500	855,199	4,078,547	3,442,500	636,047	4,201,411	3,442,500	758,911
722,500		477,833	722,500		390,454	425,000		411,969	425,000	
213,761		176,294	212,500		158,678	212,500		162,063	212,500	
516,800	123,342	731,429	521,900	209,529	661,364	514,675	146,689	712,260	540,600	171,660
382,500		202,276	233,750		187,896	233,750		168,226	233,750	38,226
595,000		425,890	425,890		393,953	425,000		422,851	425,000	
467,500		379,265	467,500		362,280	467,500		435,392	467,500	
					1,014,619	935,000	79,619	988,930	892,500	96,430
255,000		216,190	255,000		204,207	255,000		247,255	255,000	
480,675	176,125	700,679	464,100	236,579	638,979	531,250	107,729	598,349	531,250	67,099

Time of Use Billing

Account	Name	January		February		March		April		May		June		July	
		ON PEAK KW	OFF PEAK KW	ON PEAK KW	OFF PEAK KW	ON PEAK KW	OFF PEAK KW	ON PEAK KW	OFF PEAK KW	ON PEAK KW	OFF PEAK KW	ON PEAK KW	OFF PEAK KW	ON PEAK KW	OFF PEAK KW
1544-06	Boone County Fiscal Ct	0	288	0	0	0	0	0	0	0	0	288	1200	912	2208
1544-13	Boone County Fiscal Ct	672	0	0	0	0	0	0	0	672	0	3744	0	1632	0
1544-14	Boone County Fiscal Ct	0	0	0	0	0	0	0	0	96	0	3360	96	4512	0
1544-16	Boone County Fiscal Ct	1536	0	0	0	0	0	0	0	720	0	3888	0	4128	48
1544-17	Boone County Fiscal Ct	576	0	0	48	0	0	0	0	0	0	3504	0	2880	0
74356-04	KY Speedway	98400	134400	114000	157200	85200	120000	73200	106800	82800	102000	124800	106800	177600	140400
74356-14	KY Speedway	1200	1200	1200	2400	2400	1200	1200	2400	0	0	0	1200	2400	1200
88184-03	Nugent Sand Co.	31200	31200	9000	11400	18600	26400	36000	26400	45600	27600	28800	24600	25800	21600
8093-02	Garry Ennis	4416	1536	4608	1920	3264	1344	2496	960	768	960	192	768	192	576
106814-01	Kenton Lakes Sportsplex														
		138000	168624	128808	172968										
			306624												

August		September		October		November		December		Total	
ON PEAK KW	OFF PEAK KW	ON PEAK KW	OFF PEAK KW	ON PEAK KW	OFF PEAK KW	ON PEAK KW	OFF PEAK KW	ON PEAK KW	OFF PEAK KW	ON PEAK KWH	OFF PEAK KWH
1632	2016	432	1056	336	2064	1248	0	3168	432	8,016	9,264
768	0	672	0	2592	0	1920	0	1248	0	13,920	-
5376	0	2880	0	2400	0	1440	0	3456	288	23,520	384
2304	48	1056	0	1872	0	528	0	2928	48	18,960	144
2112	48	576	0	960	0	1344	0	2880	48	14,832	144
231600	177600	106800	78000	85200	74400	58800	91200	70800	103200	1,309,200	1,392,000
1200	1200	1200	1200	1200	0	0	0	0	1200	12,000	13,200
39600	30000	37200	26400	45600	19200	29400	64800	48000	48600	394,800	358,200
768	384	960	192	576	768	1152	960	960	2880	20,352	13,248
		11280	7200	5520	1600	2960	800	1600	560	21,360	10,160
										1,836,960	1,796,744
								Should this total 8,292,520?		3,633,704	

No, 3,633,704 is the correct amount.

The error occurred on the January sheet from the earlier spreadsheet.
The original sheet showed 5,065,440 for Jan TOU; the correct figure
is 306,624 for Jan TOU.

SECURITY LIGHT Type	KWH	Watts	Description	SECURITY LIGHT Rate	ORIGINAL RATE (1/1/2009)	NEW RATE (4/1/2009)	NEW RATE (7/1/2009)	NEW RATE (8/1/2009)	Notes
1	57	100/175	Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	1	5.51	5.87	$ 7.91	$ 8.46	
1	57	100/175	Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	2	7.19	7.66	$ 9.65	$ 10.20	
1	57	100/175	Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	3	8.87	9.46	$ 11.39	$ 11.94	
1	57	100/175	Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	4	10.55	11.25	$ 13.13	$ 13.68	
1	57	100/175	Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	5	12.23	13.04	$ 14.88	$ 15.43	
1	57	100/175	Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	6	6.01	6.4	$ 8.58	$ 9.13	(add transformer)
1	57	100/175	Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	7	7.69	8.19	$ 10.32	$ 10.87	" "
1	57	100/175	Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	8	9.37	9.99	$ 12.06	$ 12.61	" "
1	57	100/175	Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	9	11.05	11.78	$ 13.80	$ 14.35	" "
1	57	100/175	Older SL's (Mix of 175W Mecury Vapor & 100W High Pressure Sodium)	10	12.73	13.57	$ 15.55	$ 16.10	" "
2	40	100	Regular Area Light - High Pressure Sodium	21	8.85	9.43	$ 9.69	$ 10.12	
2	40	100	Regular Area Light - High Pressure Sodium	22	13.54	14.43	$ 14.38	$ 14.81	add pole
3	40	100	Cobra - High Pressure Sodium	31	11.54	12.3	$ 12.62	$ 13.05	
3	40	100	Cobra - High Pressure Sodium	32	16.23	17.3	$ 17.31	$ 17.74	add pole
3	83	250	Cobra - High Pressure Sodium	33	15.56	16.59	$ 17.02	$ 17.90	
3	83	250	Cobra - High Pressure Sodium	34	20.25	21.59	$ 21.71	$ 22.59	add pole
3	154	400	Cobra - High Pressure Sodium	35	19.18	20.45	$ 20.99	$ 22.63	
3	154	400	Cobra - High Pressure Sodium	36	23.87	25.45	$ 25.68	$ 27.32	add pole
4	40	100	Directional - High Pressure Sodium	41	10.8	11.51	$ 11.81	$ 12.24	
4	40	100	Directional - High Pressure Sodium	42	15.49	16.51	$ 16.50	$ 16.93	add pole
4	83	250	Directional - High Pressure Sodium	43	13.14	14.01	$ 14.37	$ 15.25	
4	83	250	Directional - High Pressure Sodium	44	17.83	19.01	$ 19.06	$ 19.94	add pole
4	154	400	Directional - High Pressure Sodium	45	16.52	17.61	$ 18.09	$ 19.73	
4	154	400	Directional - High Pressure Sodium	46	21.21	22.61	$ 22.78	$ 24.42	add pole
5	40	100	Traditional Light with Fiberglass pole (High Pressure Sodium)	51	9.33	9.95	$ 12.47	$ 12.90	Traditional Light with Fiberglass pole
5	40	100	Holophane Light with Fiverglass pole (High Pressure Sodium)	52	11.11	11.84	$ 14.84	$ 15.27	Holophane Light with Fiverglass pole

√Rebecca Witt

From: Laslie, Jeffrey [lasliej@powersystem.org]
Sent: Friday, May 07, 2010 1:42 PM
To: Mark Stallons
Cc: Rebecca Witt; Macke, Rich; Cuellar, Marilyn; Isaac Scott; Kathy Cobb
Subject: EKPC Rate Study - Owen Revenue Requirements
Attachments: JCL-Stallons-5-7-10.pdf; Owen Exhibit 3 5-7-2010.pdf; Owen Exhibit 2 5-7-2010.pdf

Dear Mark,

Attached is a letter with supporting schedules summarizing Owen Electric's revenue requirements for use in the East Kentucky rate study.

Thanks,

Jeff Laslie
Power System Engineering, Inc.
Phone: 317-322-5906
Fax: 317-322-5924
Cell: 317-696-0820
lasliej@powersystem.org

Power System
Engineering, Inc.

Via e-mail

May 7, 2010

Mr. Mark Stallons
President and CEO
Owen Electric Cooperative
P.O. Box 400
Owenton, KY 40359-0400

Subject: EKPC Study - Revenue Requirements Exhibits

Dear Mark:

Enclosed are the following exhibits from the Wholesale & Retail Rates Feasibility Study for your review:

- Exhibit 2 - Statement of Operations - Present Rates; and
- Exhibit 3 - Revenue Requirements Analysis.

EXHIBIT 2 - STATEMENT OF OPERATIONS - PRESENT RATES

Exhibit 2 provides a Statement of Operations for the present rates using: 1) 2009 actual figures and 2) the Pro Forma Test Year (Test Year) which reflects Owen's 2009 actual results with rate schedule revenue and purchased power expense recalculations. The rate schedule revenue for the Test Year has been calculated by Power System Engineering, Inc. (PSE) based on unit sales from 2009 at the present retail rates. This is summarized on page 2 and detailed on pages 3-5.

The calculation of Test Year purchased power expense is detailed on page 6 of Exhibit 2. We have calculated the Test Year purchased power expense using EKPC's present rates and your 2009 purchases.

The determination of Test Year revenue and purchased power expense has been made with an intent to capture the annual effect of the retail and wholesale rates currently in place.

EXHIBIT 3 - REVENUE REQUIREMENTS ANALYSIS

Exhibit 3 provides a determination of revenue requirements. The term revenue requirements refers to a cooperative's total cost of doing business. It is comprised not only of operating expenses but also margin requirements. We have included two methods for determining the margin requirements: 1) a Times Interest Earned Ratio method (TIER) and 2) a Rate of Return on Base (ROR) method.

Comparing the revenue generated by present rates to the revenue requirements allows for the identification of any required increase or decrease.

Table 1 summarizes the initial results of our revenue requirements under the 2.0 TIER Method.

Table 1
Revenue Requirements - Present Rates
2.0 Modified TIER Method

	2009 Actual	**Pro Forma Test Year**
Revenue Requirements	$144,534,426	$145,115,581
Revenue From Present Rates		
Tariff Revenue	139,872,447	140,896,729
Other Operating Revenue	1,874,169	1,874,169
Total Revenue	141,746,616	142,770,898
Required Increase	**$2,787,810**	**$2,344,683**
Percent Increase [1]	**2.0%**	**1.7%**

[1] *Required Increase Divided by Tariff Revenue*

Using a TIER of 2.0, we calculate that Owen could justify a rate increase of approximately $2,344,683 or 1.7 percent. Page 1 of Exhibit 3 shows these results in more detail.

Table 2 summarizes the revenue requirements under the ROR Method.

Table 2
Revenue Requirements - Present Rates
Rate of Return Method

	2009 Actual	**Pro Forma Test Year**
Revenue Requirements	143,910,922	144,492,078
Revenue From Present Rates		
Tariff Revenue	139,872,447	140,896,729
Other Operating Revenue	1,874,169	1,874,169
Total Revenue	141,746,616	142,770,898
Required Increase	**2,164,306**	**1,721,179**
Percent Increase [1]	**1.6**	**1.2**

[1] *Required Increase Divided by Tariff Revenue*

This alternative method is producing a lower revenue requirement than the TIER method and suggests that a $1,721,179 or 1.2 percent is needed. Page 2 of Exhibit 3 shows these results in more detail. You will notice that page 3 and the remaining pages of this exhibit provide information on the ROR revenue requirements method.

For this study, we suggest that the TIER is the preferred method given Owen's familiarity and prior use of a TIER margin requirement.

Please review the enclosed information and calculations carefully, and let us know if any changes need to be made. In the meantime, we are developing the Cost of Service analysis and will send a draft copy as soon as it becomes available. Please feel free to call me at (317) 322-5906 if you should have any questions.

Very truly yours,

Jeffrey C. Laslie
Senior Financial Analyst

KY0591018/mmc

cc: Becky Witt, Owen
Isaac Scott, EKPC
Rich Macke, PSE

Enclosures

Statement of Operations
Present Rates
Test Year - 2009

(a) Line No.	(b) Description	(c) 2009 Actual	(d) Pro Forma Test Year
1	**Operating Revenue**	($)	($)
2	Rate Schedule Revenue	139,872,447 [1]	140,896,729 [1]
3	Other Operating Revenue	1,874,169	1,874,169
4	**Total Operating Revenue**	141,746,616	142,770,898
5	**Operating Expenses**		
6	Purchased Power Expense	110,001,447	110,582,602 [2]
7	Transmission - O&M Expense	-	-
8	Distribution - Operation Expense	5,379,575	5,379,575
9	Distribution - Maintenance Expense	3,863,514	3,863,514
10	Consumer Accounting Expense	3,427,328	3,427,328
11	Consumer Service & Information Expense	559,353	559,353
12	Sales Expense	-	-
13	Administrative & General Expense	2,778,189	2,778,189
14	Depreciation & Amortization Expense	9,253,930	9,253,930
15	Property Tax Expense	-	-
16	Other Tax Expense	138,361	138,361
17	Long-Term Interest Expense	4,564,974	4,564,974
18	Other Interest Expense	282,323	282,323
19	Other Deductions	70,399	70,399
20	**Total Operating Expenses**	140,319,392	140,900,547
21	**Operating Margins**	1,427,224	1,870,351
22	**Operating TIER**	1.31	1.41
23	Plus: Non-Operating Margins - Interest	96,038	96,038
24	Plus: Income (loss) from Equity Investments	-	-
25	Plus: Non-Operating Margins - Other	8,980	8,980
26	Plus: Other Capital Credits	244,923	244,923
27	**Margins Before G&T Capital Credits**	1,777,164	2,220,291
28	**Modified TIER**	1.39	1.49
29	Plus: G&T Capital Credits	3,551,381	3,551,381
30	**Patronage Capital or Margins**	5,328,545	5,771,672
31	**TIER**	2.17	2.26

[1] See Exhibit 2, Schedule A for the Pro Forma Test Year revenue.

[2] See Exhibit 2, Schedule B for the Pro Forma Test Year purchased power expense.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

I. Consumer and Sales Data for the Pro Forma Test Year

(a) Line No.	(b) Description	(c) Avg. No. Cons. [1]	(d) Energy Sales [1]	(e) Billing Demand [1] Non-Coinc.	(f) Coinc.	(g) Actual Revenue [1]	(h) Pro Forma Revenue [2]
			(kWh)	(kW)	(kW)	($)	($)
1	Schedules I: Farm and Home	54,076	710,449,061	NA	NA	70,124,670	70,855,837
2	Schedules I-A: Residential Marketing	8	27,641	NA	NA	1,527	1,395
3	Schedule I: Small Commercial	2,287	46,652,046	NA	NA	4,508,357	4,531,024
4	Schedule II: Large Power	248	177,917,564	557,060.0	NA	15,411,323	15,202,821
5	Schedule 5: Renewable Resource Power			NA	NA	-	
6	Schedule III: Security Lights	9,893	6,371,973	NA	NA	851,282	1,106,058
7	Schedule XI: Large Industrial LPB1	9	67,594,969	146,008.0	NA	4,947,049	4,822,884
8	Schedule XIII: Large Industrial Rate LPB2	3	109,933,836	188,885.0	NA	6,235,632	6,630,260
9	Schedule XIV: Large Industrial Rate LPB	4	10,883,375	28,527.0	NA	961,330	891,748
10	Schedule I OLS: Outdoor Lighting Service	3,369	1,654,663	NA	NA	412,832	480,696
11	Schedule II SOLS: SpecialOutdoor Lighting	467	132,986	NA	NA	67,282	81,486
12	Schedule III SOLS: SpecialOutdoor Lighting			NA	NA		-
13	Schedule 2-A: Large Power - Time of Day	9	3,633,704	NA	NA	300,985	310,955
14	Gallatin Contract	1	858,526,147	1,706,527.0	NA	35,984,650	35,981,564
15	**Total** [3]	56,637	1,993,777,965	2,627,007.0	-	139,806,919	140,896,729

[1] As reported by the Cooperative for 2009.
[2] See Schedule A, pages 3 - 5.
[3] The total number of consumers excludes number of Outdoor Lighting Service and Residential Marketing.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
Schedules I: Farm and Home				
Customer Charge	54,076	/month	$10.87	7,053,630
Energy Charge	710,449,061	/kWh	$0.09126	64,835,581
Fuel Charge	710,449,061	/kWh	($0.00720)	(5,112,350)
Environmental Surcharge			6.1%	4,078,976
				70,855,837
Schedules I-A: Residential Marketing				
Energy Charge	27,641	/kWh	$0.05476	1,514
Fuel Charge	27,641	/kWh	($0.00720)	(199)
Environmental Surcharge			6.1%	80
				1,395
Schedule I: Small Commercial				
Customer Charge	2,287	/month	$12.83	352,157
Energy Charge	46,652,046	/kWh	$0.09118	4,253,734
Fuel Charge	46,652,046	/kWh	($0.00720)	(335,705)
Environmental Surcharge			6.1%	260,839
				4,531,024
Schedule II: Large Power				
Customer Charge	248	/month	$20.50	60,967
Energy Charge	177,917,564	/kWh	$0.06891	12,260,299
Demand Charge	557,060	/kW	$5.90	3,286,654
Fuel Charge	177,917,564	/kWh	($0.00720)	(1,280,284)
Environmental Surcharge			6.1%	875,185
				15,202,821
Schedule III: Security Lights				
120 Volts, where available	7,771	/month	$8.46	788,912
With 1 Pole Added	2,001	/month	$10.20	244,922
With 2 Pole Added	198	/month	$11.94	28,369
With 3 Pole Added	13	/month	$13.68	2,134
With 4 Pole Added	121	/month	$15.43	22,404
Transformer Charge	186	/month	$0.67	1,495
Fuel Charge	6,371,973	/kWh	($0.00720)	(45,852)
Environmental Surcharge			6.1%	63,673
				1,106,058
Schedule XI: Large Industrial LPB1				
Customer Charge	9	/month	$1,464.04	162,508
Energy Charge - 425 Hrs per kW	61,090,580	/kWh	$0.05446	3,326,993
Energy Charge - Over 425 Hrs per kW	6,504,389	/kWh	$0.05038	327,691
Demand Charge - Contract Demand	146,008	/kW	$6.81	994,314
Demand Charge - kW > Contract Demand	12,194	/kW	$9.47	115,477
Fuel Charge	67,594,969	/kWh	($0.00626)	(423,201)
Environmental Surcharge			7.1%	319,101
				4,822,884

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
Schedule XIII: Large Industrial Rate LPB2				
Customer Charge	3	/month	$2,927.05	105,374
Energy Charge - 425 Hrs per kW	83,036,690	/kWh	$0.04971	4,127,754
Energy Charge - Over 425 Hrs per kW	26,897,146	/kWh	$0.04813	1,294,560
Demand Charge - Contract Demand	195,900	/kW	$6.81	1,334,079
Demand Charge - kW > Contract Demand	1,910	/kW	$9.47	18,088
Fuel Charge	109,933,836	/kWh	($0.00626)	(688,277)
Environmental Surcharge			7.1%	438,684
				6,630,260
Schedule XIV: Large Industrial Rate LPB				
Customer Charge	4	/month	$1,464.00	70,272
Energy Charge	10,883,375	/kWh	$0.05600	609,469
Demand Charge - Contract Demand	28,527	/kW	$6.81	194,269
Demand Charge - kW > Contract Demand	2,838	/kW	$9.47	26,876
Fuel Charge	10,883,375	/kWh	($0.00626)	(68,139)
Environmental Surcharge			7.1%	59,002
				891,748
Schedule I OLS: Outdoor Lighting Service				
100 Watt HPS Area	3,106	/month	$10.12	377,193
Cobrahead Lighting				
100 Watt HPS	58	/month	$13.05	9,083
250 Watt HPS	13	/month	$17.90	2,792
400 Watt HPS	24	/month	$22.63	6,517
Directional Lighting				
100 Watt HPS	65	/month	$12.24	9,547
250 Watt HPS	27	/month	$15.25	4,941
400 Watt HPS	76	/month	$19.73	17,994
Pole Charges	655	/month	$4.69	36,863
Fuel Charge	1,654,663	/kWh	($0.00720)	(11,907)
Environmental Surcharge			6.11%	27,672
				480,696
Schedule II SOLS: SpecialOutdoor Lighting				
Traditional Light W/ Fiberglass Pole	275	/month	$12.90	42,570
Holophane Light W/ Fiberglass Pole	192	/month	$15.27	35,182
Fuel Charge	132,986	/kWh	($0.00720)	(957)
Environmental Surcharge			6.11%	4,691
				81,486
Schedule III SOLS: SpecialOutdoor Lighting				
Facilities Charge (1.75 x total investment)		/month	$0.00	-
Energy Charge		/kWh	$0.063902	-
Fuel Charge		/kWh	($0.007196)	-
Environmental Surcharge			6.11%	0
				-
Schedule 2-A: Large Power - Time of Day				
Customer Charge	9	/month	$59.00	6,608
Energy Charge - On Peak	1,836,960	/kWh	$0.105948	194,622
Energy Charge - Off Peak	1,796,744	/kWh	$0.064171	115,299
Fuel Charge	3,633,704	/kWh	($0.0071959)	(26,148)
Environmental Surcharge			7.09%	20,574
				310,955

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
Special Contracts				
Gallatin				
Firm Demand	180,000.0	/kW	$6.63	1,193,400
10-Min Intter. Demand	1,426,898.0	/kW	$1.03	1,469,705
90-Min Interr. Demand	99,629.0	/kW	$2.43	242,098
Total Demand Charge	1,706,527.0			2,905,203
On-Peak Energy	211,869,199.0	/kWh	$0.04713	9,984,972
Off-Peak Energy	581,794,340.0	/kWh	$0.04384	25,508,191
Min. Energy On-Peak	18,804,206.0	/kWh	$0.00815	153,196
Min Energy Off-Peak	46,058,402.0	/kWh	$0.00604	278,406
Buy-Thru Chg, Cr On-Pk				113,084
Buy-Thru Chg, Cr Off-Pk				10,798
Energy Charge				36,048,647
Load Following Charge				325,000
FAC Charge	858,526,147.0	/kWh	($0.00726)	(6,233,618)
Distribution Demand Charge	1,706,527.0		$0.03750	63,995
Distribution Energy Charge	858,526,147.0	/kWh	$0.00029	244,680
Environmental Surcharge			7.95%	2,627,657
				35,981,564

Schedule B
Estimate of Pro Forma Test Year Purchased Power Expense

(a) Line No.	(b) Description	(c) Units [1]		(d) Rate [2]		(e) Cost
1						($)
2	Metering Point Charge	25		$137.00		41,100
3	Substation Charge	25		$3,814.76		1,144,428
4	**Rate E1**					
5	Demand Charge [3]	2,194,036.0	kW	$7.58	/kW	16,630,793
6	Power Factor Penalty					11,301
7	Energy Charges					
8	On-Peak	515,341,871	kWh	$0.04891	/kWh	25,204,340
9	Off-Peak	484,561,322	kWh	$0.04836	/kWh	23,432,901
10				Total Energy Charges		48,637,241
11	Fuel Adjustment Charge	999,903,193	kWh	($0.00681)	/kWh	(6,813,402)
12						
13	Environmental Surcharge			8.93%		5,326,601
14				Total Rate E		64,978,062
15						
16	**Rate B**					
17	Minimum Demand	202,165.0	kW	$6.81	/kW	1,376,744
18	Excess Demand	8,704.0	kW	$9.47	/kW	82,427
19	Total Demand [3]	210,869.0	kW			1,459,171
20	Interuptible Demand - Firm	82,383.0	kW	$2.50	/kW	206,047
21	Interuptible Demand - Discount	3,810.0	kW	$0.00		-
22	Energy Charges	183,971,607	kWh	$0.04677	/kWh	8,604,720
23	Fuel Adjustment Charge	183,971,607	kWh	($0.006412)	/kWh	(1,179,617)
24	Environmental Surcharge			9.19%		816,786
25				Total Rate B		9,907,107
26						
27	**Special Contracts**					
28	**Gallatin**					
29	Firm Demand	180,000.0	kW	$6.63	/kW	1,193,400
30	10-Min Intter. Demand	1,426,898.0	kW	$1.03	/kW	1,469,705
31	90-Min Interr. Demand	99,629.0	kW	$2.43	/kW	242,098
32	Total Demand Charge	1,706,527.0				2,905,203
33	On-Peak Energy	211,869,199.0	kWh	$0.04713	/kWh	9,984,972
34	Off-Peak Energy	581,794,340.0	kWh	$0.04384	/kWh	25,508,191
35	Min. Energy On-Peak	18,804,206.0	kWh	$0.00815	/kWh	153,196
36	Min Energy Off-Peak	46,058,402.0	kWh	$0.00604	/kWh	278,406
37	Buy-Thru Chg, Cr On-Pk					113,084
38	Buy-Thru Chg, Cr Off-Pk					10,798
39	Energy Charge					36,048,647
40	Load Following Charge					325,000
41	FAC Charge	858,526,147.0	kWh	($0.00726)	/kWh	(6,233,618)
42	Environ. Surchg			8.03%		2,652,202
43				Total Gallatin		35,697,434
44						
45	**Total Test Year Purchased Power Cost**	2,042,400,947	kWh	$0.05414	/kWh	$110,582,602

[1] Billing units based on budget 2009

[2] Purchased Power Rates are the 2010 projected rates for East Kentucky Power Cooperative.

[3] Usage remains similar to 2009 usage.

Determination of Revenue Requirements - Summary
TIER Method

(a)	(b)	(c)	(d)
			Pro Forma Test Year
Line No.	**Description**	**2009 Actual**	**Present Rates**
Financial Results From Rates		($)	($)
1	Total Revenue [1]	141,746,616	142,770,898
2	Operating Expense [1]	140,319,392	140,900,547
3	Net Operating Income [2]	1,427,224	1,870,351
4	Non-Operating Income [3]	105,017	105,017
5	Income (Loss) from Equity Investments [3]	-	-
6	Other Capital Credits [3]	244,923	244,923
7	G&T Capital Credits [3]	3,551,381	3,551,381
8	Total Margin [4]	5,328,545	5,771,672
9	Rate of Return [5]	4.49%	4.82%
10	Operating TIER [6]	1.31	1.41
11	Modified TIER [7]	1.39	1.49
12	TIER [8]	2.17	2.26
Required Increase/(Decrease) --Modified TIER Objective			
13	Operating Expenses (excluding interest) [1]	135,754,418	136,335,573
14	Margin Requirements		
15	Interest Expense [3]	4,564,974	4,564,974
16	Target Modified TIER [9]	2.00	2.00
17	Total Margin Required (before interest) [10]	9,129,948	9,129,948
18	Less: Non-Operating Income [3]	105,017	105,017
19	Less: Income (Loss) from Equity Investments [3]	-	-
20	Less: Other Capital Credits [3]	244,923	244,923
21	Net Operating Income Required [11]	4,215,034	4,215,034
22	Total Revenue Requirements [12]	144,534,426	145,115,581
23	Revenue From Present Rates		
24	Tariff Revenue [1]	139,872,447	140,896,729
25	Other Operating Revenue [1]	1,874,169	1,874,169
26	Total Revenue [13]	141,746,616	142,770,898
27	Required Increase/(Decrease) [14]	2,787,810	2,344,683
28	Percent Increase/(Decrease) [15]	1.99	1.66

[1] See Exhibit 2.
[2] Line 1 minus Line 2.
[3] From year end Form 7.
[4] Sum of Lines 3 through 7
[5] Line 3 divided by Line 29 (on page 2).
[6] Sum of Lines 3 and 15 divided by Line 15
[7] Sum of Lines 3, 4, 5, and 15 divided by Line 15
[8] Sum of Lines 7 and 15 divided by Line 15
[9] As determined by Owen Electric Cooperative Inc..
[10] Line 15 times Line 16.
[11] Line 17 minus Lines 15 and 18 through 20.
[12] Line 13 plus Lines 15 and 21.
[13] Line 24 plus Line 25.
[14] Line 22 minus Line 26.
[15] Line 27 divided by Line 24.

Determination of Revenue Requirements Summary
Rate of Return Method
(Continued)

(a) Line No.	(b) Description	(c) 2009 Actual	(d) Pro Forma Test Year Present Rates
Required Increase (Decrease) --ROR Objective		($)	($)
29	Operating Expense (excluding interest) [1]	135,754,418	136,335,573
30	Margin Requirements		
31	Rate Base [2]	135,661,826	135,661,826
32	Rate of Return [3]	6.09%	6.09%
33	Required Return [4]	8,261,522	8,261,522
34	Less: Non-Operating Income [5]	105,017	105,017
35	Net Operating Income Required [6]	8,156,505	8,156,505
36	Total Revenue Requirements [7]	143,910,922	144,492,078
37	Revenue Present Rates		
38	Tariff Revenue [1]	139,872,447	140,896,729
39	Other Operating Revenue [1]	1,874,169	1,874,169
40	Total Revenue [8]	141,746,616	142,770,898
41	Required Increase (Decrease) [9]	2,164,306	1,721,179
42	Percent Increase (Decrease) [10]	1.55	1.22

[1] See Exhibit 3, Page 1.
[2] See Exhibit 3, page 3.
[3] See Exhibit 3, page 5.
[4] Line 31 times Line 32.
[5] See Exhibit 3, Page 1, Line 4 plus Line 5.
[6] Line 33 minus Line 35.
[7] Line 29 plus Line 35.
[8] Line 38 plus Line 39.
[9] Line 36 minus Line 40.
[10] Line 41 divided by Line 38.

Schedule A
Rate Base

(a) Line No.	(b) Description	(c) Pro Forma Test Year
		($)
1	Utility Plant in Service [1]	204,255,817
2	Construction Work in Progress [1]	3,617,437
3	Less: Accumulated Provision for Deprec. [1]	75,981,487
4	Net Plant [1]	131,891,767
5	Materials & Supplies - Electric [2]	994,264
6	Prepayments [2]	475,528
7	Working Capital [3]	5,003,244
8	Subtotal	6,473,036
9	Less: Consumer Deposits [1]	2,702,977
10	**Total Rate Base**	135,661,826

1 December 31, 2009, Form 7 amount.
2 13 - Month Average. See Schedule B.
3 See Schedule B.

Schedule B
Rate Base Calculations
Materials & Supplies - Electric Prepayments

(a) Line No.	(b) Month		(c) Materials & Supplies Electric	(d) Prepayments
			($)	($)
1	Dec	2008	1,026,017	379,544
2	Jan	2009	1,051,392	713,270
3	Feb	2009	1,027,161	632,468
4	Mar	2009	989,029	544,589
5	Apr	2009	999,315	456,107
6	May	2009	928,362	390,187
7	Jun	2009	974,984	371,111
8	Jul	2009	961,130	504,117
9	Aug	2009	993,383	513,674
10	Sep	2009	1,024,777	434,575
11	Oct	2009	1,022,309	366,835
12	Nov	2009	956,292	335,363
13	Dec	2009	971,283	540,028
14	**Total**		12,925,435	6,181,867
15	**13 - Month Average**		994,264	475,528

Schedule B
Rate Base Calculations
Working Capital
(Continued)

(a) Line No.	(b) Description	(c) Weight Factor	(d) Pro Forma Test Year Total Amount	(e) Pro Forma Test Year Weighted Amount
			($)	($)
1	Purchased Power	10/365	110,582,602	3,029,660
2	Other O&M Exp.			
3	Dist. Oper.		5,379,575	
4	Dist. Main.		3,863,514	
5	Cons. Acct.		3,427,328	
6	Cons. Serv.		559,353	
7	Sales		-	
8	Admin. & Gen.		2,778,189	
9	**Subtotal**	45/365	16,007,958	1,973,584
10	**Total Working Capital**			5,003,244

Schedule C
Composite Cost of Capital
and Rate of Return

(a) Line No.	(b) Description	(c) Interest Rate	(d) Estimated Balance	(e) Annualized Interest Expense [1]	(f) Actual Percent of Total	(g) Cost of Capital	(h) Weighted Cost of Capital
	Long Term Debt	(%)	($)	($)	(%)	(%)	(%)
1	RUS	5.38%	1,396,119	75,041			
2	RUS	4.37%	1,292,753	56,493			
3	RUS	4.46%	12,952,131	577,665			
4	RUS	4.19%	6,972,821	292,161			
5	RUS	4.44%	8,921,842	396,130			
6	RUS	3.62%	1,443,033	52,238			
7	RUS	0.50%	1,450,461	7,252			
8	CFC [2]	5.64%	24,172,174	1,363,211			
9	FFB [3]	5.40%	35,600,223	1,921,593			
10	Total Long Term Debt		94,201,556	4,741,785	61.8	5.03	3.11
11	Equity [4]		58,254,456		38.2	7.80 [5]	2.98
12	Total LT Debt and Equity		152,456,012		100.0		
13	**Required Rate of Return**						6.09

[1] The Annualized Interest Expense is based on the Estimated Loan Balance multiplied by the loan interest rate.

[2] Represents Total CFC Loans and a weighted average interest rate.

[3] Represents Total FFB Loans and a weighted average interest rate.

[4] Data taken from RUS Form 7 for December 31, 2009.

[5] See Schedule E.

Schedule D
Growth Rate Calculation

(a) Line No.	(b) Year	(c) Net Plant [1] ($)
1	2004	105,007,231
2	2005	109,777,890
3	2006	118,455,515
4	2007	126,414,703
5	2008	129,616,048
6	2009	131,891,767

The mean growth rate in Net Plant is estimated to be:

2004-2009 = 4.66%

[1] Net Plant figures are from the utility's RUS Form 7 for the years listed.

Schedule E
Cost of Equity Capital

1. Criteria & Cooperative Policy

a. Rotate capital credits on a 20 year cycle based on the Cooperative's policy.

b. Annual growth rate = 4.66%
(See Schedule D)

2. Calculation of Return on Equity Capital

$$R = \frac{(1+g)^{n+1} - (1+g)^{n}}{(1+g)^{n} - 1}$$

WHERE: R = rate of return on equity
n = number of years in rotation period
g = growth rate

$$R = \frac{1.0466^{21} - 1.0466^{20}}{1.0466^{20} - 1} = 7.80\%$$

Rebecca Witt

From: Laslie, Jeffrey [lasliej@powersystem.org]
Sent: Wednesday, May 12, 2010 12:10 PM
To: Rebecca Witt; Cobb, Kathryn
Cc: Mike Cobb; Mark Stallons
Subject: RE: Information for COS

Becky,

Thank you very much for the update and for reviewing the revenue requirements data.

Since Gallatin is under special contract and we will not include it in the cost of service study, we used units provided to us by EKPC. This will not affect the study results for Owen.

Differences between recorded (Form 7) revenues and those reported for a rate study are normal. Indeed, Owen's revenue data is very close in comparison to most rate studies we work on. For the cost of service study, we will use pro forma revenue as shown in column h and calculated in part II of the schedule A, so the difference will not impact the study results.

Thanks again for reviewing the data and all the time you and the other Owen folks have spent on the project.

Jeff

Jeff Laslie
Power System Engineering, Inc.
Phone: 317-322-5906
Fax: 317-322-5924
Cell: 317-696-0820
lasliej@powersystem.org

From: Rebecca Witt [mailto:rwitt@owenelectric.com]
Sent: Tuesday, May 11, 2010 4:43 PM
To: Laslie, Jeffrey; Cobb, Kathryn
Cc: Mike Cobb; Mark Stallons
Subject: Information for COS

Jeff & Kathy,

Attached is the final (I promise) spreadsheet that we are using for EKPC's rate filing. We did find additional errors in the spreadsheets relating to the outdoor lighting data, so those numbers changed.

I have looked at the revenue requirement documentation that you sent and, except for the changes that will occur as a result of the attached data, I only had the following comments:

For Gallatin Steel, I had different KWH minimum billing data. (18,784,206 On-Peak and 52,058,402 Off-Peak). My total actual energy sales for 2009 was 864,506,147. Not a huge difference, but you might want to check. You may have been using some other information, but that is what I calculated from the bills.

On Exhibit 2, Schedule A, I could not tie back to your Avg No Consumer numbers in column c and the actual revenues in column g. The actual revenue total used elsewhere is $139,872,448, and I believe that is correct, as opposed to the $139,806,919 listed on Sch A. Again, not a very big difference, just couldn't get back to it.

Otherwise, all looked good. Everything was easy to trace and made sense. Thanks,

Becky

Rebecca Witt
SR VP Corporate Services
Owen Electric Cooperative, Inc.
502-563-3544

Rebecca Witt

From: Laslie, Jeffrey [lasliej@powersystem.org]
Sent: Thursday, May 27, 2010 10:39 AM
To: Mark Stallons; Rebecca Witt
Cc: Macke, Rich; Isaac Scott; cobbk@powersystem.org; Cuellar, Marilyn
Subject: EKPC Rate Study - Cost of Service Results
Attachments: Owen Exhibit 2 5-25-2010.pdf; JCL-Stallons-5-27-10.pdf; Owen Exhibit 4 5-27-2010.pdf; Owen Exhibit 3 5-25-2010.pdf

Dear Mark,

Please see the attached letter and exhibits regarding the EKPC rate study.

Thanks,
Jeff

Jeff Laslie
Power System Engineering, Inc.
Phone: 317-322-5906
Fax: 317-322-5924
Cell: 317-696-0820
lasliej@powersystem.org

Via e-mail

May 27, 2010

Mr. Mark Stallons
President and CEO
Owen Electric Cooperative
P.O. Box 400
Owenton, KY 40359-0400

Subject: EKPC Study - Cost of Service Analysis - Summary

Dear Mark:

Enclosed are the following exhibits from the Wholesale & Retail Rates Feasibility Study for your review:

- Exhibit 2 - Statement of Operations - Present Rates (Revised);
- Exhibit 3 - Revenue Requirements Analysis (Revised); and
- Exhibit 4 - Cost of Service Analysis - Summary
  This presents the three summary tables from the Cost of Service analysis (COS). The full analysis will be available on the Box.net site for your review.

Revisions to Exhibits 2 and 3

The revisions to Exhibit 2 were the result of minor corrections to the revenue data used in the study that were received subsequent to PSE's May 7 letter summarizing the results of the revenue requirements segment of the study. In total, these revisions reduced pro forma revenues $157,000 and increased the required rate increase necessary to achieve a 2 TIER an equal amount or from 1.66% to 1.78% of total sales of electricity. Note that the difference between the 1.78% increase and the 2.4% increase shown in the Cost of Service results below is due to the exclusion of contract sales from the Cost of Service analysis.

Exhibit 4 - Cost of Service Analysis - Summary

The summary pages from the Cost of Service (COS) analysis are included in the attached Exhibit 4. This COS has been prepared under the existing EKPC wholesale rate structure.

Page 1 of the COS summarizes the present rate revenue, revenue requirements and resulting required increase or (decrease) to align rates exactly with the cost of providing service for each of the rate classes. Note that line 6 of this page distributes the non-rate schedule operating revenue to each class according to the revenue under present rates as shown on line 5.

2010 Class Cost of Service
Summary -- Present Rates

Rate Class	Class Revenue	Cost of Service	Difference	As Percent[1]
	($)	($)	($)	
Schedule I Farm And Home	72,129,401	77,799,611	5,670,210	8.0%
Schedule I-A Residential Marketing	1,420	2,274	854	61.2%
Schedule I(2) Small Commercial	4,613,575	4,665,078	51,503	1.1%
Schedule II Large Power	15,476,680	13,230,991	(2,245,689)	(14.8%)
Schedule XI Large Industrial LPB1	4,910,160	4,210,559	(699,600)	(14.5%)
Schedule XIII Large Industrial LPB2	6,711,949	6,576,399	(135,550)	(2.1%)
Schedule XIV Large Industrial LPB	907,886	683,463	(224,423)	(25.2%)
Schedule 2-A Large Power TOD	316,586	282,775	(33,812)	(10.9%)
Outdoor Lighting Service	1,564,760	1,682,869	118,109	7.7%
Total	106,632,417	109,134,019	2,501,602	2.4%

Page 2 of this exhibit categorizes the total class revenue requirements into Power Supply, Transmission and Distribution service functions. Furthermore, each of these major service functions may include cost components of Direct, Consumer, Capacity and Energy. The substantial detail associated with this summary page is not included with this letter for the sake of simplicity.

Page 3 uses the information detailed on page 2 to develop a per unit cost using either customers or kWh as a basis. PSE views the COS results as providing an indication of where rates should generally be and as providing useful information regarding which rate classes and/or components should receive potential increases/decreases.

1/ The "As Percent" column in the Cost of Service Summary table is calculated using rate revenues only to show the average rate increase or decrease necessary to align rates with cost of service

Please review the enclosed and feel free to call me at (317) 322-5906 if you should have any questions.

Very truly yours,

Jeffrey C. Laslie
Senior Financial Analyst

KY0591018/mmc

cc: Becky Witt, Owen
Isaac Scott, EKPC
Rich Macke, PSE

Enclosures

Statement of Operations
Present Rates
Test Year - 2009

(a) Line No.	(b) Description	(c) 2009 Actual	(d) Pro Forma Test Year
1	**Operating Revenue**	($)	($)
2	Rate Schedule Revenue	139,872,447 [1]	140,739,813 [1]
3	Other Operating Revenue	1,874,169	1,874,169
4	**Total Operating Revenue**	141,746,616	142,613,982
5	**Operating Expenses**		
6	Purchased Power Expense	110,001,447	110,582,602 [2]
7	Transmission - O&M Expense	-	-
8	Distribution - Operation Expense	5,379,575	5,379,575
9	Distribution - Maintenance Expense	3,863,514	3,863,514
10	Consumer Accounting Expense	3,427,328	3,427,328
11	Consumer Service & Information Expense	559,353	559,353
12	Sales Expense	-	-
13	Administrative & General Expense	2,778,189	2,778,189
14	Depreciation & Amortization Expense	9,253,930	9,253,930
15	Property Tax Expense	-	-
16	Other Tax Expense	138,361	138,361
17	Long-Term Interest Expense	4,564,974	4,564,974
18	Other Interest Expense	282,323	282,323
19	Other Deductions	70,399	70,399
20	**Total Operating Expenses**	140,319,392	140,900,547
21	**Operating Margins**	1,427,224	1,713,435
22	**Operating TIER**	1.31	1.38
23	Plus: Non-Operating Margins - Interest	96,038	96,038
24	Plus: Income (loss) from Equity Investments	-	-
25	Plus: Non-Operating Margins - Other	8,980	8,980
26	Plus: Other Capital Credits	244,923	244,923
27	**Margins Before G&T Capital Credits**	1,777,164	2,063,375
28	**Modified TIER**	1.39	1.45
29	Plus: G&T Capital Credits	3,551,381	3,551,381
30	**Patronage Capital or Margins**	5,328,545	5,614,756
31	**TIER**	2.17	2.23

[1] See Exhibit 2, Schedule A for the Pro Forma Test Year revenue.
[2] See Exhibit 2, Schedule B for the Pro Forma Test Year purchased power expense.

Schedule A
Summary of Consumers, Energy Sales, and Revenue Under Present Rates

I. Consumer and Sales Data for the Pro Forma Test Year

(a) Line No.	(b) Description	(c) Avg. No. Cons. [1]	(d) Energy Sales [1]	(e) Billing Demand [1] Non-Coinc.	(f) Coinc.	(g) Actual Revenue [1]	(h) Pro Forma Revenue [2]
			(kWh)	(kW)	(kW)	($)	($)
1	Schedules I: Farm and Home	54,076	710,449,061	NA	NA	70,124,670	70,861,656
2	Schedules I-A: Residential Marketing	8	27,641	NA	NA	1,527	1,395
3	Schedule I: Small Commercial	2,294	46,652,046	NA	NA	4,508,357	4,532,487
4	Schedule II: Large Power	250	177,917,564	557,060.0	NA	15,411,323	15,204,662
5	Schedule 5: Renewable Resource Power			NA	NA	-	
6	Schedule III: Security Lights	9,345	6,372,258	NA	NA	829,843	996,930
7	Schedule XI: Large Industrial LPB1	9	67,594,969	146,008.0	NA	4,947,049	4,823,859
8	Schedule XIII: Large Industrial Rate LPB2	2	109,933,836	188,885.0	NA	6,235,632	6,593,980
9	Schedule XIV: Large Industrial Rate LPB	4	10,883,375	28,527.0	NA	961,330	891,929
10	Schedule I OLS: Outdoor Lighting Service	3,327	1,692,936	NA	NA	416,888	457,765
11	Schedule II SOLS: SpecialOutdoor Lighting	480	228,904	NA	NA	62,465	82,563
12	Schedule III SOLS: SpecialOutdoor Lighting			NA	NA		-
13	Schedule 2-A: Large Power - Time of Day	9	3,633,704	NA	NA	300,985	311,022
14	Gallatin Contract	1	858,526,147	1,706,527.0	NA	35,984,650	35,981,564
15	**Total** [3]	56,645	1,993,912,441	2,627,007.0	-	139,784,719	140,739,813

[1] As reported by the Cooperative for 2009.

[2] See Schedule A, pages 3 - 5.

[3] The total number of consumers excludes number of Outdoor Lighting Service and Residential Marketing.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
Schedules I: Farm and Home				
Customer Charge	54,076	/month	$10.87	7,053,630
Energy Charge	710,449,061	/kWh	$0.09126	64,835,581
Fuel Charge	710,449,061	/kWh	($0.00719)	(5,111,624)
Environmental Surcharge			6.1%	4,084,069
				70,861,656
Schedules I-A: Residential Marketing				
Energy Charge	27,641	/kWh	$0.05476	1,514
Fuel Charge	27,641	/kWh	($0.00719)	(199)
Environmental Surcharge			6.1%	80
				1,395
Schedule I: Small Commercial				
Customer Charge	2,294	/month	$12.83	353,184
Energy Charge	46,652,046	/kWh	$0.09118	4,253,734
Fuel Charge	46,652,046	/kWh	($0.00719)	(335,658)
Environmental Surcharge			6.1%	261,227
				4,532,487
Schedule II: Large Power				
Customer Charge	250	/month	$20.50	61,500
Energy Charge	177,917,564	/kWh	$0.06891	12,260,299
Demand Charge	557,060	/kW	$5.90	3,286,654
Fuel Charge	177,917,564	/kWh	($0.00719)	(1,280,103)
Environmental Surcharge			6.1%	876,312
				15,204,662
Schedule III: Security Lights				
120 Volts, where available	7,760	/month	$8.46	787,795
With 1 Pole Added	1,495	/month	$10.20	182,988
With 2 Pole Added	83	/month	$11.94	11,892
With 3 Pole Added	7	/month	$13.68	1,149
With 4 Pole Added	-	/month	$15.43	-
Transformer Charge	186	/month	$0.67	1,495
Fuel Charge	6,372,258	/kWh	($0.00719)	(45,848)
Environmental Surcharge			6.1%	57,457
	9,345			996,930
Schedule XI: Large Industrial LPB1				
Customer Charge	9	/month	$1,464.04	162,508
Energy Charge - 425 Hrs per kW	61,090,580	/kWh	$0.05446	3,326,993
Energy Charge - Over 425 Hrs per kW	6,504,389	/kWh	$0.05038	327,691
Demand Charge - Contract Demand	146,008	/kW	$6.81	994,314
Demand Charge - kW > Contract Demand	12,194	/kW	$9.47	115,477
Fuel Charge	67,594,969	/kWh	($0.00626)	(423,201)
Environmental Surcharge			7.1%	320,076
				4,823,859

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
Schedule XIII: Large Industrial Rate LPB2				
Customer Charge	2	/month	$2,927.05	70,249
Energy Charge - 425 Hrs per kW	83,036,690	/kWh	$0.04971	4,127,754
Energy Charge - Over 425 Hrs per kW	26,897,146	/kWh	$0.04813	1,294,560
Demand Charge - Contract Demand	195,900	/kW	$6.81	1,334,079
Demand Charge - kW > Contract Demand	1,910	/kW	$9.47	18,088
Fuel Charge	109,933,836	/kWh	($0.00626)	(688,277)
Environmental Surcharge			7.1%	437,528
				6,593,980
Schedule XIV: Large Industrial Rate LPB				
Customer Charge	4	/month	$1,464.00	70,272
Energy Charge	10,883,375	/kWh	$0.05600	609,469
Demand Charge - Contract Demand	28,527	/kW	$6.81	194,269
Demand Charge - kW > Contract Demand	2,838	/kW	$9.47	26,876
Fuel Charge	10,883,375	/kWh	($0.00626)	(68,139)
Environmental Surcharge			7.1%	59,182
				891,929
Schedule I OLS: Outdoor Lighting Service				
100 Watt HPS Area	3,138	/month	$10.12	381,079
Cobrahead Lighting				
100 Watt HPS	25	/month	$13.05	3,915
250 Watt HPS	11	/month	$17.90	2,363
400 Watt HPS	20	/month	$22.63	5,431
Directional Lighting				
100 Watt HPS	27	/month	$12.24	3,966
250 Watt HPS	27	/month	$15.25	4,941
400 Watt HPS	77	/month	$19.73	18,231
Pole Charges	420	/month	$4.69	23,638
Fuel Charge	1,692,936	/kWh	($0.00719)	(12,181)
Environmental Surcharge			6.12%	26,383
				457,765
Schedule II SOLS: SpecialOutdoor Lighting				
Traditional Light W/ Fiberglass Pole	299	/month	$12.90	46,285
Holophane Light W/ Fiberglass Pole	181	/month	$15.27	33,166
Fuel Charge	228,904	/kWh	($0.00719)	(1,647)
Environmental Surcharge			6.12%	4,758
				82,563
Schedule III SOLS: SpecialOutdoor Lighting				
Facilities Charge (1.75 x total investment)		/month	$0.00	-
Energy Charge		/kWh	$0.063902	-
Fuel Charge		/kWh	($0.007195)	-
Environmental Surcharge			6.12%	0
				-
Schedule 2-A: Large Power - Time of Day				
Customer Charge	9	/month	$59.00	6,608
Energy Charge - On Peak	1,836,960	/kWh	$0.105948	194,622
Energy Charge - Off Peak	1,796,744	/kWh	$0.064171	115,299
Fuel Charge	3,633,704	/kWh	($0.0071949)	(26,144)
Environmental Surcharge			7.11%	20,637
				311,022

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Special Contracts				
Gallatin				
Firm Demand	180,000.0	/kW	$6.63	1,193,400
10-Min Intter. Demand	1,426,898.0	/kW	$1.03	1,469,705
90-Min Interr. Demand	99,629.0	/kW	$2.43	242,098
Total Demand Charge	1,706,527.0			2,905,203
On-Peak Energy	211,869,199.0	/kWh	$0.04713	9,984,972
Off-Peak Energy	581,794,340.0	/kWh	$0.04384	25,508,191
Min. Energy On-Peak	18,804,206.0	/kWh	$0.00815	153,196
Min Energy Off-Peak	46,058,402.0	/kWh	$0.00604	278,406
Buy-Thru Chg, Cr On-Pk				113,084
Buy-Thru Chg, Cr Off-Pk				10,798
Energy Charge				36,048,647
Load Following Charge				325,000
FAC Charge	858,526,147.0	/kWh	($0.00726)	(6,233,618)
Distribution Demand Charge	1,706,527.0		$0.03750	63,995
Distribution Energy Charge	858,526,147.0	/kWh	$0.00029	244,680
Environmental Surcharge			7.95%	2,627,657
				35,981,564

Schedule B
Estimate of Pro Forma Test Year Purchased Power Expense

(a) Line No.	(b) Description	(c) Units [1]		(d) Rate [2]		(e) Cost
1						($)
2	Metering Point Charge	25		$137.00		41,100
3	Substation Charge	25		$3,814.76		1,144,428
4	**Rate E1**					
5	Demand Charge [3]	2,194,036.0	kW	$7.58	/kW	16,630,793
6	Power Factor Penalty					11,301
7	Energy Charges					
8	On-Peak	515,341,871	kWh	$0.04891	/kWh	25,204,340
9	Off-Peak	484,561,322	kWh	$0.04836	/kWh	23,432,901
10				Total Energy Charges		48,637,241
11	Fuel Adjustment Charge	999,903,193	kWh	($0.00681)	/kWh	(6,813,402)
12						
13	Environmental Surcharge			8.93%		5,326,601
14				Total Rate E		64,978,062
15						
16	**Rate B**					
17	Minimum Demand	202,165.0	kW	$6.81	/kW	1,376,744
18	Excess Demand	8,704.0	kW	$9.47	/kW	82,427
19	Total Demand [3]	210,869.0	kW			1,459,171
20	Interuptible Demand - Firm	82,383.0	kW	$2.50	/kW	206,047
21	Interuptible Demand - Discount	3,810.0	kW	$0.00		-
22	Energy Charges	183,971,607	kWh	$0.04677	/kWh	8,604,720
23	Fuel Adjustment Charge	183,971,607	kWh	($0.006412)	/kWh	(1,179,617)
24	Environmental Surcharge			9.19%		816,786
25				Total Rate B		9,907,107
26						
27	**Special Contracts**					
28	**Gallatin**					
29	Firm Demand	180,000.0	kW	$6.63	/kW	1,193,400
30	10-Min Intter. Demand	1,426,898.0	kW	$1.03	/kW	1,469,705
31	90-Min Interr. Demand	99,629.0	kW	$2.43	/kW	242,098
32	Total Demand Charge	1,706,527.0				2,905,203
33	On-Peak Energy	211,869,199.0	kWh	$0.04713	/kWh	9,984,972
34	Off-Peak Energy	581,794,340.0	kWh	$0.04384	/kWh	25,508,191
35	Min. Energy On-Peak	18,804,206.0	kWh	$0.00815	/kWh	153,196
36	Min Energy Off-Peak	46,058,402.0	kWh	$0.00604	/kWh	278,406
37	Buy-Thru Chg, Cr On-Pk					113,084
38	Buy-Thru Chg, Cr Off-Pk					10,798
39	Energy Charge					36,048,647
40	Load Following Charge					325,000
41	FAC Charge	858,526,147.0	kWh	($0.00726)	/kWh	(6,233,618)
42	Environ. Surchg			8.03%		2,652,202
43				Total Gallatin		35,697,434
44						
45	**Total Test Year Purchased Power Cost**	2,042,400,947	kWh	$0.05414	/kWh	$110,582,602

1 Billing units based on budget 2009

2 Purchased Power Rates are the 2010 projected rates for East Kentucky Power Cooperative.

3 Usage remains similar to 2009 usage.

Determination of Revenue Requirements - Summary
TIER Method

(a) Line No.	(b) Description	(c) 2009 Actual	(d) Pro Forma Test Year Present Rates
	Financial Results From Rates	($)	($)
1	Total Revenue [1]	141,746,616	142,613,982
2	Operating Expense [1]	140,319,392	140,900,547
3	Net Operating Income [2]	1,427,224	1,713,435
4	Non-Operating Income [3]	105,017	105,017
5	Income (Loss) from Equity Investments [3]	-	-
6	Other Capital Credits [3]	244,923	244,923
7	G&T Capital Credits [3]	3,551,381	3,551,381
8	Total Margin [4]	5,328,545	5,614,756
9	Rate of Return [5]	4.49%	4.71%
10	Operating TIER [6]	1.31	1.38
11	Modified TIER [7]	1.39	1.45
12	TIER [8]	2.17	2.23
	Required Increase/(Decrease) --Modified TIER Objective		
13	Operating Expenses (excluding interest) [1]	135,754,418	136,335,573
14	Margin Requirements		
15	Interest Expense [3]	4,564,974	4,564,974
16	Target Modified TIER [9]	2.00	2.00
17	Total Margin Required (before interest) [10]	9,129,948	9,129,948
18	Less: Non-Operating Income [3]	105,017	105,017
19	Less: Income (Loss) from Equity Investments [3]	-	-
20	Less: Other Capital Credits [3]	244,923	244,923
21	Net Operating Income Required [11]	4,215,034	4,215,034
22	Total Revenue Requirements [12]	144,534,426	145,115,581
23	Revenue From Present Rates		
24	Tariff Revenue [1]	139,872,447	140,739,813
25	Other Operating Revenue [1]	1,874,169	1,874,169
26	Total Revenue [13]	141,746,616	142,613,982
27	Required Increase/(Decrease) [14]	2,787,810	2,501,599
28	Percent Increase/(Decrease) [15]	1.99	1.78

[1] See Exhibit 2.
[2] Line 1 minus Line 2.
[3] From year end Form 7.
[4] Sum of Lines 3 through 7
[5] Line 3 divided by Line 29 (on page 2).
[6] Sum of Lines 3 and 15 divided by Line 15
[7] Sum of Lines 3, 4, 5, and 15 divided by Line 15
[8] Sum of Lines 7 and 15 divided by Line 15
[9] As determined by Owen Electric Cooperative Inc..
[10] Line 15 times Line 16.
[11] Line 17 minus Lines 15 and 18 through 20.
[12] Line 13 plus Lines 15 and 21.
[13] Line 24 plus Line 25.
[14] Line 22 minus Line 26.
[15] Line 27 divided by Line 24.

Determination of Revenue Requirements Summary
Rate of Return Method
(Continued)

(a)	(b)	(c)	(d)
			Pro Forma Test Year
Line No.	**Description**	**2009 Actual**	**Present Rates**
	Required Increase (Decrease) --ROR Objective	($)	($)
29	Operating Expense (excluding interest) [1]	135,754,418	136,335,573
30	Margin Requirements		
31	Rate Base [2]	135,661,826	135,661,826
32	Rate of Return [3]	6.09%	6.09%
33	Required Return [4]	8,261,522	8,261,522
34	Less: Non-Operating Income [5]	105,017	105,017
35	Net Operating Income Required [6]	8,156,505	8,156,505
36	Total Revenue Requirements [7]	143,910,922	144,492,078
37	Revenue Present Rates		
38	Tariff Revenue [1]	139,872,447	140,739,813
39	Other Operating Revenue [1]	1,874,169	1,874,169
40	Total Revenue [8]	141,746,616	142,613,982
41	Required Increase (Decrease) [9]	2,164,306	1,878,095
42	Percent Increase (Decrease) [10]	1.55	1.33

1 See Exhibit 3, Page 1.
2 See Exhibit 3, page 3.
3 See Exhibit 3, page 5.
4 Line 31 times Line 32.
5 See Exhibit 3, Page 1, Line 4 plus Line 5.
6 Line 33 minus Line 35.
7 Line 29 plus Line 35.
8 Line 38 plus Line 39.
9 Line 36 minus Line 40.
10 Line 41 divided by Line 38.

Schedule A
Rate Base

(a) Line No.	(b) Description	(c) Pro Forma Test Year
		($)
1	Utility Plant in Service [1]	204,255,817
2	Construction Work in Progress [1]	3,617,437
3	Less: Accumulated Provision for Deprec. [1]	75,981,487
4	Net Plant [1]	131,891,767
5	Materials & Supplies - Electric [2]	994,264
6	Prepayments [2]	475,528
7	Working Capital [3]	5,003,244
8	Subtotal	6,473,036
9	Less: Consumer Deposits [1]	2,702,977
10	**Total Rate Base**	135,661,826

[1] December 31, 2009, Form 7 amount.

[2] 13 - Month Average. See Schedule B.

[3] See Schedule B.

Schedule B
Rate Base Calculations
Materials & Supplies - Electric Prepayments

(a) Line No.	(b) Month		(c) Materials & Supplies Electric	(d) Prepayments
			($)	($)
1	Dec	2008	1,026,017	379,544
2	Jan	2009	1,051,392	713,270
3	Feb	2009	1,027,161	632,468
4	Mar	2009	989,029	544,589
5	Apr	2009	999,315	456,107
6	May	2009	928,362	390,187
7	Jun	2009	974,984	371,111
8	Jul	2009	961,130	504,117
9	Aug	2009	993,383	513,674
10	Sep	2009	1,024,777	434,575
11	Oct	2009	1,022,309	366,835
12	Nov	2009	956,292	335,363
13	Dec	2009	971,283	540,028
14	**Total**		12,925,435	6,181,867
15	**13 - Month Average**		994,264	475,528

Schedule B
Rate Base Calculations
Working Capital
(Continued)

(a) Line No.	(b) Description	(c) Weight Factor	(d) Pro Forma Test Year Total Amount	(e) Pro Forma Test Year Weighted Amount
			($)	($)
1	Purchased Power	10/365	110,582,602	3,029,660
2	Other O&M Exp.			
3	Dist. Oper.		5,379,575	
4	Dist. Main.		3,863,514	
5	Cons. Acct.		3,427,328	
6	Cons. Serv.		559,353	
7	Sales		-	
8	Admin. & Gen.		2,778,189	
9	**Subtotal**	45/365	16,007,958	1,973,584
10	**Total Working Capital**			5,003,244

Schedule C
Composite Cost of Capital
and Rate of Return

(a) Line No.	(b) Description	(c) Interest Rate	(d) Estimated Balance	(e) Annualized Interest Expense [1]	(f) Actual Percent of Total	(g) Cost of Capital	(h) Weighted Cost of Capital
	Long Term Debt	(%)	($)	($)	(%)	(%)	(%)
1	RUS	5.38%	1,396,119	75,041			
2	RUS	4.37%	1,292,753	56,493			
3	RUS	4.46%	12,952,131	577,665			
4	RUS	4.19%	6,972,821	292,161			
5	RUS	4.44%	8,921,842	396,130			
6	RUS	3.62%	1,443,033	52,238			
7	RUS	0.50%	1,450,461	7,252			
8	CFC [2]	5.64%	24,172,174	1,363,211			
9	FFB [3]	5.40%	35,600,223	1,921,593			
10	Total Long Term Debt		94,201,556	4,741,785			
11	Equity [4]		58,254,456				
12	Total LT Debt and Equity		152,456,012				
13	**Required Rate of Return**						

[1] The Annualized Interest Expense is based on the Estimated Loan Balance multiplied by the loan interest rate.
[2] Represents Total CFC Loans and a weighted average interest rate.
[3] Represents Total FFB Loans and a weighted average interest rate.
[4] Data taken from RUS Form 7 for December 31, 2009.
[5] See Schedule E.

61.8	5.03	3.11
38.2	7.80 [5]	2.98
100.0		
		6.09

Schedule D
Growth Rate Calculation

(a) Line No.	(b) Year	(c) Net Plant [1] ($)
1	2004	105,007,231
2	2005	109,777,890
3	2006	118,455,515
4	2007	126,414,703
5	2008	129,616,048
6	2009	131,891,767

The mean growth rate in Net Plant is estimated to be:

2004-2009 = 4.66%

[1] Net Plant figures are from the utility's RUS Form 7 for the years listed.

Schedule E
Cost of Equity Capital

1. Criteria & Cooperative Policy

a. Rotate capital credits on a 20 year cycle based on the Cooperative's policy.

b. Annual growth rate = 4.66%
(See Schedule D)

2. Calculation of Return on Equity Capital

$$R = \frac{(1+g)^{n+1} - (1+g)^{n}}{(1+g)^{n} - 1}$$

WHERE: R = rate of return on equity
n = number of years in rotation period
g = growth rate

$$R = \frac{1.0466^{21} - 1.0466^{20}}{1.0466^{20} - 1} = 7.80\%$$

Cost of Service Summary

Revenue Requirements Summary – BUNDLED

Line No.	Description	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
1	**Revenue Requirements**										
2	Revenue Requirements	109,134,019	77,799,611	2,274	4,665,078	13,230,991	4,210,559	6,576,399	683,463	282,775	1,682,869
3											
4	**Present Rates**										
5	Revenue-Present Rates	104,758,248	70,861,656	1,395	4,532,487	15,204,662	4,823,859	6,593,980	891,929	311,022	1,537,258
6	Revenue Credits	1,874,169	1,267,745	25	81,088	272,018	86,301	117,969	15,957	5,564	27,502
7		106,632,417	72,129,401	1,420	4,613,575	15,476,680	4,910,160	6,711,949	907,886	316,586	1,564,760
8											
9	Difference	2,501,602	5,670,210	854	51,503	(2,245,689)	(699,600)	(135,550)	(224,423)	(33,812)	118,109
10	As Percent	2.4%	8.0%	61.2%	1.1%	(14.8%)	(14.5%)	(2.1%)	(25.2%)	(10.9%)	7.7%

Cost of Service Summary
Class Allocation Summary -- BUNDLED

Line No.	Category	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
20	Power Supply										
21	Direct and Revenue Related										
22	Wholesale Cost	6,143,387	4,082,834	80	261,148	876,047	320,076	437,528	59,182	17,920	88,572
23	Allocated Cost	0	0	0	0	0	0	0	0	0	0
24	Subtotal	6,143,387	4,082,834	80	261,148	876,047	320,076	437,528	59,182	17,920	88,572
25	Capacity Related										
26	Wholesale Cost	18,307,312	13,485,459	0	686,089	2,311,820	669,020	865,485	130,713	46,914	111,811
27	Allocated Cost	0	0	0	0	0	0	0	0	0	0
28	Subtotal	18,307,312	13,485,459	0	686,089	2,311,820	669,020	865,485	130,713	46,914	111,811
29	Energy Related										
30	Wholesale Cost	49,248,942	31,370,303	1,170	2,067,973	7,874,849	2,626,200	4,417,142	381,761	160,832	348,712
31	Allocated Cost	0	0	0	0	0	0	0	0	0	0
32	Subtotal	49,248,942	31,370,303	1,170	2,067,973	7,874,849	2,626,200	4,417,142	381,761	160,832	348,712
33	Sub. Power Supply	73,699,641	48,938,596	1,250	3,015,211	11,062,716	3,615,296	5,720,156	571,656	225,667	549,094
34	Transmission										
35	Direct	0	0	0	0	0	0	0	0	0	0
36	Capacity	0	0	0	0	0	0	0	0	0	0
37	Energy	0	0	0	0	0	0	0	0	0	0
38	Allocated Cost	0	0	0	0	0	0	0	0	0	0
39	Sub. Transmission	0	0	0	0	0	0	0	0	0	0
40	Distribution										
41	Direct	775,651	0	0	0	0	0	0	0	0	775,651
42	Consumer	21,359,339	19,788,221	668	1,065,620	231,439	10,327	2,295	4,590	15,542	240,638
43	Capacity	13,299,387	9,072,794	356	584,248	1,936,836	584,937	853,948	107,218	41,566	117,486
44	Energy	0	0	0	0	0	0	0	0	0	0
45	Sub. Distribution	35,434,378	28,861,015	1,024	1,649,868	2,168,275	595,264	856,243	111,808	57,108	1,133,775
46											
47	**Total**	109,134,019	77,799,611	2,274	4,665,078	13,230,991	4,210,559	6,576,399	683,463	282,775	1,682,869

Cost of Service Summary
Rate Design Factors -- BUNDLED

Line No.	Category	Units	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
48	Costs Broken Down by Function											
49	Power Supply											
50	Direct and Revenue Related											
51	Wholesale Cost	¢/kWh	0.54	0.57	0.29	0.56	0.49	0.47	0.40	0.54	0.49	1.07
52	Allocated Cost	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
53	Subtotal		0.54	0.57	0.29	0.56	0.49	0.47	0.40	0.54	0.49	1.07
54	Capacity Related											
55	Wholesale Cost	¢/kWh	1.61	1.90	0.00	1.47	1.30	0.99	0.79	1.20	1.29	1.35
56	Allocated Cost	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57	Subtotal	¢/kWh	1.61	1.90	0.00	1.47	1.30	0.99	0.79	1.20	1.29	1.35
58	Energy Related											
59	Wholesale Cost	¢/kWh	4.34	4.42	4.23	4.43	4.43	3.89	4.02	3.51	4.43	4.20
60	Allocated Cost	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	Subtotal	¢/kWh	4.34	4.42	4.23	4.43	4.43	3.89	4.02	3.51	4.43	4.20
62	Sub. Power Supply	¢/kWh	6.49	6.89	4.52	6.46	6.22	5.35	5.20	5.25	6.21	6.62
63	Transmission											
64	Direct	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65	Capacity	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66	Energy	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
67	Allocated Cost	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
68	Sub. Transmission	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69	Distribution											
70	Direct	$/Mo./cons	1.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.91
71	Consumer	$/Mo./cons	31.42	30.49	6.95	38.71	77.15	95.62	95.62	95.62	143.91	1.52
72	Capacity	¢/kWh	1.17	1.28	1.29	1.25	1.09	0.87	0.78	0.99	1.14	1.42
73	Energy	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
74	Sub. Distribution	¢/kWh	3.12	4.06	3.70	3.54	1.22	0.88	0.78	1.03	1.57	13.67
75	Total	¢/kWh	9.61	10.95	8.23	10.00	7.44	6.23	5.98	6.28	7.78	20.29
76	Costs Broken Down by Classification											
77	Direct	¢/kWh	0.61	0.57	0.29	0.56	0.49	0.47	0.40	0.54	0.49	10.42
78	Consumer	$/Mo./cons	31.42	30.49	6.95	38.71	77.15	95.62	95.62	95.62	143.91	1.52
79	Capacity	¢/kWh	2.78	3.18	1.29	2.72	2.39	1.86	1.56	2.19	2.43	2.76
80	Energy	¢/kWh	4.34	4.42	4.23	4.43	4.43	3.89	4.02	3.51	4.43	4.20
81	Total		9.61	10.95	8.23	10.00	7.44	6.23	5.98	6.28	7.78	20.29

Rebecca Witt

From: Laslie, Jeffrey [lasliej@powersystem.org]
Sent: Tuesday, June 01, 2010 4:04 PM
To: O. V. Sparks; Michael Miller ; Mark Stallons; Rebecca Witt; Larry Hicks ; Eddie Boone; Debra Martin
Subject: Reciept of EKPC Rate Study - Cost of Service Results

Dear All,

On Thursday, May 27th we sent a letter accompanied by the preliminary cost of service results to your respective coops via email. To confirm they were all delivered, I will appreciate your replying to this email and letting me know if you received the letter.

Thank you,
Jeff

Jeff Laslie
Power System Engineering, Inc.
Phone: 317-322-5906
Fax: 317-322-5924
Cell: 317-696-0820
lasliej@powersystem.org

Rebecca Witt

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Tuesday, July 27, 2010 8:42 AM
To: Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; Dan Brewer (E-mail); Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); bprather@farmersrecc.com; Wayne Davis; Jerry Carter; cperry@fme.coop; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; Carol Wright; Mark Keene; rodneychrisman@jacksonenergy.com; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Cheryl Thomas; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; Nicky Rapier; J. Edward Boone (E-mail); randyb@srelectric.com; debbiem; gay; denise@shelbyenergy.com; Allen Anderson; Stephen Johnson; Ruby Patterson; Amy Acton; Barry Myers (E-mail); John Patterson; abeard@tcrecc.com
Cc: jimadkins25@aol.com; Tony Campbell; Stacy Barker; Mike McNalley; John Twitchell; Craig Johnson; Denver York; forward to davismart at FTB; Bob Daniel; Mike Steffes
Subject: Status Update - Rate Design Feasibility Study

Ladies & Gentlemen,

When EKPC awarded the contract to Power System Engineering in January 2010 for the Rate Design Feasibility Study, the plan was for the project to be completed by July 31, 2010. We recognized going in that this was an ambitious target, and Power System designed its work plan to complete the work by that deadline. However, during the last few months, there have been some delays in getting information exchanged between us and Power System. The result is that Power System will not be able to complete the project by the original July 31, 2010 deadline. We have discussed this situation with them and Power System believes it can complete the project by August 31, 2010. Power System believes that it can complete the project within the original budget total of $472,725 and plans on making effort to do so. As a result, we have extended the project deadline to August 31, 2010 with no change in the total cost. I will let you know if there are further developments. Thank you.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

From: Isaac Scott [isaac.scott@ekpc.coop]
Sent: Tuesday, August 31, 2010 3:19 PM
To: Bobby Sexton (E-mail); destepp@bigsandyrecc.com; badavis@bigsandyrecc.com; Dan Brewer; Donald Smothers; Cathryn W. Gibson; Paul Embs (E-mail); David Duvall; Holly Eades (E-mail); Ted Hampton (E-mail); Robert Tolliver (E-mail); Bill Prather; Wayne Davis; Jerry Carter; cperry@fme.coop; jhazelrigg@fme.coop; Mary Beth Nance; carol.fraley@graysonrecc.com; Don Combs; kim.bush@graysonrecc.com; Jim Jacobus; Vickie Lay (E-mail); Sheree Gilliam; Don Schaefer; Sharon Carson; Carol Wright; Mark Keene; Rodney Chrisman; Kerry Howard (E-mail); Sandra Bradley (E-mail); maudie@lvrecc.com; Mickey Miller; O. V. Sparks; rryan@nolinrecc.com; Cheryl Thomas; Mark Stallons; Rebecca Witt; Mike Cobb; larryh@srelectric.com; Nicky Rapier; J. Edward Boone (E-mail); randyb@srelectric.com; Debbiem; gay; denise@shelbyenergy.com; Allen Anderson; Stephen Johnson; Ruby Patterson; Amy Acton; bmyers@tcrecc.com; jpatterson@tcrecc.com; abeard@tcrecc.com
Cc: jimadkins25@aol.com; Tony Campbell; Stacy Barker; Mike McNalley; John Twitchell; Craig Johnson; Denver York; forward to davismart at FTB; Mike Steffes; Ann Wood
Subject: Status Update - Rate Design Feasibility Study

Ladies and Gentlemen,

As you will recall, when EKPC awarded the contract to Power System Engineering in January 2010 for the Rate Design Feasibility Study, the plan call for the project to be completed by July 31, 2010. Due to some delays in getting information exchanged between us and Power System, the completion date was moved to August 31, 2010 at no change in the total cost.

During August, EKPC received a data request in the pending general rate case from the Commission Staff asking that the cost-of-service study be presented by rate classes. While preparing the response, Power System suggested and we agreed that a similar analysis should be incorporated into the wholesale cost-of-service study being prepared for the Rate Design Feasibility Study. The inclusion of this item has required some additional information to be provided to Power System, and the processing of this additional information has delayed the completion of the wholesale portion of the Study, which in turn has delayed the completion of the retail portion of the Study. Because of this delay, the completion date has been revised to October 20, 2010, again at no change in the total cost of the project.

If you have any questions, please feel free to contact me. Thank you.

Isaac S. Scott
Manager - Pricing
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, Kentucky 40392-0707
859.745.9243
isaac.scott@ekpc.coop

Rebecca Witt

From: Cuellar, Marilyn [cuellarm@powersystem.org] on behalf of Macke, Rich [macker@powersystem.org]
Sent: Wednesday, October 20, 2010 5:04 PM
To: Mark Stallons
Cc: Rebecca Witt; Isaac.scott@ekpc.coop; lasliej@powersystem.org
Subject: OE-Retail Report: EKPC Wholesale & Retail Rates Feasibility Study
Attachments: OE-EKPC Wholesale-Retail Rates Feasibility Study-10-20-10.pdf

Mr. Stallons,

Please see the attached Retail Report which is part of the completed EKPC Wholesale & Retail Rates Feasibility Study. In addition, we will be sending two hard copies of the report. It has been a pleasure working with you and your staff on this project.

Best regards,

Rich Macke
Vice President, Rates and Financial Planning
Power System Engineering, Inc.
Office: 763-783-5349
Mobile: 612-817-3462
Fax: 763-755-7028
macker@powersystem.org
www.powersystem.org

October 21, 2010

Mr. Mark Stallons
President and CEO
Owen Electric Cooperative
P.O. Box 400
Owenton, KY 40359-0400

Subject: Owen Retail Report: EKPC Wholesale & Retail Rates Feasibility Study

Dear Mr. Stallons:

Enclosed are two (2) copies of the Retail Report, which is part of the completed EKPC Wholesale & Retail Rates Feasibility Study. The Report was prepared for Owen Electric Cooperative by Power System Engineering, Inc. It was a pleasure working with you and your staff on this project. Please contact me if you have any questions.

Very truly yours,

Richard J. Macke

Richard J. Macke
Vice President, Rates and Financial Planning

KY0591018/mmc

cc: Becky Witt, Owen
Isaac Scott, EKPC
Jeff Laslie, PSE

Enclosures

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the power to help you succeed.

Owen Electric Cooperative Owenton, KY

East Kentucky Power Cooperative Wholesale & Retail Rates Feasibility Study

October 20, 2010

Contact: Richard J. Macke
10710 Town Square Drive NE, Suite 201
Minneapolis, MN 55449
Office: 763-755-5122
Mobile: 612-817-3462
Fax: 763-755-7028
Email: macker@powersystem.org
Web Site: www.powersystem.org

Confidential, Copyrighted, and Proprietary

October 21, 2010

Mr. Mark Stallons
President and CEO
Owen Electric Cooperative
P.O. Box 400
Owenton, KY 40359-0400

Subject: Owen Retail Report: EKPC Wholesale & Retail Rates Feasibility Study

Dear Mr. Stallons:

Enclosed are two (2) copies of the Retail Report, which is part of the completed EKPC Wholesale & Retail Rates Feasibility Study. The Report was prepared for Owen Electric Cooperative by Power System Engineering, Inc. It was a pleasure working with you and your staff on this project. Please contact me if you have any questions.

Very truly yours,

Richard J. Macke
Vice President, Rates and Financial Planning

KY0591018/mmc

cc: Becky Witt, Owen
Isaac Scott, EKPC
Jeff Laslie, PSE

Enclosures

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1.0 Introduction

1.1 Scope

Owen Electric Cooperative (Owen or Cooperative) is located in Owenton, Kentucky. The Cooperative provides electric service to approximately 57,000 consumers through 4,500 miles of distribution line. In an effort to evaluate wholesale and retail rate design issues, East Kentucky Power Cooperative (EKPC) retained Power System Engineering, Inc. (PSE) to complete a Wholesale & Retail Rates Feasibility Study. As part of this study, PSE has prepared a retail rate and cost of service (COS) study for Owen under the existing EKPC wholesale rates and under proposed EKPC wholesale rates which were separately developed. The major purpose in conducting this study is to gauge the impact that a proposed EKPC wholesale rate would have on the Cooperative's 1) revenue requirements, 2) class COS results and 3) rate structures, design and programs.

The details of each of the major tasks are discussed in the balance of this report as follows:

Section 3.0 - Revenue Requirements;
Section 4.0 - Class Cost of Service Analysis; and
Section 5.0 - Rate Implementation Plan Factors.

The study's Test Year revenue requirements analysis is based upon the Cooperative's operating results for the calendar year 2009 (CY2009) with two exceptions. First, revenue has been calculated independently by applying the present rates, including the Environmental Surcharge Rider (ESR)[1] and Fuel Adjustment Charge (FAC)[2], to the CY2009 retail billing determinants by rate schedule. Second, purchased power expense has been determined based upon the proposed EKPC wholesale rates as separately determined in the wholesale rate study.

---

[1] The ESR for the study was based on 2009 actual ESR costs incurred. The proposed wholesale rate for EKPC included rolling the ESR into base rates.

[2] The FAC for the study was synchronized so that is reflects a direct pass through of wholesale purchased power FAC expenses as per the wholesale study that was completed separately.

The balance of this report presents our summary and conclusions along with discussions of various procedures, methodologies, assumptions and reasoning employed in completing the study. Following the narrative sections of the report, PSE has included a number of Exhibits that present the specific analysis details and summary sheets.

2.0 Summary and Conclusions

2.1 Summary

The report presents our analysis of Owen's revenue requirements, class COS and rate design within the context of the Test Year under the proposed wholesale rates for EKPC. Analysis was also conducted under the present wholesale rates of EKPC in order to gauge the potential impact of the proposed wholesale rates on the Cooperative's 1) revenue requirements, 2) class COS results and 3) rate structures, design and programs.

2.2 Revenue Requirements - Summary

The revenue requirements of a cooperative simply refer to the total cost of doing business and are comprised of operating expenses plus margin requirements. By comparing the revenue requirements against revenue under present rates, the adequacy of the present rates can be assessed. The following Tables 1 and 2 present a summary of revenue requirements analysis for the Test Year under both a Modified Times Interest Earned (M-TIER) method and a Rate of Return on Rate Base (ROR) method.

Table 1
Revenue Requirements Summary
Method A - M-TIER = 2.00 Objective

		($)
1.	Operating Expenses (Excluding Interest)	139,845,295
2.	Margin Requirements	
	a. Interest expense	4,564,974
	b. Target TIER	2.00
	c. Total Margin Requirements (Before Interest)	9,129,948
	d. Less: Non-Operating Income	105,017
	e. Less: Other Capital Credits	244,923
	f. Net Operating Income Required	8,780,008
3.	Total Revenue Requirements	148,625,304
4.	Revenue From Present Rates	
	a. Tariff Revenue	144,588,388
	b. Other Operating Revenue	1,874,169
	c. Total Revenue	146,462,557
5.	Required Increase (Decrease)	2,162,747
	or	1.5%

Table 2
Revenue Requirements Summary
Method B - Rate of Return Objective

		($)
1.	Operating Expenses (Excluding Interest)	139,845,295
2.	Margin Requirements	
	a. Rate Base	135,757,983
	b. Rate of Return	6.09%
	c. Total Margin Requirements (Before Interest)	8,267,378
	d. Less: Non-Operating Income	105,017
	e. Net Operating Income Required	8,162,360
3.	Total Revenue Requirements	148,007,656
4.	Revenue From Present Rates	
	a. Tariff Revenue	144,588,388
	b. Other Operating Revenue	1,874,169
	c. Total Revenue	146,462,557
5.	Required Increase (Decrease)	1,545,099
	or	1.1%

The details for supporting the preceding tables can be found in Exhibits 2 and 3 of the report.

As previously noted, the purpose of the study is not to determine an overall rate increase or decrease need. For that reason, the increases noted above have not resulted in an overall rate change recommendation or proposal. However, the study could be updated at a later date to support an overall rate change application.

2.3 Class Cost of Service - Summary

Using the results of the M-TIER revenue requirements analysis, PSE performed a class COS analysis (Exhibit 4). This analysis is aimed at identifying the cost responsibility of each rate class versus the revenue being generated under present retail rates. The COS is also useful in determining the cost component of each rate class (i.e., customer, energy and demand costs).

The results of the class COS analysis prepared using the proposed wholesale rates for EKPC are summarized in Table 3.

Table 3
Class Cost of Service Summary

Rate Class	Present Rate Revenue	Cost of Service	Difference	As Percent
	($)	($)	($)	
Schedule I Farm And Home	71,314,123	77,892,192	6,578,069	9.4%
Schedule I-A Residential Marketing	1,388	2,278	890	65.3%
Schedule I(2) Small Commercial	4,559,976	4,529,674	(30,302)	(0.7%)
Schedule II Large Power	15,271,169	11,613,294	(3,657,875)	(24.4%)
Schedule XI Large Industrial LPB1	4,843,662	4,349,374	(494,288)	(10.4%)
Schedule XIII Large Industrial LPB2	6,603,278	6,968,562	365,284	5.6%
Schedule XIV Large Industrial LPB	897,227	684,629	(212,598)	(24.1%)
Schedule 2-A Large Power Time of Day	312,315	290,370	(21,944)	(7.2%)
Outdoor Lighting Service	1,555,617	1,191,129	(364,488)	(23.9%)
Total	105,358,755	107,521,502	2,162,747	2.1%

As the above table illustrates, there are presently some cross subsidies between the rate classes with respect to cost recovery. It is important, at this point, to distinguish between the COS and actual rate design. Due to the limitations inherent to a COS analysis, these results should be viewed as providing a general range of where rates should be. It is, in fact, uncommon for rates to be designed exactly in line with COS results.

Of primary importance in this study is the evaluation of the impact a new EKPC wholesale rate structure could have on the Cooperative's retail rates. In determining this, PSE performed a COS analysis under both EKPC's present rate and the proposed rates. The COS under EKPC's present wholesale rate is contained in Exhibit 5. A comparison of the impact of the proposed wholesale rates for EKPC on the retail COS analysis is shown as follows in Table 4.

Table 4
Comparison of Class Cost of Service
Proposed and Present EKPC Wholesale Rate Design

Rate Class	EKPC Proposed Rate Design		EKPC Present Rate Design		Percent Change
	Incr/(Decr) Required	As Percent	Incr/(Decr) Required	As Percent	
	($)	(%)	($)	(%)	(%)
Schedule I - Farm And Home	6,578,069	9.4%	7,115,959	10.2%	-0.8%
Schedule I-A - Residential Marketing	890	65.3%	877	64.4%	0.9%
Schedule I(2) - Small Commercial	(30,302)	-0.7%	(11,184)	-0.2%	-0.4%
Schedule II - LargePower	(3,657,875)	-24.4%	(3,739,213)	-24.9%	0.5%
Schedule XI - Large Industrial LPB1	(494,288)	-10.4%	(533,619)	-11.2%	0.8%
Schedule XIII - Large Industrial LPB2	365,284	5.6%	219,743	3.4%	2.2%
Schedule XIV - Large Industrial LPB	(212,598)	-24.1%	(208,539)	-23.7%	-0.5%
Schedule 2-A - Large Power Time of Day	(21,944)	-7.2%	(23,235)	-7.6%	0.4%
Outdoor Lighting Service	(364,488)	-23.9%	(296,161)	-19.4%	-4.5%
Total Cooperative	2,162,747	2.1%	2,524,628	2.4%	-0.3%

The table above illustrates that the proposed EKPC rate design has a mixed impact on residential and commercial and industrial rate classes; with some rate classes increasing in cost of service and others decreasing. Regardless, the impact is not very substantial.

Additional details and evaluation of the COS impacts are contained in Exhibit 6.

2.4 Rate Implementation Plan Factors

The rate implementation plan factors are comprised of three key components: 1) COS results versus present rate design, 2) impact of proposed EKPC wholesale rates and 3) Energy Independence and Security Act of 2007 (EISA) considerations and time-of-use (TOU) rates.

COS Results Versus Present Rate Design

The COS analysis is used to evaluate the present retail rates in terms of cost recovery by rate schedule and in terms of rate structure design. As per the COS summary table and as expected, there are cross-class subsidies in the present rates. It is unlikely that these cross-class subsidies could be eliminated during the course of one rate change, even if that were desirable. The consumer bill impact often times limit the extent to which cross-class subsidies can be addressed during a given rate case.

As part of establishing an overall rate setting strategy to guide future decisions, we suggest that the Cooperative consider the following.

1. Establish rate class maximum and/or minimum increase levels during a rate application:
    a. Set based on a multiple of the system average; i.e., 2x's.
    b. Set a maximum increase for any rate class; i.e., 15 percent.
    c. Determine how to handle rate decreases during an overall increase and vice versa.
    d. Combination of the above.
2. Determine M-TIER bandwidth (1.5 to 2.5 M-TIER) and a plan for getting each rate class within this maximum and minimum M-TIER bandwidth.
3. Develop a plan for increasing the customer charges in the direction of the COS results. Set maximum increase limits to prevent rate shock for low-usage customers.
4. Set a goal of recovering non-primary line consumer-related costs in the customer charge within 5 or 7 years.
5. Monitor the level of the demand charge for consumers with demand charge billing. With the expectation that future rate design changes from EKPC will result in increased demand versus energy charges, it is recommended that the Cooperative consider whether its retail demand charges will also need to be increased. It has been determined that, for at least some of the Cooperative's rates, the present demand charge is below the COS determined level. This results in demand-related costs being recovered in energy charges, which causes higher than average load factor customers to subsidize lower than average load factor customers.

6. Develop an alternative commercial and industrial rate design for coincidental demand billing. Such a rate design, when coordinated with EKPC, can prove to be a mutually beneficial demand-side management (DSM) program.
7. Explore the viability of a residential critical peak rate offering.

Impact of Proposed EKPC Wholesale Rates

The attached Exhibit 6 provides a comparison of the Cooperative's COS under the present and proposed wholesale rates for EKPC. The proposed EKPC wholesale rate places somewhat more emphasis on the demand charge versus energy charge, which tends to benefit the higher than average load factor and/or lower than average coincidence factor rate classes. The impact is not significant but would tend to put some additional pressure on the future need to increase residential rates and demand charges in demand-billed rate classes.

EISA and TOU Rates

The Energy Independence and Security Act of 2007 (EISA) deals with the electric industry in Public Title V - Energy Savings in Government and Public Institutions, Subtitle D, Utility Energy Efficiency Programs. This section of EISA modifies Title I of PURPA of 1978, which requires covered electric utilities and/or regulatory bodies to consider a number of "rate design" standards such as cost of service, master metering, time-of-use rates, etc. EISA adds four new standards to be considered. The four new "rate design" standards to be considered under EISA are:

1. The inclusion of the consideration of energy efficiency in the Integrated Resource Planning (IRP) process;
2. The adoption of rate design modifications to promote energy efficiency (EE) investments;
3. The consideration of smart grid investments in lieu of other system improvements; and
4. The provision of energy price and other information to consumers.

Section 5.0 of this report contains further discussion on EISA and its potential influence on the pricing of electricity.

Exhibit 8 of this report presents the development of example TOU rate designs for the Cooperative.

3.0 Revenue Requirements

3.1 General

In order to ensure financial viability, a cooperative's retail rates must be designed to generate sufficient revenue to meet operating expenses and margin requirements. The margin requirements for a cooperative must be adequate to cover interest expense and accomplish other capital management objectives such as rotating patronage capital and maintaining (or achieving) a desired equity position, as discussed in Section 3.3. In this report we will refer to the total operating expense and margin requirements as the "revenue requirements" of the Cooperative.

REVENUE REQUIREMENTS = OPERATING EXPENSE + MARGIN REQUIREMENTS

To evaluate a cooperative's revenue requirements and the adequacy of its present rate structure to meet these requirements, it is common practice to analyze revenue and costs for a 12-month period of time, commonly referred to as the "Pro Forma Test Year," or simply the "Test Year." The Test Year for this study is based upon the Cooperative's operating results for CY2009.

3.2 Operating Expenses

Operating Statements for Actual 2009 and the Test Year are shown on page 1 of Exhibit 2. The revenue estimated for the Test Year was developed using the present rate schedules including the PCA and ESR applied to 2009 sales by rate schedule. The Test Year operating expenses were based on expenses for 2009, with the exception that the purchased power expense was independently determined based on the proposed wholesale rates for EKPC.

It is important to distinguish between operating income or margins and total income. Use of the term "operating" is intended to designate revenue and expenses associated with the basic utility function (i.e., supplying electric service to consumers). It is to be distinguished from Non-operating Income, such as interest earnings from short-term investments and patronage capital credit assignments from associated organizations. Because Non-operating Income is outside the operations and direct control of the distribution cooperative, it is not generally considered in establishing the revenue requirements for retail rate making purposes; although as discussed later in the next section, interest earnings are considered in the M-TIER calculation. Retail rates are generally designed to be sufficient, but only sufficient, to cover the operating revenue requirements, with credit sometimes given to interest earnings.

3.3 Margin Requirements

To complete the Test Year Revenue Requirements, an appropriate level of margin must be added to the previously determined operating expenses. In establishing the level of margin required to achieve the Cooperative's financial objectives, we have utilized two tests: 1) M-TIER = 2.00 and 2) ROR. The M-TIER, which is a measure of the ability of the Cooperative to cover its long-term interest expense obligation, is defined as follows:[3]

$$\text{M-TIER} = \frac{\text{Operating Margin} + \text{Interest Expense} + \text{Interest Income}}{\text{Interest Expense}}$$

The Rural Utilities Service (RUS) requires borrowers to maintain a TIER of at least 1.25. TIER is very similar to M-TIER except that it is based on total or net margin. Falling below this level represents a default of the mortgage agreement. Thus, a Targeted TIER in excess of 1.25 is generally desirable to provide for unforeseen events. For purposes of this study, we have established an M-TIER of 2.00 as the target. In order to achieve an M-TIER of 2.00 under Test Year conditions, Owen could justify a rate increase of approximately $2,163,000 or 1.5 percent.

The second test, ROR, is a traditional method of establishing the margin requirements that has long been used in regulatory proceedings. When applied to investor-owned utilities, the method ensures that earnings are sufficient to cover the cost of debt (interest) and generate a fair return on the investment (equity) of the owners. Likewise, when applied to cooperatives, the concept permits the development of sufficient margins to cover the cost of debt and equity capital. However, in the case of cooperatives, the term "return on equity" involves a totally different concept than it does for investor-owned utilities. Return on (or of) equity for cooperatives is

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[3] Typically, only the interest expense associated with long-term debt is included in this calculation.

related to the retirement, or rotation, of patronage capital. Thus, the ROR required by a specific cooperative must result in sufficient margins to:

1. Pay interest expense on long-term debt;
2. Rotate patronage capital as stated in the policy of the cooperative; and
3. Maintain or achieve the desired equity position.

Rate base represents an approximation of a cooperative's investment in facilities which are "used and useful" in serving its customers. The Cooperative's rate base is shown in Exhibit 3, Schedules A and B. The other schedules of Exhibit 3 show the calculation of the required ROR. The calculated return on equity is designed to permit the rotation of capital on the cycle established by the Cooperative's Board, recognizing the Cooperative's compound rate of growth in net plant. In this case, the rotation cycle is 20 years; and the compound annual growth rate as measured over the past five years is 4.7 percent. The ROR method supports an increase of $1,545,000 or 1.1 percent.

The M-TIER method was used as the basis for the COS as it is more applicable and has more historical use by the Cooperative.

4.0 Class Cost of Service Analysis

4.1 General

A class COS analysis has been prepared to provide information that will be used in evaluating the present retail rates and the impact of the proposed wholesale rates of EKPC. The basic objective of a COS analysis is to identify the cost of providing service to each rate class as a function of load and service characteristics. The methodology employed is often referred to as the "fully allocated average embedded" COS approach, meaning that 1) costs are allocated on an average system-wide basis and 2) embedded or accounting costs as recorded on the Cooperative's books are used in the analysis. We believe that this is generally the most appropriate technique to use in allocating cost responsibility to the various classes and developing rate design data for rural electric cooperatives.

4.2 Limitations and Uses

It is vital at the outset to recognize some of the inherent limitations of such a COS study. First, it must be emphasized that a COS analysis, while basically an engineering and economic evaluation, is an art; not an exact science. There are many different methodologies, techniques and assumptions that have been and will continue to be advocated by rate analysts. Because the various philosophies and assumptions can significantly affect the result of the analysis, the results should be treated as providing an indication of the general range of class cost responsibility; not as precise values.

Second, a COS analysis is of necessity directed at determining the cost imposed by a rate class on the system rather than at determining the cost imposed by individual consumers within each classification. The cost responsibility of a specific, individual consumer may or may not be entirely consistent with the cost allocations made to their assigned consumer classification. Furthermore, the study does not address the problem of maintaining relatively smooth transitions between the various rate classes or subclasses of consumers which may be eligible to receive service under more than one rate schedule.

Third, accurate demand characteristics and load factor data for individual customer classes are often unavailable. Capacity allocations must therefore be made on the basis of estimates or "typical" data. Even in this case where extensive load research data was used, the result is still imprecise and requires assumptions and estimates. These assumptions or estimates can have a significant effect on the end results.

Fourth, a COS analysis does not address itself to many of the other legitimate objectives of rate design such as customer acceptance or the avoidance of excessively abrupt changes from the historical rate policies of the utility. In addition, it does not recognize the need to keep each rate schedule competitive, in as much as possible, with the corresponding rate schedule of neighboring utilities or the need to keep the rate structure simple so that it is administered and understood by consumers.

With the above limitations in mind, a COS study may be used as a general guide for assigning cost responsibility (i.e., revenue requirements) to each of the customer classifications in a manner which avoids unjustifiable price discrimination. The study also provides information useful in designing the individual rate schedules and provides support for justifying rate differentials to retail consumers.

4.3 Procedure

The basic procedure used to determine the cost responsibility of each consumer classification is as follows:

Step 1 - Classify the plant account records into basic cost causative categories.

Step 2 - Classify the Test Year expenses and margin requirements into the same cost causative categories.

Step 3 - Develop allocation factors for each rate class.

Step 4 - Allocate costs to the various rate classes using the class allocation factors developed for each cost causative category.

The class COS is provided in Exhibit 4.

4.4 Cost Causative Categories

Plant investments, Test Year expenses, and margin requirements for the COS study case are classified into the following cost causative categories:

1. Direct - Costs which are directly attributable to one specific customer classification. Expense associated with security lighting is an example of a direct expense.
2. Consumer - Costs that are the result of the number and location of each customer and which do not vary significantly with the demand imposed on the system or the amount of energy consumed. Metering and customer accounting expenses perhaps best illustrate this type of expense.
3. Capacity - Costs which result from providing and maintaining in readiness for operation facilities required to meet the peak demand whether it be the system peak, circuit peak or individual customer service peak. Much of the expense of operating and maintaining a three-phase backbone feeder would generally fall within this category as would the demand charge in the purchased power rate.
4. Energy - Costs which are related to the amount of energy used. The major item in this category is the energy charge in the purchased power rate.

Each of these general cost causative categories is further subdivided as follows:

Direct	Consumer	Capacity	Energy
As Assigned		Power Supply	Power Supply
		Distribution Substation	
	Primary Line	Primary Line	
	Line Transformer	Line Transformer	
	Secondary & Service		
	Meter		
	Customer Accounting		

4.5 Electric Plant Classification

The cost causative classification of the various electric plant accounts is presented on pages 4 and 5 of Exhibit 4. The methodology used in assigning the plant accounts to the cost causative categories is discussed as follows:

1. Intangible Plant (Acct. 301 - 303) - The Intangible Plant accounts were prorated to the cost categories in the same relationship as the distribution plant allocations.
2. Land, Structures, Station and Battery (Accts. 360 and 363) - The Land and Land Rights, Structures and Improvements, Station Equipment, and Battery accounts were classified as capacity related since the facilities represented by the investment are generally dictated by capacity considerations.
3. Primary Line and Devices (Accts. 364, 365, 366, 367) - Assignment of the Primary Line and Device accounts was based on results of the "Zero Intercept Method" (see pages 12 through 15 of Exhibit 4) to determine the consumer component share. The remaining amount was then assigned to the capacity component. The Zero Intercept Method is predicated on the theory that it is possible to develop a theoretical minimum cost required to provide an electrical path from the power supply sources to each existing consumer that is independent of either energy usage or capacity requirements. Accordingly, this theoretical minimum cost system that has "zero capacity" is properly defined as a consumer related cost. By subtracting this consumer related cost from the total replacement cost of the primary distribution system, based on actual conductor sizes and phasing, the consumer and capacity component allocation factors can be developed.
4. Line Transformers (Acct. 368) - Classification of the Line Transformer account was approached in similar fashion using the "Zero Intercept Method." (See pages 16 and 17

of Exhibit 4.) Again, it was reasoned that there exists a certain minimum transformer investment required to provide basic service to each consumer independent of energy usage or capacity requirements. This cost is assigned to the consumer component, while the remaining investment is considered capacity related.

5. Services and Meters (Accts. 369 and 370) - Because the investment in Services and Meters is basically independent of usage level, it was assigned entirely to the customer component.
6. Consumer Premise (Acct. 371) - The investment in installations on Consumer's Premises that are directly related to the Security Lighting Class was assigned directly to that class. The remainder was assigned to Primary Line.
7. Leased Property (Acct. 372) - Any investment in lighting facilities was assigned directly to that class. The remainder was assigned as Primary Line.
8. Street Lighting (Acct. 373) - Investment in street or security lighting facilities was assigned directly to the Security Lighting Class.
9. General Plant Accounts (Accts. 389 - 399) - The General Plant accounts were assigned to the cost causative categories in the same relationship as the total distribution plant allocations. Because the assignment of investment in general plant has minimal impact on the classification of Test Year expenses, which ultimately is used to determine class cost of service responsibility, a more detailed analysis of general plant investment was not warranted.

4.6 Revenue Requirements Classification

The Statement of Operations for the Test Year (Exhibit 2, page 1) forms the basis for the COS analysis. Actual expenses by account for the Test Year were used in the COS analysis.

The various components of the revenue requirements were classified to the four basic cost causative categories as presented on pages 6 through 11 of Exhibit 4. The factors used in the expense classification are summarized on pages 18 through 21 of Exhibit 4. The methodology and rationale for that methodology is discussed below:

1. Purchased Power (Acct. 555) - The demand and energy charge portions of the cost of Purchased Power were assigned to the capacity and energy components, respectively.

2. Transmission Operation and Maintenance (Acct. 560 - 573) - Transmission expense, if any, was assigned to the transmission capacity component.
3. Distribution Operation and Maintenance (Accts. 580 - 598) - Distribution expense accounts that are related to specific plant accounts (Accts. 582, 583, 584, 585, 586, 587, 591, 592, 593, 594, 595, 596 and 597) were classified in proportion to the corresponding plant accounts. These expenses result from operating and maintaining the distribution plant and, thus, may be considered plant related. The remaining distribution expense accounts (Accts. 580, 581, 588, 589, 590 and 598) were prorated on the basis of the sum of the previously assigned distribution expense accounts. These accounts basically represent overhead or general distribution expenses.
4. Consumer Accounting (Accts. 901 - 905) - Consumer Accounting expenses were assigned in total to the consumer component since this expense is basically independent of energy usage or capacity requirements. Instead, these accounts are related to the number of consumers.
5. Consumer Service and Information and Sales (Accts. 907 - 916) - Consumer Service and Information and Sales expenses are also considered consumer-related expenses.
6. Administrative and General (Accts. 920 - 932) - Administrative and General (A&G) expenses are common costs for which there exists no obvious relationship to the functional categories. Thus, we have assigned these expenses in proportion to the total of all other expenses without power supply.
7. Other Taxes, Other Interest, and Other Deductions - Other Taxes, Other Interest, and Other Deductions were assigned in a manner similar to the A&G Accounts.
8. Depreciation and Amortization (Accts. 403 - 407) - Depreciation and Amortization expense was allocated in proportion to the total plant account assignments.
9. Property Taxes (Acct. 408) - Property Taxes were assigned in proportion to the total plant account assignments.
10. Net Operating Income (Margin Requirements) - Two rationale approaches exist for assigning the margin requirements to the cost causative categories. First, if margin is comprised of interest expense and return on equity, both related to plant investment, it is reasonable to classify this cost in proportion to the total plant assignments. Furthermore, if the margin requirements were viewed from the perspective of the M-

TIER methodology, such would also logically be considered a function of plant investment.

On the other hand, if actual margins are ultimately allocated to the account of each member-consumer on the basis of revenue, a classification method that tracks the way margins are returned to the member-owners of the cooperative also has its appeal. However, since typically 60 to 70 percent of the large power class's cost and revenue relates to recovery of power supply expenses, it would be difficult to rationalize allocating margin requirements in this manner, especially when little or no investment is assigned to the function. Furthermore, it is unlikely that a competitive environment would permit the assignment of margin of this magnitude to a competitive power supply marketplace.

In this study we have classified the margin requirements (both long-term interest and margins) on the basis of total plant investment.

4.7 Allocation of Costs to General Rate Classes

The allocation of the revenue requirements to each consumer classification is presented on pages 24 through 26 of Exhibit 4. The allocations are based on various allocation factors that reflect certain cost causative drivers as discussed below:

1. Direct Cost Allocation - Costs specifically associated with street or security lighting facilities (investment and Operation and Maintenance (O&M)) directly assigned to the Lighting Class is an example of a possible direct cost allocation.
2. Consumer Costs Allocations - Generally speaking, consumer related costs were allocated to the various classes on the basis of the total number of consumers in each class. However, several adjustments were made in the general allocation procedure to reflect differences in the cost of providing basic service. Weighting factors were developed on page 27 of Exhibit 4 to recognize the higher cost of three-phase service versus standard single-phase service for each subcategory of consumer related cost.
3. Capacity Cost Allocations - Three different allocation factors were developed for the capacity component. (See pages 28 through 30 of Exhibit 4 for the development of class demands):

a. Line transformer capacity related costs were allocated in accordance with the estimated average monthly, undiversified non-coincidental peak demand of each consumer in each class as this definition of demand most closely approximates transformer capacity requirements.

b. Primary line capacity allocated costs were allocated using the Average and Excess Demand Method based on the average monthly coincidental demand for each class (not necessarily coincidental with the system). Distribution system capacity related costs are a function not only of the system peak, but also the individual circuit and even consumer peak demand. The Average and Excess Demand Method gives recognition to the average demand imposed on the system by each class as well as the average monthly peak demand of the class (non-coincidental) and prevents any class from getting a "free ride" from a capacity standpoint.

c. Purchased power demand charges were allocated in accordance with the average monthly coincidental class demands.

d. Distribution substation capacity costs were allocated using the Average and Excess Demand method.

e. Transmission capacity costs, if any, were allocated in accordance with the average monthly non-coincidental class demands.

4. Energy Cost Allocations - Energy related costs were allocated on the basis of on-peak, and off-peak energy sales to each rate class.

Allocation factors for each category are developed on pages 31 and 32 of Exhibit 4.

4.8 Summary of Cost of Service - Proposed Wholesale Rates of EKPC

Results obtained from the COS analysis are summarized in Tables 5, 6 and 7 on the following pages.

Table 5 provides a comparison of the calculated cost of providing service to each rate class with the revenue generated under the present rates by that class.

Table 5 Class Cost of Service Summary				
Rate Class	Present Rate Revenue	Cost of Service	Difference	As Percent
	($)	($)	($)	
Schedule I Farm And Home	71,314,123	77,892,192	6,578,069	9.4%
Schedule I-A Residential Marketing	1,388	2,278	890	65.3%
Schedule I(2) Small Commercial	4,559,976	4,529,674	(30,302)	(0.7%)
Schedule II Large Power	15,271,169	11,613,294	(3,657,875)	(24.4%)
Schedule XI Large Industrial LPB1	4,843,662	4,349,374	(494,288)	(10.4%)
Schedule XIII Large Industrial LPB2	6,603,278	6,968,562	365,284	5.6%
Schedule XIV Large Industrial LPB	897,227	684,629	(212,598)	(24.1%)
Schedule 2-A Large Power Time of Day	312,315	290,370	(21,944)	(7.2%)
Outdoor Lighting Service	1,555,617	1,191,129	(364,488)	(23.9%)
Total	105,358,755	107,521,502	2,162,747	2.1%

Table 6 shows a breakdown of the cost of service by cost category for each class.

Table 6 Class Cost of Service Class Allocation Summary					
	Power Supply		Distribution		Total
Rate Class	Capacity	Energy	Consumer	Capacity	COS
	($)	($)	($)	($)	($)
Schedule I Farm And Home	13,830,293	34,332,398	20,033,173	9,696,328	77,892,192
Schedule I-A Residential Marketing	-	1,226	666	385	2,278
Schedule I(2) Small Commercial	775,401	2,262,340	849,843	642,091	4,529,674
Schedule II Large Power	1,356,233	8,640,611	300,179	1,316,270	11,613,294
Schedule XI Large Industrial LPB1	712,620	2,856,307	14,836	765,611	4,349,374
Schedule XIII Large Industrial LPB2	921,890	4,804,171	3,297	1,239,204	6,968,562
Schedule XIV Large Industrial LPB	139,232	415,210	6,594	123,594	684,629
Schedule 2-A Large Power Time of Day	49,184	176,472	23,421	41,293	290,370
Outdoor Lighting Service	192,176	363,028	499,519	136,406	1,191,129
Total	17,977,029	53,851,763	21,731,527	13,961,183	107,521,502

Table 7 provides total costs by class expressed in terms of \$/customer/month (consumer component) and ¢/kWh (capacity and energy components).

Table 7 Class Cost of Service Rate Design Factors					
	Power Supply		Distribution		Total
Rate Class	Capacity	Energy	Consumer	Capacity	Cost
	(¢/kWh)	(¢/kWh)	($/mo.)	(¢/kWh)	(¢/kWh)
Schedule I Farm And Home	1.95	4.83	$ 30.87	1.36	10.96
Schedule I-A Residential Marketing	-	4.44	$ 6.94	1.39	8.24
Schedule I(2) Small Commercial	1.66	4.85	$ 30.87	1.38	9.71
Schedule II Large Power	0.76	4.86	$ 100.06	0.74	6.53
Schedule XI Large Industrial LPB1	1.05	4.23	$ 137.37	1.13	6.43
Schedule XIII Large Industrial LPB2	0.84	4.37	$ 137.37	1.13	6.34
Schedule XIV Large Industrial LPB	1.28	3.82	$ 137.37	1.14	6.29
Schedule 2-A Large Power Time of Day	1.35	4.86	$ 216.86	1.14	7.99
Outdoor Lighting Service	2.32	4.38	$ 3.24	1.64	14.36
Total - Average	1.58	4.74	$ 31.95	1.23	9.47

4.9 Summary of Cost of Service - Present Wholesale Rates of EKPC

In addition to the above COS results, which were completed based upon the proposed wholesale rate for EKPC, an additional COS was completed utilizing the present wholesale rates for EKPC. This COS analysis is contained in the attached Exhibit 5.

4.10 Summary of Cost of Service - Comparison

As a final step in the COS study, a comparison was prepared to evaluate the impact that the proposed wholesale rate for EKPC would have on the retail COS results for the Cooperative. The proposed wholesale rate for EKPC includes an increase in the demand charge relative to energy charges. A comparison of the present and proposed Section E[4] wholesale rate for EKPC is shown below:

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[4] EKPC's Section E wholesale rate is the rate under which the Cooperative makes its general power supply purchases. The present Section E wholesale rate has two options. However, only one EKPC Member utilizes Option 1. Because of this, it is recommended that the two options be combined.

EKPC Schedule E		Present	Proposed[5]
Demand Charge	@	$6.22/kW	$7.38/kW
Energy Charge			
On-Peak	@	$0.05324/kWh	$0.04877/kWh
Off-Peak	@	$0.04421/kWh	$0.04277/kWh

Because the wholesale demand charge is increased relative to the energy charge, it was expected that EKPC Members with higher than average load factors would experience a decrease in average purchased power costs relative to lower than average load factor Members. The same is true when it comes to retail rate classes. Rate classes with higher than average load factors are expected to experience a decrease in COS relative to lower than average rate classes. However, given the minor shift in EKPC charges from energy to demand, any shift in retail COS is expected to be minor.

Table 8 summarizes the retail COS results under the proposed and present wholesale rates of EKPC.

Table 8
Comparison of Class Cost of Service
Proposed and Present EKPC Wholesale Rate Design

	EKPC Proposed Rate Design		EKPC Present Rate Design		
Rate Class	Incr/(Decr) Required	As Percent	Incr/(Decr) Required	As Percent	Percent Change
	($)	(%)	($)	(%)	(%)
Schedule I - Farm And Home	6,578,069	9.4%	7,115,959	10.2%	-0.8%
Schedule I-A - Residential Marketing	890	65.3%	877	64.4%	0.9%
Schedule I(2) - Small Commercial	(30,302)	-0.7%	(11,184)	-0.2%	-0.4%
Schedule II - LargePower	(3,657,875)	-24.4%	(3,739,213)	-24.9%	0.5%
Schedule XI - Large Industrial LPB1	(494,288)	-10.4%	(533,619)	-11.2%	0.8%
Schedule XIII - Large Industrial LPB2	365,284	5.6%	219,743	3.4%	2.2%
Schedule XIV - Large Industrial LPB	(212,598)	-24.1%	(208,539)	-23.7%	-0.5%
Schedule 2-A - Large Power Time of Day	(21,944)	-7.2%	(23,235)	-7.6%	0.4%
Outdoor Lighting Service	(364,488)	-23.9%	(296,161)	-19.4%	-4.5%
Total Cooperative	2,162,747	2.1%	2,524,628	2.4%	-0.3%

5 The proposed wholesale rate for EKPC includes a rolling in of the presently separate Environmental Surcharge into the base rates.

The table above illustrates that the proposed EKPC rate design has a mixed impact on residential and commercial and industrial rate classes; with some rate classes increasing in cost of service and others decreasing. Regardless, the impact is not very substantial.

For additional comparative information, please reference the attached Exhibit 6. Other implications of the proposed EKPC wholesale rate design are addressed in Section 5.0 of this report.

5.0 Rate Implementation Plan Factors

5.1 General

Various tables showing the results of the COS analysis are useful in discussing the evaluation of Owen's rates and future rate design objectives. These tables, which have been previously presented, are listed below:

Table	Description	Page
Table 5	Class Cost of Service Summary	18
Table 6	Class Cost of Service - Class Allocation Summary	18
Table 7	Class Cost of Service - Rate Design Factors	19

5.2 Rate Implementation Plan Factors

At the outset, it should be noted that there are many legitimate objectives that influence the design of rates. Some of the more important ones are as follows:

1. The proposed rates must develop the requisite total revenue.
2. The proposed rates should reflect the cost of providing service. No class or subclass should subsidize or be subsidized by another.
3. The rate schedules should be simple and concise to facilitate consumer acceptance and administration.
4. Abrupt departures from historical rate practices and levels should be avoided.
5. The rate structure should be acceptable to the membership.
6. Where there is a possibility of a consumer being eligible to receive service under more than one rate schedule, the transition should be made as smoothly as possible.
7. The rates should promote the efficient use of energy and system capacity.

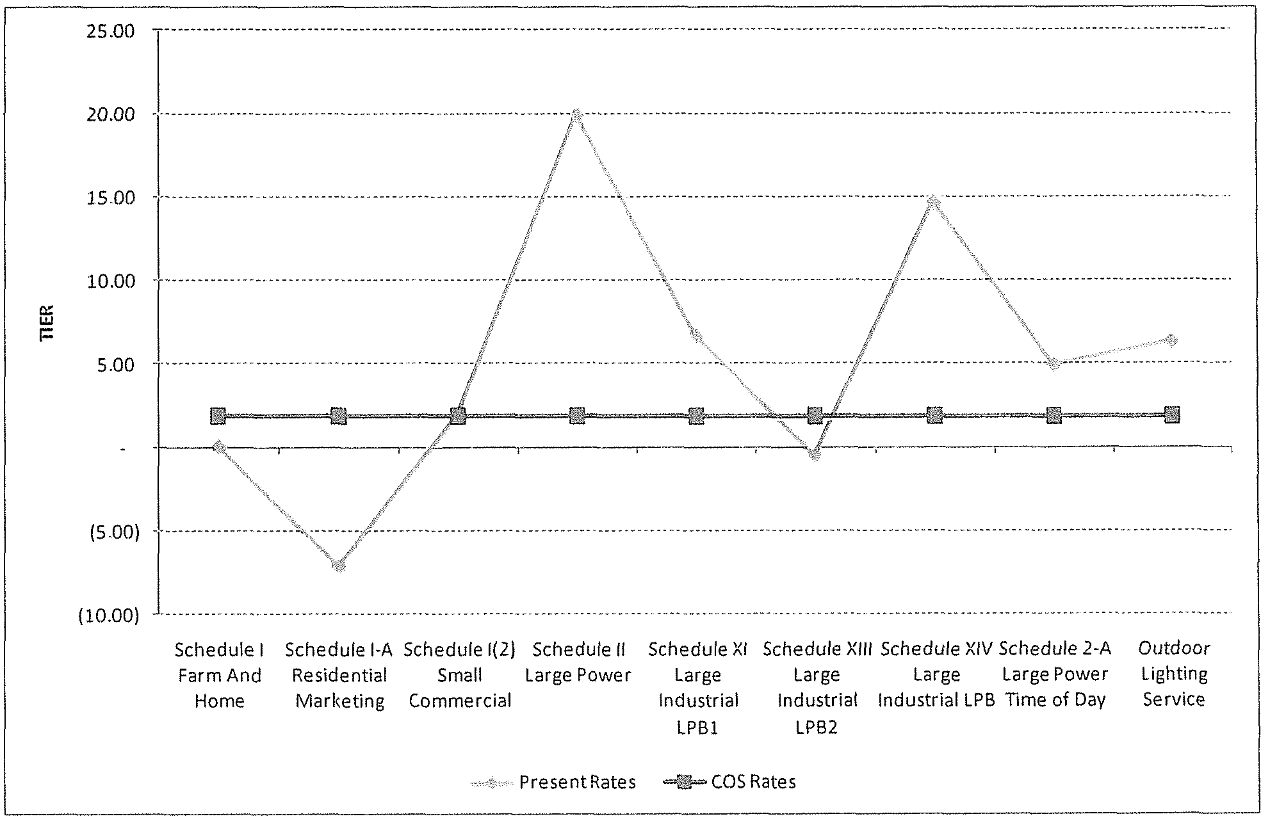
8. Whenever possible, the rate schedule should be competitive with those of neighboring utilities and alternative energy sources.

It is generally not possible to fully accomplish all of the above objectives in developing rate schedules. Compromises based on judgment reflecting the policy of the Cooperative must be made.

Three key factors addressed in this study that we recommend the Cooperative consider during future rate setting activities are: 1) COS results versus present rate design, 2) impact of proposed EKPC wholesale rates and 3) EISA considerations and TOU rates.

COS Results Versus Present Rate Design

The COS analysis is used to evaluate the present rate design in terms of cost recovery by rate schedule and in terms of rate structure design. In general, it is concluded that the Cooperative's residential service rate(s) are under-recovering while the commercial service rates are over-recovering, assuming a uniform M-TIER target requirement. The following chart demonstrates the M-TIER achieved by rate schedule based on the Test Year under present rates.



It is unlikely that these cross-class subsidies could be eliminated during the course of one rate change, even if that were desirable. The consumer bill impact often times limits the extent to which cross-class subsidies can be addressed during a given rate case.

It is also concluded, not surprisingly, that the COS determined consumer costs exceed the Cooperative's present customer charge. The following Table 9 compares the Cooperative's present customer charge with the COS results with and without the primary line consumer-component.[6]

Table 9
Comparison of Customer Charge and COS Results

Rate Class	Present Rate	COS Result	COS w/o Primary Line
	($/cons./mo.)	($/cons./mo.)	($/cons./mo.)
Residential Service	$10.87	$30.87	$18.70

[6] It is useful to consider the COS consumer cost result both with and without primary line (i.e., distribution backbone) related consumer costs since some utilities and/or commissions do not put such costs into the consumer cost category or rate.

There is a significant gap between the COS determined consumer-related costs and the present customer charge of the Cooperative. As previously listed, there are other rate setting objectives that must be weighed when considering a rate design change. Increasing the customer charge tends to be a very contentious issue during a regulated rate case with the commission and consumer advocacy groups resisting increases. The opposition to increasing customer charges often relates to the magnitude of the increase being proposed, as it is generally acknowledged that a customer charge in the $10 per month range does not recover the consumer-related fixed costs of a rural electric cooperative.

As part of establishing an overall rate setting strategy to guide future decisions, we suggest that the Cooperative consider the following.

1. Establish rate class maximum and/or minimum increase levels during a rate application:
    a. Set based on a multiple of the system average; i.e., 2x's.
    b. Set a maximum increase for any rate class; i.e., 15 percent.
    c. Determine how to handle rate decreases during an overall increase and vice versa.
    d. Combination of the above.
2. Determine M-TIER bandwidth (1.5 to 2.5 M-TIER) and a plan for getting each rate class within this maximum and minimum M-TIER bandwidth.
3. Develop a plan for increasing the customer charges in the direction of the COS results. Set maximum increase limits to prevent rate shock for low-usage customers.
4. Set a goal of recovering non-primary line consumer-related costs in the customer charge within 5 or 7 years.
5. Monitor the level of the demand charge for consumers with demand charge billing. With the expectation that future rate design changes from EKPC will result in increased demand versus energy charges, it is recommended that the Cooperative consider whether its retail demand charges will also need to be increased. It has been determined that, for at least some of the Cooperative's rates, the present demand charge is below the COS determined level. This results in demand-related costs being recovered in energy charges, which causes higher than average load factor customers to subsidize lower than average load factor customers.

6. Develop an alternative commercial and industrial rate design for coincidental demand billing. Such a rate design, when coordinated with EKPC, can prove to be a mutually beneficial demand-side management (DSM) program.
7. Explore the viability of a residential critical peak rate offering.

Impact of Proposed EKPC Wholesale Rates

The attached Exhibit 6 provides a comparison of the Cooperative's COS under the present and proposed wholesale rates for EKPC. The design of EKPC's wholesale rate can drive the design of the Cooperative's retail rate. For example, if EKPC were to tilt its rate design to dramatically increase demand costs, there would be implications on 1) the allocation of costs to the Cooperative's retail rate classes, 2) the level of retail demand and energy charges and 3) retail DSM programs and economics.

Based on the proposed wholesale rates for EKPC, the magnitude of cost shifting between the EKPC Members, retail rate classes and retail rate structures is fairly insignificant. The proposed EKPC wholesale rate places somewhat more emphasis on the demand charge versus energy charge primarily because of the rolling in of the ESR into the base rates. This tends to benefit the higher than average load factor and/or lower than average coincidence factor rate classes which is generally descriptive of the non-residential rate classes. Again, the impact is not significant but would tend to put some additional pressure on the future need to increase residential rates and demand charges in demand-billed rate classes.

The wholesale rate change proposed for EKPC does not materially affect the viability or structure of any existing or potential DSM activities for the Cooperative. The increased demand charge provides a slightly higher incentive to promote programs that target peak clipping such as cycled air conditioning or interrupting water heaters, but not significantly. It also will tend to result in a higher on-peak to off-peak retail rate differential if such a rate is to be offered, which will be discussed further below.

EISA and TOU Rates

On December 19, 2007, President Bush signed into law the Energy Independence and Security Act of 2007 (EISA). EISA includes, among other things, a section specifically targeting the electric industry; namely, Title V - Energy Savings in Government and Public Institutions, Subtitle D, Utility Energy Efficiency Programs. This section of EISA modifies Title I of PURPA of 1978, which requires covered electric utilities and/or regulatory bodies to consider a number of "rate design" standards such as cost of service, master metering, time-of-use rates, etc. EISA adds four new standards to be considered.

In the case of regulated electric utilities, such as EKPC and its Member-Systems, the authority for "consideration" of the standards is assigned to the state regulatory body, in this case the Kentucky Public Service Commission (Kentucky PSC). The Kentucky PSC opened an administrative proceeding in 2008 to consider these standards; however, no final decision of the standards has been issued by the PSC.

Title I of PURPA sets forth three purposes for implementing the rate design standards including:

1. Conservation of energy supplied by electric utilities;
2. The optimization of the efficiency and use of facilities and resources by electric utilities; and
3. Equitable rates to electric customers.

The final determination of action to take on each EISA rate design standard is to be based on these three purposes or objectives of PURPA. However, the language of EISA can be confusing unless read in conjunction with the original PURPA language. For example, one of the provisions is stated as follows:

> "Each electric utility <u>shall</u> integrate energy efficiency resources into utility, State, and regional plans; and adopt policies establishing cost-effective energy efficiency as a priority resource."

This language makes it appear that electric utilities covered by EISA must ("shall") adopt this standard. Actually, the language of the legislation points back to PURPA Title I which requires covered utilities to "consider" adopting such a standard. There is no requirement that the covered utilities actually adopt such a standard, but instead a covered utility or regulatory body may:

- Accept a standard;
- Reject a standard;

- Modify a standard; or
- Defer implementation of a standard.

The decision, of course, must be based on the evidence on the record for this deliberation, and the rationale for the decision on each standard must be documented in writing.

The four new "rate design" standards to be considered under EISA are:

1. The inclusion of the consideration of energy efficiency in the Integrated Resource Planning (IRP) process;
2. The adoption of rate design modifications to promote EE investments;
3. The consideration of smart grid investments in lieu of other system improvements; and
4. The provision of energy price and other information to consumers.

Two of the four new standards, the second and fourth, relate to rate design. The second standard requires consideration of a rate design approach which aligns incentives from the perspective of the utility with the delivery and promotion of cost-effective energy efficiency programs and investments. This standard is stated as follows:

> (2) *Rate Design modifications to Promote Energy Efficiency Investments*. (A) IN GENERAL - the rates allowed to be charged by any electric utility shall (I) align utility incentives with the delivery of cost-effective energy efficiency; and (II) promote energy efficiency investments. (B) POLICY OPTIONS - In complying with subparagraph (A), each utility shall consider (I) removing the throughput incentive and other regulatory and management disincentives to energy efficiency; (II) providing utility incentives for the successful management of energy efficiency programs; (III) including the impact on adoption of energy efficiency as one of the goals of retail rate design, recognizing that energy efficiency must be balanced with other objectives; (IV) adopting rate designs that encourage energy efficiency for each customer class; (V) allowing timely recovery of energy efficiency related costs; and (VI) offering home energy audits, offering demand response programs, publicizing the financial and environmental benefits associated with making home energy efficiency improvements, and educating homeowners about all existing Federal and State incentives, including the availability of low-cost loans, that make energy efficiency improvements more affordable.

This standard requires consideration of a variety of rate design related measures intended to promote energy efficiency, including:

1. Removing the throughput incentive and other regulatory and management disincentives to energy efficiency;
2. Providing utility incentives for the successful management of energy efficiency programs;
3. Including the impact on the adoption of energy efficiency as one of the goals of retail rate design, recognizing that energy efficiency must be balanced with other objectives;
4. Adopting rate designs that encourage energy efficiency for each customer class;
5. Allowing timely recovery of energy efficiency related costs;

(The sixth measure (i.e., offering home audits, etc.) goes beyond the rate design venue.)

A number of these measures seek to align the utility's self interest with the objective of energy efficiency. The issue being addressed here is the natural tendency of most utilities to seek to sell more energy. For an investor-owned utility, more energy generally equates with higher profits, while cooperatives tend to think of increased sales in terms of spreading their fixed costs over more kilowatt-hours, thereby reducing overall rates. The problem with energy efficiency is that it is often perceived as working against the overall objectives of the utility; and thus, this standard seeks to find a way to align the interests of the utility with the goals of energy efficiency.

One way of accomplishing this is to "decouple" revenue from energy sales; but that is generally easier said than done. For example, one could decrease the energy charge at the margin, which would reduce the revenue loss due to decreased energy sales. However, while that might reduce the disincentive from the utility's perspective, it would also diminish the incentive from the customer's perspective to participate in energy efficiency programs. Another approach that has been tried is to provide a regulatory rate of return incentive which rewards utilities for their success in promoting and achieving energy efficiency objectives. However, this approach is often viewed by non-profit cooperatives as a disincentive as it runs counter to the cooperatives' fundamental objective of keeping rates as low as possible. Another approach would be to develop an automatic adjustment clause, similar in some respects to a traditional fuel cost adjustment (FCA) clause, to track the loss in revenue that accompanies decreasing sales; but this can be very complex and difficult to implement. After discussions with EKPC's staff, we have concluded that there is little enthusiasm on the part of EKPC and/or its Member-Systems to adopt such an automatic adjustment mechanism.

The fourth measure in the foregoing list seeks to incorporate EE incentives in the design of retail rates. EKPC's wholesale rates clearly form the base for the design of the Member retail rates. We believe that adopting the Equivalent Peaker methodology, which inherently will shift cost recovery from the demand charge to the energy charge (in comparison to a rate design based on assigning 100 percent of production plant investment to the capacity component), goes a long way toward promoting EE without greatly diminishing the Member perceived benefits of direct load control (DLC).

The fourth standard provides 1) that electricity customers should be given direct written or electronic access to information concerning time-based electricity prices at wholesale and retail and their usage on at least a daily basis and 2) that everyone should have access to data concerning the sources of the power provided by the utility, including the greenhouse gas emissions associated with each type of generation. It reads as follows:

> (4) *Smart Grid Information.* (A) INFORMATION. - All electricity purchasers shall be provided direct access, in written or electronic machine-readable form as appropriate, and to the extent practicable, to the following information from their electricity provider: (I) PRICES. - time-based electricity prices in the wholesale electricity market, and time-based electricity prices or rates that are available to the purchasers; (II) USAGE. - Purchasers shall be provided with the number of electricity units, expressed in kwh, purchased by them; (III) INTERVALS AND PROJECTIONS. - Updates of information on prices and usage shall be offered on not less than a daily basis, shall include hourly price and use information, where available, and shall include a day-ahead projection of such price information to the extent available; and (IV) SOURCES. - Purchasers and other interested persons shall be provided annually with written information on the sources of the power provided by the utility, to the extent it can be determined, by type of generation, including greenhouse gas emissions associated with each type of generation, for intervals during which such information is available on a cost-effective basis. (B) ACCESS. - Purchasers shall be able to access their own information at any time through the Internet and on other means of communication elected by that utility for Smart Grid applications. Other interested persons shall be able to access information not specific to any purchaser through the Internet. Information specific to any purchaser shall be provided solely to that purchaser.

In terms of wholesale rates, the TOU aspect of EKPC's rate structure is one way EKPC has historically complied with this objective. In addition, EKPC is in the process of implementing a pilot real time pricing program to evaluate the effectiveness of this rate design approach. This program began on January 1, 2010, and is expected to continue for three years. In addition, as smart grid technology advances, EKPC's Member's are expected to upgrade their metering capabilities. This will likely lead to further rate design innovation and more sophisticated information systems to provide price signals that reflect real or near real time information to consumers.

It is our understanding that two EKPC Members have implemented retail residential TOU rates. During our discussion with each of the EKPC Members, a number of others indicated their interest and/or intentions of also considering retail TOU rates.

TOU Rates

Around the country and within EKPC's membership, there is a growing interest in TOU rates. Reasons for this include: 1) encouraging efficient use of resources, 2) charging equitable rates and 3) decreasing technological barriers due to the deployment of smart meters. A TOU rate most commonly includes a two- or three-part TOU energy charge structure for on-peak, off-peak and sometimes shoulder peak consumption. When designed properly, a TOU provides for 1) an equitable (i.e., cost of service based) rate design and 2) an appropriate price signal for consumers.

The justification for a TOU rate lies in capturing and billing peak-related costs during peak times. Within that framework, there are endless ways cooperatives can design and structure TOU rates in terms of seasonality, time period definitions, day of week, holidays, number of on-peak periods, shoulder peaks, etc. It is important that the design of the rate balance the sometimes competing goals of reflecting cost of service, providing accurate price signals and being easy for customers to understand and respond to. An overly complex TOU rate may meet the first two of those objectives; but if customers cannot connect the dots between how their lifestyle or consumption choices affect their bill, the rate will not achieve its potential.

Generally, TOU rates are offered as optional rates. As such, there are customers of the Cooperative that have favorable usage profiles currently that would benefit from an optional TOU rate without making usage behavioral changes. This is known as the "free rider" issue and must be considered and ideally evaluated by the Cooperative if an optional TOU rate offering is being considered. In some circumstances, this potential revenue and margin reduction can be absorbed easily by the Cooperative. It may also be justified in that the customers benefitting are so benefitting because they are relatively more off peak than the class upon which their present non-TOU rate is based; i.e., the benefits are cost justified. The Cooperative may in fact choose to recover the lost revenue/margins through increasing the non-TOU rate, a process that would provide incentive for incrementally more consumers to move to the TOU rate.

Example Residential TOU rates have been developed for the Cooperative in Exhibit 8. This includes four revenue-neutral rate design examples. By revenue neutral, it is meant that if all the residential consumers moved to the residential TOU rate and maintained pre-existing usage behaviors, the revenue generated by the standard residential and residential TOU rates would match. The design would allow for bill reductions to consumers and wholesale power cost reductions to the Cooperative for shifts in consumption from on-peak to off-peak periods.[7]

The Residential TOU rates are developed under two TOU definitions. First, TOU periods were defined consistent with the EKPC wholesale rate definition, which does not change under the proposed EKPC rate design. Within this scenario (see page 1 of Exhibit 8), we have developed two sets of TOU energy charges. The first captures power supply capacity and energy costs in the on-peak energy charge. The second goes a step further and also recovers peak-related distribution costs in the on-peak energy charge.[8]

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7 An inherent limitation of TOU rates is that there is no guarantee that the consumption shifting will affect the load during the time of the coincident peak of the power supplier. A critical peak or coincident peak rate is an example of a rate design that better targets load during the power supply peak events.

8 It could be argued that peak-related distribution costs are fixed and that the on-peak price signal should thus not allow for avoiding these costs.

The Cooperative could implement a TOU rate with a more narrowly defined on-peak period than EKPC's wholesale rate definition. In doing this, it is important to consider whether the more narrowly defined on-peak definition will still capture the power supply peaks; or, if not, to what extent some power supply peak costs need to be captured in off-peak energy charges. In the second scenario, we have utilized a narrower on-peak definition that is based on the TOU definition of Blue Grass Energy. While this on-peak definition is narrower than that of EKPC, it would still have captured all of the 2009 power supply billing peaks.

Schedule A
Summary of Consumers, Energy Sales, and Revenue Under Present Rates

I. Consumer and Sales Data for the Pro Forma Test Year

(a) Line No.	(b) Description	(c) Avg. No. Cons. [1]	(d) Energy Sales [1]	(e) Billing Demand [1] Non-Coinc.	(f) Coinc.	(g) Actual Revenue [1]	(h) Pro Forma Revenue [2]
			(kWh)	(kW)	(kW)	($)	($)
1	Schedules I: Farm and Home	54,076	710,449,061	NA	NA	70,124,670	70,045,555
2	Schedules I-A: Residential Marketing	8	27,641	NA	NA	1,527	1,363
3	Schedule I: Small Commercial	2,294	46,652,046	NA	NA	4,508,357	4,478,861
4	Schedule II: Large Power	250	177,917,564	557,060.0	NA	15,411,323	14,999,519
5	Schedule 5: Renewable Resource Power			NA	NA	-	
6	Schedule III: Security Lights	9,345	6,372,258	NA	NA	829,843	989,719
7	Schedule XI: Large Industrial LPB1	9	67,594,969	146,008.0	NA	4,947,049	4,757,501
8	Schedule XIII: Large Industrial Rate LPB2	2	109,933,836	188,885.0	NA	6,235,632	6,485,816
9	Schedule XIV: Large Industrial Rate LPB	4	10,883,375	28,527.0	NA	961,330	881,267
10	Schedule I OLS: Outdoor Lighting Service	3,327	1,692,936	NA	NA	416,888	455,908
11	Schedule II SOLS: SpecialOutdoor Lighting	480	228,904	NA	NA	62,465	82,318
12	Schedule III SOLS: SpecialOutdoor Lighting			NA	NA		-
13	Schedule 2-A: Large Power - Time of Day	9	3,633,704	NA	NA	300,985	306,759
14	Gallatin Contract	1	858,526,147	1,706,527.0	NA	35,984,650	41,103,803
15	**Total** [3]	56,645	1,993,912,441	2,627,007.0	-	139,784,719	144,588,388

[1] As reported by the Cooperative for 2009.
[2] See Schedule A, pages 3 - 5.
[3] The total number of consumers excludes number of Outdoor Lighting Service and Residential Marketing.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
Schedules I: Farm and Home				
Customer Charge	54,076	/month	$10.87	7,053,630
Energy Charge	710,449,061	/kWh	$0.09126	64,835,581
Fuel Charge	710,449,061	/kWh	($0.00831)	(5,900,626)
Environmental Surcharge			6.1%	4,056,970
				70,045,555
Schedules I-A: Residential Marketing				
Energy Charge	27,641	/kWh	$0.05476	1,514
Fuel Charge	27,641	/kWh	($0.00831)	(230)
Environmental Surcharge			6.1%	79
				1,363
Schedule I: Small Commercial				
Customer Charge	2,294	/month	$12.83	353,184
Energy Charge	46,652,046	/kWh	$0.09118	4,253,734
Fuel Charge	46,652,046	/kWh	($0.00831)	(387,468)
Environmental Surcharge			6.1%	259,411
				4,478,861
Schedule II: Large Power				
Customer Charge	250	/month	$20.50	61,500
Energy Charge	177,917,564	/kWh	$0.06891	12,260,299
Demand Charge	557,060	/kW	$5.90	3,286,654
Fuel Charge	177,917,564	/kWh	($0.00831)	(1,477,692)
Environmental Surcharge			6.1%	868,757
				14,999,519
Schedule III: Security Lights				
120 Volts, where available	7,760	/month	$8.46	787,795
With 1 Pole Added	1,495	/month	$10.20	182,988
With 2 Pole Added	83	/month	$11.94	11,892
With 3 Pole Added	7	/month	$13.68	1,149
With 4 Pole Added	-	/month	$15.43	-
Transformer Charge	186	/month	$0.67	1,495
Fuel Charge	6,372,258	/kWh	($0.00831)	(52,925)
Environmental Surcharge			6.1%	57,324
	9,345			989,719
Schedule XI: Large Industrial LPB1				
Customer Charge	9	/month	$1,464.04	162,508
Energy Charge - 425 Hrs per kW	61,090,580	/kWh	$0.05446	3,326,993
Energy Charge - Over 425 Hrs per kW	6,504,389	/kWh	$0.05038	327,691
Demand Charge - Contract Demand	146,008	/kW	$6.81	994,314
Demand Charge - kW > Contract Demand	12,194	/kW	$9.47	115,477
Fuel Charge	67,594,969	/kWh	($0.00719)	(486,013)
Environmental Surcharge			7.1%	316,529
				4,757,501

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
Schedule XIII: Large Industrial Rate LPB2				
Customer Charge	2	/month	$2,927.05	70,249
Energy Charge - 425 Hrs per kW	83,036,690	/kWh	$0.04971	4,127,754
Energy Charge - Over 425 Hrs per kW	26,897,146	/kWh	$0.04813	1,294,560
Demand Charge - Contract Demand	195,900	/kW	$6.81	1,334,079
Demand Charge - kW > Contract Demand	1,910	/kW	$9.47	18,088
Fuel Charge	109,933,836	/kWh	($0.00719)	(790,432)
Environmental Surcharge			7.1%	431,519
				6,485,816
Schedule XIV: Large Industrial Rate LPB				
Customer Charge	4	/month	$1,464.00	70,272
Energy Charge	10,883,375	/kWh	$0.05600	609,469
Demand Charge - Contract Demand	28,527	/kW	$6.81	194,269
Demand Charge - kW > Contract Demand	2,838	/kW	$9.47	26,876
Fuel Charge	10,883,375	/kWh	($0.00719)	(78,252)
Environmental Surcharge			7.1%	58,633
				881,267
Schedule I OLS: Outdoor Lighting Service				
100 Watt HPS Area	3,138	/month	$10.12	381,079
Cobrahead Lighting				
100 Watt HPS	25	/month	$13.05	3,915
250 Watt HPS	11	/month	$17.90	2,363
400 Watt HPS	20	/month	$22.63	5,431
Directional Lighting				
100 Watt HPS	27	/month	$12.24	3,966
250 Watt HPS	27	/month	$15.25	4,941
400 Watt HPS	77	/month	$19.73	18,231
Pole Charges	420	/month	$4.69	23,638
Fuel Charge	1,692,936	/kWh	($0.00831)	(14,061)
Environmental Surcharge			6.15%	26,406
				455,908
Schedule II SOLS: SpecialOutdoor Lighting				
Traditional Light W/ Fiberglass Pole	299	/month	$12.90	46,285
Holophane Light W/ Fiberglass Pole	181	/month	$15.27	33,166
Fuel Charge	228,904	/kWh	($0.00831)	(1,901)
Environmental Surcharge			6.15%	4,768
				82,318
Schedule III SOLS: SpecialOutdoor Lighting				
Facilities Charge (1.75 x total investment)		/month	$0.00	-
Energy Charge		/kWh	$0.063902	-
Fuel Charge		/kWh	($0.008305)	-
Environmental Surcharge			6.15%	0
				-
Schedule 2-A: Large Power - Time of Day				
Customer Charge	9	/month	$59.00	6,608
Energy Charge - On Peak	1,836,960	/kWh	$0.105948	194,622
Energy Charge - Off Peak	1,796,744	/kWh	$0.064171	115,299
Fuel Charge	3,633,704	/kWh	($0.0083055)	(30,180)
Environmental Surcharge			7.13%	20,409
				306,759

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
Special Contracts				
Gallatin				
Firm Demand	180,000.0	/kW	$6.63	1,193,400
10-Min Intter. Demand	1,426,898.0	/kW	$1.03	1,469,705
90-Min Interr. Demand	99,629.0	/kW	$2.43	242,098
Total Demand Charge	1,706,527.0			2,905,203
On-Peak Energy	211,869,199.0	/kWh	$0.04713	9,984,972
Off-Peak Energy	581,794,340.0	/kWh	$0.04384	25,508,191
Min. Energy On-Peak	18,804,206.0	/kWh	$0.01060	199,287
Min Energy Off-Peak	46,058,402.0	/kWh	$0.00731	336,871
Buy-Thru Chg, Cr On-Pk				113,084
Buy-Thru Chg, Cr Off-Pk				10,798
Energy Charge				36,153,203
Load Following Charge				325,000
FAC Charge	858,526,147.0	/kWh	($0.00231)	(1,982,920)
Distribution Demand Charge	1,706,527.0		$0.03750	63,995
Distribution Energy Charge	858,526,147.0	/kWh	$0.00029	244,680
Environmental Surcharge			9.08%	3,394,642
				41,103,803

Schedule B
Estimate of Pro Forma Test Year Purchased Power Expense

(a) Line No.	(b) Description	(c) Units [1]		(d) Rate [2]		(e) Cost
1						($)
2	Metering Point Charge	25		$350.00		105,000
3	Substation Charge	25		$4,305.72		1,291,716
4	**Rate E1**					
5	Demand Charge [3]	2,194,036.0	kW	$7.38	/kW	16,191,986
6	Power Factor Penalty					11,301
7	Energy Charges					
8	On-Peak	515,341,871	kWh	$0.05655	/kWh	29,144,644
9	Off-Peak	484,561,322	kWh	$0.05055	/kWh	24,496,513
10				Total Energy Charges		53,641,157
11	Fuel Adjustment Charge	999,903,193	kWh	($0.00787)	/kWh	(7,865,082)
12						
13	Environmental Surcharge					-
14				Total Rate E		63,376,078
15						
16	**Rate B**					
17	Minimum Demand	288,148.0	kW	$7.25	/kW	2,089,073
18	Excess Demand	8,704.0	kW	$10.15	/kW	88,346
19	Total Demand [3]	296,852.0	kW			2,177,419
20	Interuptible Demand - Firm	82,383.0	kW	($4.90)	/kW	(403,677)
21	Interuptible Demand - Discount		kW	$0.00		-
22	Energy Charges	183,971,607	kWh	$0.05126	/kWh	9,430,385
23	Fuel Adjustment Charge	183,971,607	kWh	($0.007364)	/kWh	(1,354,697)
24	Environmental Surcharge					-
25				Total Rate B		9,849,429
26						
27	**Special Contracts**					
28	**Gallatin**					
29	Firm Demand	180,000.0	kW	$6.63	/kW	1,193,400
30	10-Min Intter. Demand	1,426,898.0	kW	$1.03	/kW	1,469,705
31	90-Min Interr. Demand	99,629.0	kW	$2.43	/kW	242,098
32	Total Demand Charge	1,706,527.0				2,905,203
33	On-Peak Energy	211,869,199.0	kWh	$0.04713	/kWh	9,984,972
34	Off-Peak Energy	581,794,340.0	kWh	$0.04384	/kWh	25,508,191
35	Min. Energy On-Peak	18,784,206.0	kWh	$0.01060	/kWh	199,075
36	Min Energy Off-Peak	52,058,402.0	kWh	$0.00731	/kWh	380,755
37	Buy-Thru Chg, Cr On-Pk					113,084
38	Buy-Thru Chg, Cr Off-Pk					10,798
39	Energy Charge					36,196,875
40	Load Following Charge					325,000
41	FAC Charge	864,506,147.0	kWh	($0.00229)	/kWh	(1,982,920)
42	Environ. Surchg			9.14%		3,422,659
43				Total Gallatin		40,866,817
44						
45	**Total Test Year Purchased Power Cost**	2,048,380,947	kWh	$0.05570	/kWh	$ 114,092,325

1 Billing units based on budget 2009

2 Purchased Power Rates are the Proposed rates for East Kentucky Power Cooperative.

3 Usage remains similar to 2009 usage.

Determination of Revenue Requirements - Summary
TIER Method

(a)	(b)	(c)	(d)
			Pro Forma Test Year
Line No.	Description	2009 Actual	Present Rates
Financial Results From Rates		($)	($)
1	Total Revenue [1]	141,746,616	146,462,557
2	Operating Expense [1]	140,319,392	144,410,269
3	Net Operating Income [2]	1,427,224	2,052,287
4	Non-Operating Income [3]	105,017	105,017
5	Income (Loss) from Equity Investments [3]	-	-
6	Other Capital Credits [3]	244,923	244,923
7	G&T Capital Credits [3]	3,551,381	3,551,381
8	Total Margin [4]	5,328,545	5,953,609
9	Rate of Return [5]	4.49%	4.95%
10	Operating TIER [6]	1.31	1.45
11	Modified TIER [7]	1.39	1.53
12	TIER [8]	2.17	2.30
Required Increase/(Decrease) --Modified TIER Objective			
13	Operating Expenses (excluding interest) [1]	135,754,418	139,845,295
14	Margin Requirements		
15	Interest Expense [3]	4,564,974	4,564,974
16	Target Modified TIER [9]	2.00	2.00
17	Total Margin Required (before interest) [10]	9,129,948	9,129,948
18	Less: Non-Operating Income [3]	105,017	105,017
19	Less: Income (Loss) from Equity Investments [3]	-	-
20	Less: Other Capital Credits [3]	244,923	244,923
21	Net Operating Income Required [11]	4,215,034	4,215,034
22	Total Revenue Requirements [12]	144,534,426	148,625,304
23	Revenue From Present Rates		
24	Tariff Revenue [1]	139,872,447	144,588,388
25	Other Operating Revenue [1]	1,874,169	1,874,169
26	Total Revenue [13]	141,746,616	146,462,557
27	Required Increase/(Decrease) [14]	2,787,810	2,162,747
28	Percent Increase/(Decrease) [15]	1.99	1.50

[1] See Exhibit 2.
[2] Line 1 minus Line 2.
[3] From year end Form 7.
[4] Sum of Lines 3 through 7
[5] Line 3 divided by Line 29 (on page 2).
[6] Sum of Lines 3 and 15 divided by Line 15
[7] Sum of Lines 3, 4, 5, and 15 divided by Line 15
[8] Sum of Lines 7 and 15 divided by Line 15
[9] As determined by Owen Electric Cooperative Inc..
[10] Line 15 times Line 16.
[11] Line 17 minus Lines 15 and 18 through 20.
[12] Line 13 plus Lines 15 and 21.
[13] Line 24 plus Line 25.
[14] Line 22 minus Line 26.
[15] Line 27 divided by Line 24.

Determination of Revenue Requirements Summary
Rate of Return Method
(Continued)

(a)	(b)	(c)	(d)
			Pro Forma Test Year
Line No.	Description	2009 Actual	Present Rates
Required Increase (Decrease) --ROR Objective		($)	($)
29	Operating Expense (excluding interest) [1]	135,754,418	139,845,295
30	Margin Requirements		
31	Rate Base [2]	135,757,983	135,757,983
32	Rate of Return [3]	6.09%	6.09%
33	Required Return [4]	8,267,378	8,267,378
34	Less: Non-Operating Income [5]	105,017	105,017
35	Net Operating Income Required [6]	8,162,360	8,162,360
36	Total Revenue Requirements [7]	143,916,778	148,007,656
37	Revenue Present Rates		
38	Tariff Revenue [1]	139,872,447	144,588,388
39	Other Operating Revenue [1]	1,874,169	1,874,169
40	Total Revenue [8]	141,746,616	146,462,557
41	Required Increase (Decrease) [9]	2,170,162	1,545,099
42	Percent Increase (Decrease) [10]	1.55	1.07

1 See Exhibit 3, Page 1.
2 See Exhibit 3, page 3.
3 See Exhibit 3, page 5.
4 Line 31 times Line 32.
5 See Exhibit 3, Page 1, Line 4 plus Line 5.
6 Line 33 minus Line 35.
7 Line 29 plus Line 35.
8 Line 38 plus Line 39.
9 Line 36 minus Line 40.
10 Line 41 divided by Line 38.

Schedule A
Rate Base

(a) Line No.	(b) Description	(c) Pro Forma Test Year
		($)
1	Utility Plant in Service [1]	204,255,817
2	Construction Work in Progress [1]	3,617,437
3	Less: Accumulated Provision for Deprec. [1]	75,981,487
4	Net Plant [1]	131,891,767
5	Materials & Supplies - Electric [2]	994,264
6	Prepayments [2]	475,528
7	Working Capital [3]	5,099,401
8	Subtotal	6,569,193
9	Less: Consumer Deposits [1]	2,702,977
10	**Total Rate Base**	135,757,983

1 December 31, 2009, Form 7 amount.

2 13 - Month Average. See Schedule B.

3 See Schedule B.

Schedule B
Rate Base Calculations
Materials & Supplies - Electric Prepayments

(a) Line No.	(b) Month		(c) Materials & Supplies Electric	(d) Prepayments
			($)	($)
1	Dec	2008	1,026,017	379,544
2	Jan	2009	1,051,392	713,270
3	Feb	2009	1,027,161	632,468
4	Mar	2009	989,029	544,589
5	Apr	2009	999,315	456,107
6	May	2009	928,362	390,187
7	Jun	2009	974,984	371,111
8	Jul	2009	961,130	504,117
9	Aug	2009	993,383	513,674
10	Sep	2009	1,024,777	434,575
11	Oct	2009	1,022,309	366,835
12	Nov	2009	956,292	335,363
13	Dec	2009	971,283	540,028
14	**Total**		12,925,435	6,181,867
15	**13 - Month Average**		994,264	475,528

Schedule B
Rate Base Calculations
Working Capital
(Continued)

(a) Line No.	(b) Description	(c) Weight Factor	(d) Pro Forma Test Year Total Amount	(e) Pro Forma Test Year Weighted Amount
			($)	($)
1	Purchased Power	10/365	114,092,325	3,125,817
2	Other O&M Exp.			
3	Dist. Oper.		5,379,575	
4	Dist. Main.		3,863,514	
5	Cons. Acct.		3,427,328	
6	Cons. Serv.		559,353	
7	Sales		-	
8	Admin. & Gen.		2,778,189	
9	**Subtotal**	45/365	16,007,958	1,973,584
10	**Total Working Capital**			5,099,401

Schedule C
Composite Cost of Capital
and Rate of Return

(a) Line No.	(b) Description	(c) Interest Rate	(d) Estimated Balance	(e) Annualized Interest Expense [1]	(f) Actual Percent of Total	(g) Cost of Capital	(h) Weighted Cost of Capital
	Long Term Debt	(%)	($)	($)	(%)	(%)	(%)
1	RUS	5.38%	1,396,119	75,041			
2	RUS	4.37%	1,292,753	56,493			
3	RUS	4.46%	12,952,131	577,665			
4	RUS	4.19%	6,972,821	292,161			
5	RUS	4.44%	8,921,842	396,130			
6	RUS	3.62%	1,443,033	52,238			
7	RUS	0.50%	1,450,461	7,252			
8	CFC [2]	5.64%	24,172,174	1,363,211			
9	FFB [3]	5.40%	35,600,223	1,921,593			
10	Total Long Term Debt		94,201,556	4,741,785	61.8	5.03	3.11
11	Equity [4]		58,254,456		38.2	7.80 [5]	2.98
12	Total LT Debt and Equity		152,456,012		100.0		
13	**Required Rate of Return**						6.09

[1] The Annualized Interest Expense is based on the Estimated Loan Balance multiplied by the loan interest rate.

[2] Represents Total CFC Loans and a weighted average interest rate.

[3] Represents Total FFB Loans and a weighted average interest rate.

[4] Data taken from RUS Form 7 for December 31, 2009.

[5] See Schedule E.

Schedule D
Growth Rate Calculation

(a) Line No.	(b) Year	(c) Net Plant [1]
		($)
1	2004	105,007,231
2	2005	109,777,890
3	2006	118,455,515
4	2007	126,414,703
5	2008	129,616,048
6	2009	131,891,767

The mean growth rate in Net Plant is estimated to be:

2004-2009 = 4.66%

[1] Net Plant figures are from the utility's RUS Form 7 for the years listed.

Schedule E
Cost of Equity Capital

1. Criteria & Cooperative Policy

a. Rotate capital credits on a 20 year cycle based on the Cooperative's policy.

b. Annual growth rate = 4.66%
(See Schedule D)

2. Calculation of Return on Equity Capital

$$R = \frac{(1+g)^{n+1} - (1+g)^{n}}{(1+g)^{n} - 1}$$

WHERE: R = rate of return on equity
n = number of years in rotation period
g = growth rate

$$R = \frac{1.0466^{21} - 1.0466^{20}}{1.0466^{20} - 1} = 7.80\%$$

Cost of Service Summary

Revenue Requirements Summary -- BUNDLED

Line No.	Description	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
1	**Revenue Requirements**										
2	Revenue Requirements	107,521,502	77,892,192	2,278	4,529,674	11,613,294	4,349,374	6,968,562	684,629	290,370	1,191,129
3											
4	**Present Rates**										
5	Revenue-Present Rates	103,484,586	70,045,555	1,363	4,478,861	14,999,519	4,757,501	6,485,816	881,267	306,759	1,527,945
6	Revenue Credits	1,874,169	1,268,568	25	81,115	271,650	86,161	117,462	15,960	5,556	27,672
7		105,358,755	71,314,123	1,388	4,559,976	15,271,169	4,843,662	6,603,278	897,227	312,315	1,555,617
8											
9	Difference	2,162,747	6,578,069	890	(30,302)	(3,657,875)	(494,288)	365,284	(212,598)	(21,944)	(364,488)
10	As Percent	2.1%	9.4%	65.3%	(0.7%)	(24.4%)	(10.4%)	5.6%	(24.1%)	(7.2%)	(23.9%)

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Cost of Service Summary
Class Allocation Summary – BUNDLED

Line No.	Category	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
20	**Power Supply**										
21	Direct and Revenue Related										
22	Wholesale Cost										
23	Allocated Cost										
24	Subtotal										
25	Capacity Related										
26	Wholesale Cost	17,977,029	13,830,293		775,401	1,356,233	712,620	921,890	139,232	49,184	192,176
27	Allocated Cost										
28	Subtotal	17,977,029	13,830,293		775,401	1,356,233	712,620	921,890	139,232	49,184	192,176
29	Energy Related										
30	Wholesale Cost	53,851,763	34,332,398	1,226	2,262,340	8,640,611	2,856,307	4,804,171	415,210	176,472	363,028
31	Allocated Cost										
32	Subtotal	53,851,763	34,332,398	1,226	2,262,340	8,640,611	2,856,307	4,804,171	415,210	176,472	363,028
33	Sub. Power Supply	71,828,792	48,162,691	1,226	3,037,740	9,996,844	3,568,927	5,726,061	554,442	225,656	555,204
34	**Transmission**										
35	Direct										
36	Capacity										
37	Energy										
38	Allocated Cost										
39	Sub. Transmission										
40	**Distribution**										
41	Direct	12,285									12,285
42	Consumer	21,719,241	20,033,173	666	849,843	300,179	14,836	3,297	6,594	23,421	487,233
43	Capacity	13,961,183	9,696,328	385	642,091	1,316,270	765,611	1,239,204	123,594	41,293	136,406
44	Energy										
45	Sub. Distribution	35,692,710	29,729,500	1,051	1,491,934	1,616,450	780,447	1,242,501	130,187	64,714	635,925
46											
47	**Total**	107,521,502	77,892,192	2,278	4,529,674	11,613,294	4,349,374	6,968,562	684,629	290,370	1,191,129

Cost of Service Summary
Rate Design Factors – BUNDLED

Line No.	Category	Units	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
48	**Costs Broken Down by Function**											
49	**Power Supply**											
50	Direct and Revenue Related											
51	Wholesale Cost	¢/kWh										
52	Allocated Cost	¢/kWh										
53	Subtotal											
54	Capacity Related	¢/kWh										
55	Wholesale Cost	¢/kWh	1.58	1.95		1.66	0.76	1.05	0.84	1.28	1.35	2.32
56	Allocated Cost	¢/kWh										
57	Subtotal		1.58	1.95		1.66	0.76	1.05	0.84	1.28	1.35	2.32
58	Energy Related	¢/kWh										
59	Wholesale Cost	¢/kWh	4.74	4.83	4.44	4.85	4.86	4.23	4.37	3.82	4.86	4.38
60	Allocated Cost	¢/kWh										
61	Subtotal	¢/kWh	4.74	4.83	4.44	4.85	4.86	4.23	4.37	3.82	4.86	4.38
62	Sub. Power Supply		6.33	6.78	4.44	6.51	5.62	5.28	5.21	5.09	6.21	6.69
63	**Transmission**	¢/kWh										
64	Direct	¢/kWh										
65	Capacity	¢/kWh										
66	Energy	¢/kWh										
67	Allocated Cost	¢/kWh										
68	Sub. Transmission											
69	**Distribution**	$/Mo./cons										
70	Direct	$/Mo./cons	0.02									0.08
71	Consumer	¢/kWh	31.95	30.87	6.94	30.87	100.06	137.37	137.37	137.37	216.86	3.09
72	Capacity	¢/kWh	1.23	1.36	1.39	1.38	0.74	1.13	1.13	1.14	1.14	1.64
73	Energy	¢/kWh										
74	Sub. Distribution	¢/kWh	3.14	4.18	3.80	3.20	0.91	1.15	1.13	1.20	1.78	7.67
75	Total		9.47	10.96	8.24	9.71	6.53	6.43	6.34	6.29	7.99	14.36
76	**Costs Broken Down by Classification**	¢/kWh										
77	Direct	$/Mo./cons	0.00									0.15
78	Consumer	¢/kWh	31.95	30.87	6.94	30.87	100.06	137.37	137.37	137.37	216.86	3.09
79	Capacity	¢/kWh	2.81	3.31	1.39	3.04	1.50	2.19	1.97	2.41	2.49	3.96
80	Energy		4.74	4.83	4.44	4.85	4.86	4.23	4.37	3.82	4.86	4.38
81	Total		9.47	10.96	8.24	9.71	6.53	6.43	6.34	6.29	7.99	14.36

Classification of Plant in Service – BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
1		**Intangible Plant**																
2	301	Organization	PLNT															
3	302	Franchises and consents	PLNT															
4	303	Miscellaneous intangible plant	PLNT															
5	301-303	Subtotal																
6																		
7		**Production Plant**																
8	310-346	Production Plant	PROD1															
9																		
10		**Transmission Plant**																
11	350-359	Transmission Plant	TRAN2															
12																		
13		**Distribution Plant**																
14	360	Land	LAND															
15	361	Structures	SUB															
16	362	Station	SUB	281,416					281,416									
17	363	Battery	SUB															
18	364	Poles, towers	PRI-OH	51,381,498							26,075,967	25,305,531						
19	365	OH Cond	PRI-OH	37,592,766							19,078,224	18,514,542						
20	366	UG Conduit	PRI-UG															
21	367	UG Cond	PRI-UG	26,756,464							18,520,033	8,236,431						
22	368	Transf	TRF	25,036,362									10,187,308	14,849,054				
23	369	Services	SERV	18,072,677											18,072,677			
24	370	Meters	MTR	16,001,709												16,001,709		
25	371	Cons Premise	ICON	5,247,187							2,662,933	2,584,254						
26	372	Leased Prop	LICON															
27	373	St. Light	STL	123,773														
28	360-373	Subtotal		180,493,852					281,416		66,337,157	54,640,758	10,187,308	14,849,054	18,072,677	16,001,709		
29																		
30		**General Plant**																
31	389	Land & Land Rights	PLNT	2,259,072					3,522		830,280	683,887	127,505	185,852	226,199	200,278		
32	390	Structures and Improve.	PLNT	9,883,594					15,410		3,632,531	2,992,052	557,843	813,114	989,635	876,231		
33	391	Office Furniture & Equip.	PLNT	2,452,348					3,824		901,315	742,397	138,414	201,752	245,551	217,413		
34	392	Transportation & Equipment	PLNT	5,012,927					7,816		1,842,408	1,517,559	282,936	412,409	501,940	444,422		
35	393	Stores Equipment	PLNT	208,367					325		76,581	63,079	11,761	17,142	20,864	18,473		
36	394	Tool, Shop & Garage Equip.	PLNT	301,014					469		110,632	91,126	16,990	24,764	30,140	26,686		
37	395	Laboratory Equipment	PLNT	363,436					567		133,574	110,023	20,513	29,900	36,390	32,220		
38	396	Power Operated Equipment	PLNT	199,181					311		73,205	60,298	11,242	16,386	19,944	17,658		
39	397	Communication Equipment	PLNT	2,907,088					4,533		1,068,446	880,060	164,080	239,163	291,084	257,728		
40	398	Miscellaneous Equipment	PLNT	125,966					196		46,296	38,134	7,110	10,363	12,613	11,168		
41	399	Other tangible property	PLNT	48,973					76		17,999	14,826	2,764	4,029	4,904	4,342		
42	389-399	Subtotal		23,761,966					37,048		8,733,268	7,193,441	1,341,156	1,954,874	2,379,263	2,106,621		
43																		
44		**Total Plant**		204,255,818					318,464		75,070,425	61,834,199	11,528,465	16,803,927	20,451,940	18,108,330		

Classification of Plant in Service – BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Schedule I Farm And Home Direct	Schedule I-A Residential Marketing Direct	Schedule I(2) Small Commercial Direct	Schedule II Large Power Direct	Schedule XI Large Industrial LPB1 Direct	Schedule XIII Large Industrial LPB2 Direct	Schedule XIV Large Industrial LPB Direct	Schedule 2-A Large Power Time of Day Direct	Outdoor Lighting Service Direct
1		**Intangible Plant**											
2	301	Organization	PLNT										
3	302	Franchises and consents	PLNT										
4	303	Miscellaneous intangible plant	PLNT										
5	301-303	Subtotal											
6													
7		**Production Plant**											
8	310-346	Production Plant	PROD1										
9													
10		**Transmission Plant**											
11	350-359	Transmission Plant	TRAN2										
12													
13		**Distribution Plant**											
14	360	Land	LAND										
15	361	Structures	SUB										
16	362	Station	SUB	281,416									
17	363	Battery	SUB										
18	364	Poles, towers	PRI-OH	51,381,498									
19	365	OH Cond	PRI-OH	37,592,766									
20	366	UG Conduit	PRI-UG										
21	367	UG Cond	PRI-UG	26,756,464									
22	368	Transf	TRF	25,036,362									
23	369	Services	SERV	18,072,677									
24	370	Meters	MTR	16,001,709									
25	371	Cons Premise	ICON	5,247,187									
26	372	Leased Prop	LICON										
27	373	St. Light	STL	123,773									123,773
28	360-373	Subtotal		180,493,852									123,773
29													
30		**General Plant**											
31	389	Land & Land Rights	PLNT	2,259,072									1,549
32	390	Structures and Improve.	PLNT	9,883,594									6,778
33	391	Office Furniture & Equip.	PLNT	2,452,348									1,682
34	392	Transportation & Equipment	PLNT	5,012,927									3,438
35	393	Stores Equipment	PLNT	208,367									143
36	394	Tool, Shop & Garage Equip.	PLNT	301,014									206
37	395	Laboratory Equipment	PLNT	363,436									249
38	396	Power Operated Equipment	PLNT	199,181									137
39	397	Communication Equipment	PLNT	2,907,088									1,994
40	398	Miscellaneous Equipment	PLNT	125,966									86
41	399	Other tangible property	PLNT	48,973									34
42	389-399	Subtotal		23,761,966									16,295
43													
44		**Total Plant**		204,255,818									140,068

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Classification of Revenue Requirements – BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
1		**Power Supply**																
2		**Production**																
3	500-557	Fuel	FUEL															
4	500-557	Non-Fuel O&M - Demand	PROD1															
5	500-557	Non-Fuel O&M - Energy	PROD1															
6		Subtotal - Production																
7		**Purchases**																
8	555	Direct Assign. Chgs (Cr.)																
9	555	Fixed Charges	SUB	1,396,716					1,396,716									
10	555	Demand Charges	PURKW-1	17,977,029		16,203,287												
11	555	Summer	PURKW-2															
12	555	Winter	PURKW-3															
13	555	Other	PURKW-4															
14	555	Energy Charges	PURKWH-1	8,075,688														
15	555	On-Peak	PURKWH-2	25,091,122	25,091,122													
16	555	Off-Peak	PURKWH-3	20,684,954	20,684,954													
17	555	Revenue Related Charges	REV															
18		Subtotal - Purchases		73,225,508	45,776,075	16,203,287			1,396,716									
19	500-557	Total Power Supply		73,225,508	45,776,075	16,203,287			1,396,716									
20																		
21		**Transmission**																
22	560-573	Operation & Maintenance	TRAN2															
23	555	Transmission - G&T Charges	TRAN2															
24		Total Transmission																
25																		
26		**Distribution**																
27	580	Oper. Super & Eng.	EX1	463,993					1,129		160,235	155,501				147,128		
28	581	Load Dispatch	EX1	1,419					3		490	475				450		
29	582	Oper. Station	SUB	9,334					9,334									
30	583	Oper. OH Line	PRI-OH	1,627,322							825,861	801,460						
31	584	Oper. UG Line	PRI-OH	524,403							266,133	258,270						
32	585	Oper. St. Lighting	STL															
33	586	Oper. Meters	MTR	1,216,075												1,216,075		
34	587	Oper. Cons. Install	ICON	457,968							232,417	225,550						
35	588	Oper. Misc. Oper.	EX1	1,039,115					2,529		358,847	348,245				329,494		
36	589	Rents	EX1	449					1		155	150				142		
37	590	Main. Super. & Eng.	EX2	45,285							22,679	22,009	204	298		95		
38	591	Main. Structure	SUB															
39	592	Main. Station	SUB															
40	593	Main. OH Line	PRI-OH	3,436,824							1,744,179	1,692,646						
41	594	Main. UG Line	PRI-OH	292,046							148,212	143,833						
42	595	Main. Line Transf.	TRF	41,904									17,051	24,853				
43	596	Main. St. Lighting	STL															
44	597	Main. Meters	MTR	7,957												7,957		
45	598	Main. Misc. Dist.	EX2															
46	580-598	Subtotal		9,164,094					12,997		3,759,209	3,648,140	17,255	25,151		1,701,341		

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Classification of Revenue Requirements – BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Schedule I Farm And Home Direct	Schedule I-A Residential Marketing Direct	Schedule I(2) Small Commercial Direct	Schedule II Large Power Direct	Schedule XI Large Industrial LPB1 Direct	Schedule XIII Large Industrial LPB2 Direct	Schedule XIV Large Industrial LPB Direct	Schedule 2-A Large Power Time of Day Direct	Outdoor Lighting Service Direct
1		**Power Supply**											
2		**Production**											
3	500-557	Fuel	FUEL										
4	500-557	Non-Fuel O&M - Demand	PROD1										
5	500-557	Non-Fuel O&M - Energy	PROD1										
6		Subtotal - Production											
7		**Purchases**											
8	555	Direct Assign. Chgs (Cr.)											
9	555	Fixed Charges	SUB	1,396,716									
10	555	Demand Charges	PURKW-1	17,977,029					712,620	921,890	139,232		
11	555	Summer	PURKW-2										
12	555	Winter	PURKW-3										
13	555	Other	PURKW-4										
14	555	Energy Charges	PURKWH-1	8,075,688					2,856,307	4,804,171	415,210		
15	555	On-Peak	PURKWH-2	25,091,122									
16	555	Off-Peak	PURKWH-3	20,684,954									
17	555	Revenue Related Charges	REV										
18		Subtotal - Purchases		73,225,508					3,568,927	5,726,061	554,442		
19	500-557	Total Power Supply		73,225,508					3,568,927	5,726,061	554,442		
20													
21		**Transmission**											
22	560-573	Operation & Maintenance	TRAN2										
23	555	Transmission - G&T Charges	TRAN2										
24		Total Transmission											
25													
26		**Distribution**											
27	580	Oper. Super & Eng.	EX1	463,993									
28	581	Load Dispatch	EX1	1,419									
29	582	Oper. Station	SUB	9,334									
30	583	Oper. OH Line	PRI-OH	1,627,322									
31	584	Oper. UG Line	PRI-OH	524,403									
32	585	Oper. St. Lighting	STL										
33	586	Oper. Meters	MTR	1,216,075									
34	587	Oper. Cons. Install	ICON	457,968									
35	588	Oper. Misc. Oper.	EX1	1,039,115									
36	589	Rents	EX1	449									
37	590	Main. Super. & Eng.	EX2	45,285									
38	591	Main. Structure	SUB										
39	592	Main. Station	SUB										
40	593	Main. OH Line	PRI-OH	3,436,824									
41	594	Main. UG Line	PRI-OH	292,046									
42	595	Main. Line Transf.	TRF	41,904									
43	596	Main. St. Lighting	STL										
44	597	Main. Meters	MTR	7,957									
45	598	Main. Misc. Dist.	EX2										
46	580-598	Subtotal		9,164,094									

Classification of Revenue Requirements – BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
47		Consumer Acct., Service & Sales																
48		Consumer Accounting																
49	901	Supervision	CACC	169,929													169,929	
50	902	Meter Reading Expense	CACC	226,481													226,481	
51	903	Records & Collections	CACC	2,836,622													2,836,622	
52	904	Uncollectible Accounts	CACC	194,296													194,296	
53	905	Misc. Customer Account	CACC															
54		Subtotal		3,427,328													3,427,328	
55																		
56		Consumer Service & Info.																
57	907	Supervision	CS	46,258													46,258	
58	908	Customer Assistance	CS	198,107													198,107	
59	909	Info. & Instruction	CS	20,306													20,306	
60	910	Misc. Cust Serv. & Info	CS	294,682													294,682	
61		Subtotal		559,353													559,353	
62																		
63		Sales																
64	911	Supervision	SALES															
65	912	Demonstrating & Selling	SALES															
66	913	Advertising	SALES															
67	916	Misc. Sales	SALES															
68		Subtotal																
69																		
70		Prorated Operating Expenses																
71	920-	Administrative & General																
72	932	Power Supply	EX6-PS															
73		Transmission	EX6-TR															
74		Distribution	EX6-D	2,738,691					265,391		707,704	686,794	3,248	4,735		320,292	750,527	
75		Subtotal - A&G		2,738,691					265,391		707,704	686,794	3,248	4,735		320,292	750,527	
76																		
77	408	Other Taxes																
78		Power Supply	EX6-PS															
79		Transmission	EX6-TR															
80		Distribution	EX6-D	138,361					13,408		35,754	34,697	164	239		16,181	37,917	
81		Subtotal - Other Taxes		138,361					13,408		35,754	34,697	164	239		16,181	37,917	
82																		
83	421-	Miscellaneous Expense																
84	426,431	Power Supply	EX6-PS															
85		Transmission	EX6-TR															
86		Distribution	EX6-D	352,722					34,180		91,147	88,454	418	610		41,251	96,662	
87		Subtotal - Misc. Expense		352,722					34,180		91,147	88,454	418	610		41,251	96,662	

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Classification of Revenue Requirements – BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Schedule I Farm And Home Direct	Schedule I-A Residential Marketing Direct	Schedule I(2) Small Commercial Direct	Schedule II Large Power Direct	Schedule XI Large Industrial LPB1 Direct	Schedule XIII Large Industrial LPB2 Direct	Schedule XIV Large Industrial LPB Direct	Schedule 2-A Large Power Time of Day Direct	Outdoor Lighting Service Direct
47		Consumer Acct., Service & Sales											
48		Consumer Accounting											
49	901	Supervision	CACC	169,929									
50	902	Meter Reading Expense	CACC	226,481									
51	903	Records & Collections	CACC	2,836,622									
52	904	Uncollectible Accounts	CACC	194,296									
53	905	Misc. Customer Account	CACC										
54		Subtotal		3,427,328									
55													
56		Consumer Service & Info.											
57	907	Supervision	CS	46,258									
58	908	Customer Assistance	CS	198,107									
59	909	Info. & Instruction	CS	20,306									
60	910	Misc. Cust Serv. & Info	CS	294,682									
61		Subtotal		559,353									
62													
63		Sales											
64	911	Supervision	SALES										
65	912	Demonstrating & Selling	SALES										
66	913	Advertising	SALES										
67	916	Misc. Sales	SALES										
68		Subtotal											
69													
70		Prorated Operating Expenses											
71	920-	Administrative & General											
72	932	Power Supply	EX6-PS										
73		Transmission	EX6-TR										
74		Distribution	EX6-D	2,738,691									
75		Subtotal - A&G		2,738,691									
76													
77	408	Other Taxes											
78		Power Supply	EX6-PS										
79		Transmission	EX6-TR										
80		Distribution	EX6-D	138,361									
81		Subtotal - Other Taxes		138,361									
82													
83	421-	Miscellaneous Expense											
84	426,431	Power Supply	EX6-PS										
85		Transmission	EX6-TR										
86		Distribution	EX6-D	352,722									
87		Subtotal - Misc. Expense		352,722									

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Classification of Revenue Requirements – BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
88		Fixed Charges																
89	403-	**Depreciation**																
90	407	Power Supply	PROPLNT															
91		Transmission	TRNPLNT															
92		Distribution	DSTPLNT	9,214,432					14,367		3,386,593	2,789,478	520,075	758,062	922,632	816,907		
93		Subtotal - Depreciation		9,214,432					14,367		3,386,593	2,789,478	520,075	758,062	922,632	816,907		
94																		
95	408	**Property Taxes**																
96		Power Supply	PROPLNT															
97		Transmission	TRNPLNT															
98		Distribution	DSTPLNT															
99		Subtotal - Property Taxes																
100																		
101	427	**Interest-LT**																
102		Power Supply	PROPLNT															
103		Transmission	TRNPLNT															
104		Distribution	DSTPLNT	4,525,476					7,056		1,663,255	1,369,994	255,424	372,307	453,132	401,207		
105		Subtotal - Interest-LT		4,525,476					7,056		1,663,255	1,369,994	255,424	372,307	453,132	401,207		
106																		
107		**Required Margin**																
108		Power Supply	PROPLNT															
109		Transmission	TRNPLNT															
110		Distribution	DSTPLNT	4,175,536					6,510		1,534,641	1,264,057	235,673	343,517	418,092	370,183		
111		Subtotal - Required Margin		4,175,536					6,510		1,534,641	1,264,057	235,673	343,517	418,092	370,183		
112																		
113		Summary of Revenue Requirements																
114		Power Supply		71,828,792	45,776,075	16,203,287												
115		Transmission																
116		Distribution		35,692,710					1,750,624		11,178,302	9,881,613	1,032,257	1,504,621	1,793,856	3,667,363	4,871,788	
117		**Total Revenue Required**		107,521,502	45,776,075	16,203,287			1,750,624		11,178,302	9,881,613	1,032,257	1,504,621	1,793,856	3,667,363	4,871,788	

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Classification of Revenue Requirements – BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Schedule I Farm And Home Direct	Schedule I-A Residential Marketing Direct	Schedule I(2) Small Commercial Direct	Schedule II Large Power Direct	Schedule XI Large Industrial LPB1 Direct	Schedule XIII Large Industrial LPB2 Direct	Schedule XIV Large Industrial LPB Direct	Schedule 2-A Large Power Time of Day Direct	Outdoor Lighting Service Direct
88		Fixed Charges											
89	403-	**Depreciation**											
90	407	Power Supply	PROPLNT										
91		Transmission	TRNPLNT										
92		Distribution	DSTPLNT	9,214,432									6,319
93		Subtotal - Depreciation		9,214,432									6,319
94													
95	408	**Property Taxes**											
96		Power Supply	PROPLNT										
97		Transmission	TRNPLNT										
98		Distribution	DSTPLNT										
99		Subtotal - Property Taxes											
100													
101	427	**Interest-LT**											
102		Power Supply	PROPLNT										
103		Transmission	TRNPLNT										
104		Distribution	DSTPLNT	4,525,476									3,103
105		Subtotal - Interest-LT		4,525,476									3,103
106													
107		**Required Margin**											
108		Power Supply	PROPLNT										
109		Transmission	TRNPLNT										
110		Distribution	DSTPLNT	4,175,536									2,863
111		Subtotal - Required Margin		4,175,536									2,863
112													
113		Summary of Revenue Requirements											
114		Power Supply		71,828,792					3,568,927	5,726,061	554,442		
115		Transmission											
116		Distribution		35,692,710									12,285
117		**Total Revenue Required**		107,521,502					3,568,927	5,726,061	554,442		12,285

Determination of Classification Factors
Used to Functionalize the
Primary Line (O.H.) Accounts 364-365

Conductor Description		Miles	Unit Cost	Replacement Cost
		(mi.)	($/mi.)	($)
All OH	1PH	2,191.8	24,274	53,203,535
4 ACSR or 6 CU	VPH	12.1	31,163	377,130
2 ACSR or 4 CU	VPH	19.4	31,638	613,235
1/0 ACSR or 2 CU	VPH	9.4	32,905	309,340
2/0 ACSR or 1/0 CU	VPH	-	34,218	-
3/0 ACSR or 1/0 CU	VPH	-	35,486	-
4/0 ACSR or 2/0 CU	VPH	-	36,769	-
4 ACSR or 6 CU	3PH	11.5	41,754	480,464
2 ACSR or 4 CU	3PH	35.6	42,388	1,510,866
1/0 ACSR or 2 CU	3PH	219.4	44,077	9,672,446
2/0 ACSR or 1/0 CU	3PH	20.9	45,133	943,466
3/0 ACSR or 1/0 CU	3PH	157.6	46,823	7,380,640
4/0 ACSR or 2/0 CU	3PH	-	48,534	-
267 ACSR	3PH	-	53,441	-
336 ACSR	3PH	332.4	55,131	18,325,993
397 ACSR	3PH	-	57,665	-
477 ACSR	3PH	15.4	58,650	906,026
Total		3,025.7		93,723,141

1. The zero capacity cost is estimated from the zero intercept graph to be: $15,256

2. The consumer component of the total replacement cost is taken to be the cost if all lines were constructed with zero capacity:

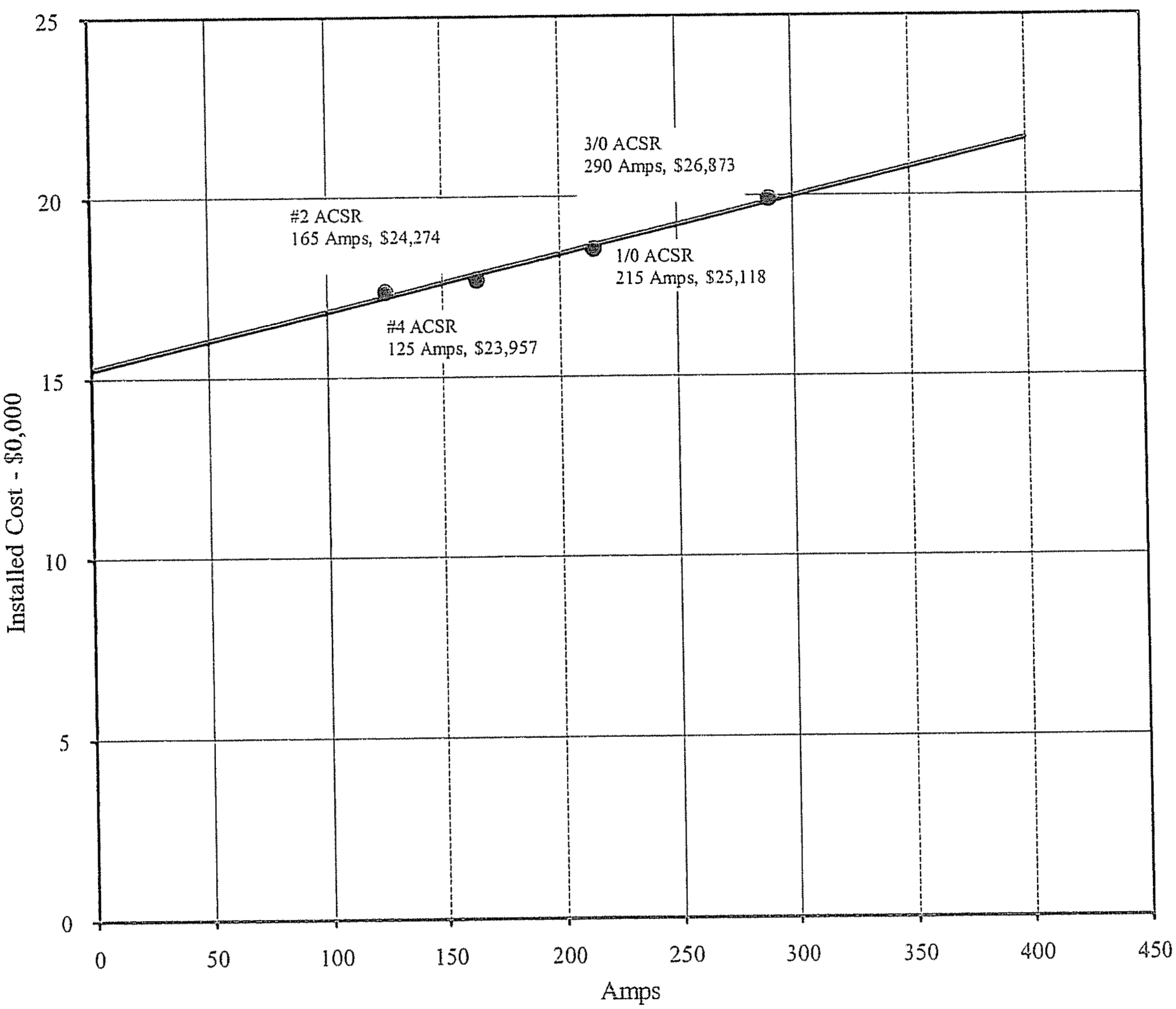
   3,026 x $15,256 = $46,158,908
   or 49.25% of total replacement cost.

3. The capacity component of the total replacement cost is then equal to the difference between the total cost and the consumer component:

   $93,723,141 - $46,158,908 = $47,564,232
   or 50.75% of total replacement cost.

Electric Plant Functionalization

Primary Line (O.H.) Construction Costs
Versus
Thermal Capacity



Determination of Classification Factors
Used to Functionalize the
Primary Line (U.G.) Accounts 366-367

Conductor Description		Miles	Unit Cost	Replacement Cost
		(mi.)	($/mi.)	($)
All UG	1PH	200.4	26,566	5,323,295
1/0 URD	VPH	23.5	56,971	1,341,159
4/0 URD	VPH	0.8	60,456	49,876
500 MCM URD	VPH	-	149,988	-
750 MCM URD	VPH	-	160,020	-
1/0 URD	VPH	83.1	81,557	6,778,593
4/0 URD	VPH	9.9	86,784	858,033
500 MCM URD	3PH	11.5	190,392	2,188,746
750 MCM URD	3PH		205,440	-
Total		329.2		16,539,703

1. The zero capacity cost is estimated from the zero intercept graph to be: $15,464

2. The consumer component of the total replacement cost is taken to be the cost if all lines were constructed with zero capacity:

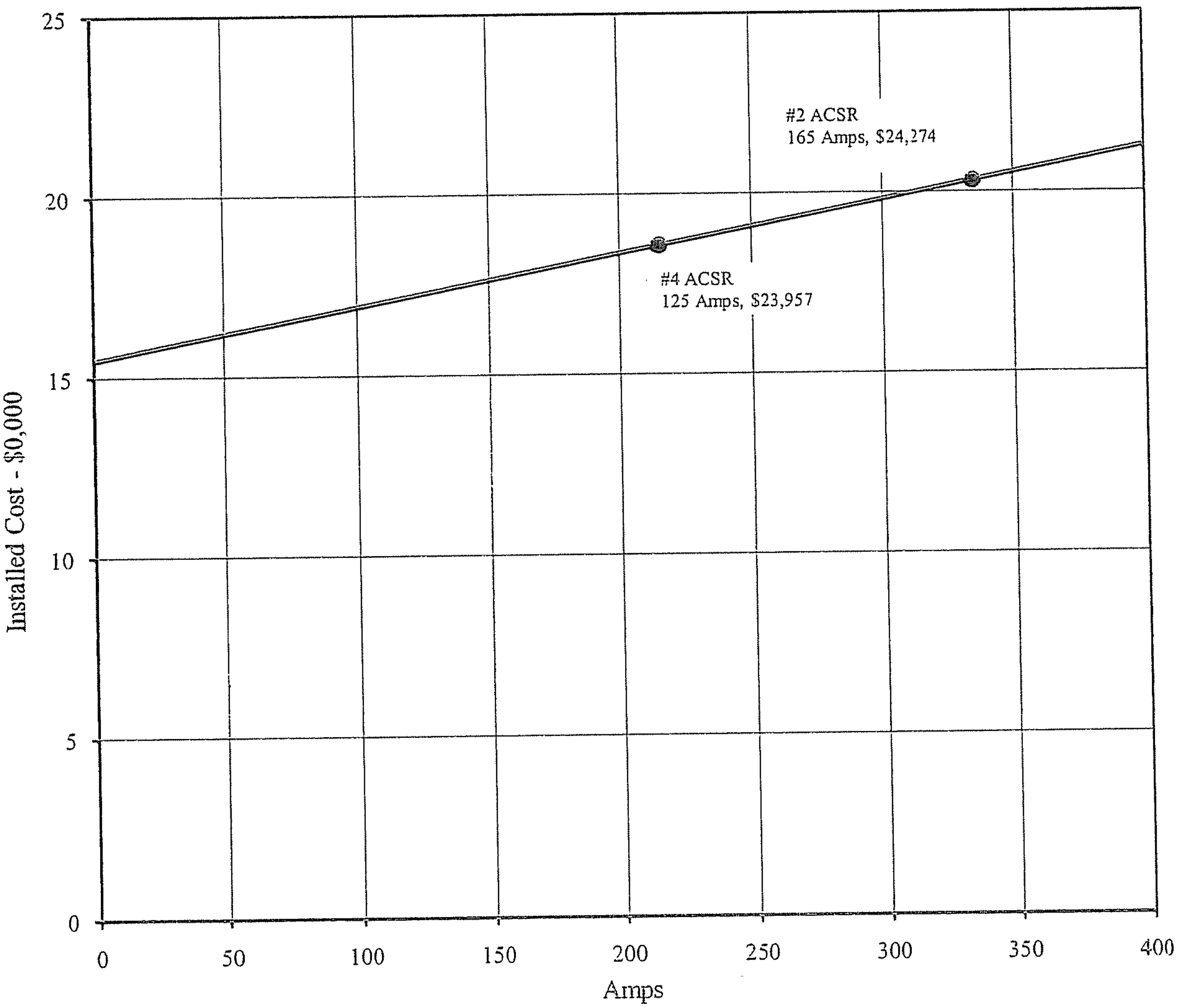
   329 x $15,464 = $5,091,410
   or 30.78% of total replacement cost.

3. The capacity component of the total replacement cost is then equal to the difference between the total cost and the consumer component:

   $16,539,703 - $5,091,410 = $11,448,293
   or 69.22% of total replacement cost.

Electric Plant Functionalization

Primary Line (U.G.) Construction Costs
Versus
Thermal Capacity



Determination of Classification Factors
Used to Functionalize the
Service Transformer Account 368

kVA Size	Quantity	Total kVA	Unit Cost	Replacement Cost
		(kVA)	($/unit)	($)
1.5	224	336.0	756	169,344
3.0	8	24.0	756	6,048
5.0	363	1,815.0	756	274,428
10.0	4,635	46,350.0	757	3,508,695
15.0	12,700	190,500.0	810	10,287,000
25.0	4,709	117,725.0	917	4,318,153
37.5	107	4,012.5	1,060	113,420
50.0	4,564	228,200.0	1,223	5,581,772
75.0	366	27,450.0	1,718	628,788
100.0	195	19,500.0	2,291	446,745
150.0	25	3,750.0	3,192	79,800
167.0	5	835.0	3,641	18,205
225.0	6	1,350.0	4,838	29,028
250.0	1	250.0	5,429	5,429
300.0	66	19,800.0	6,484	427,944
333.0		-	7,215	-
500.0	50	25,000.0	10,307	515,350
667.0	-	-	13,423	-
750.0	35	26,250.0	15,059	527,065
1,000.0	29	29,000.0	19,613	568,777
1,500.0	26	39,000.0	28,920	751,920
2,000.0	9	18,000.0	37,726	339,534
Totals	28,123	799,147.5		28,597,445

1. The cost of a transformer with zero capacity is estimated from the zero intercept graph to be $603.

2. The consumer component of the total replacement cost is taken to be the cost if all transformers had zero capacity.

   28,123 x $603 = $16,961,130

   or 59.31% of the total replacement cost.

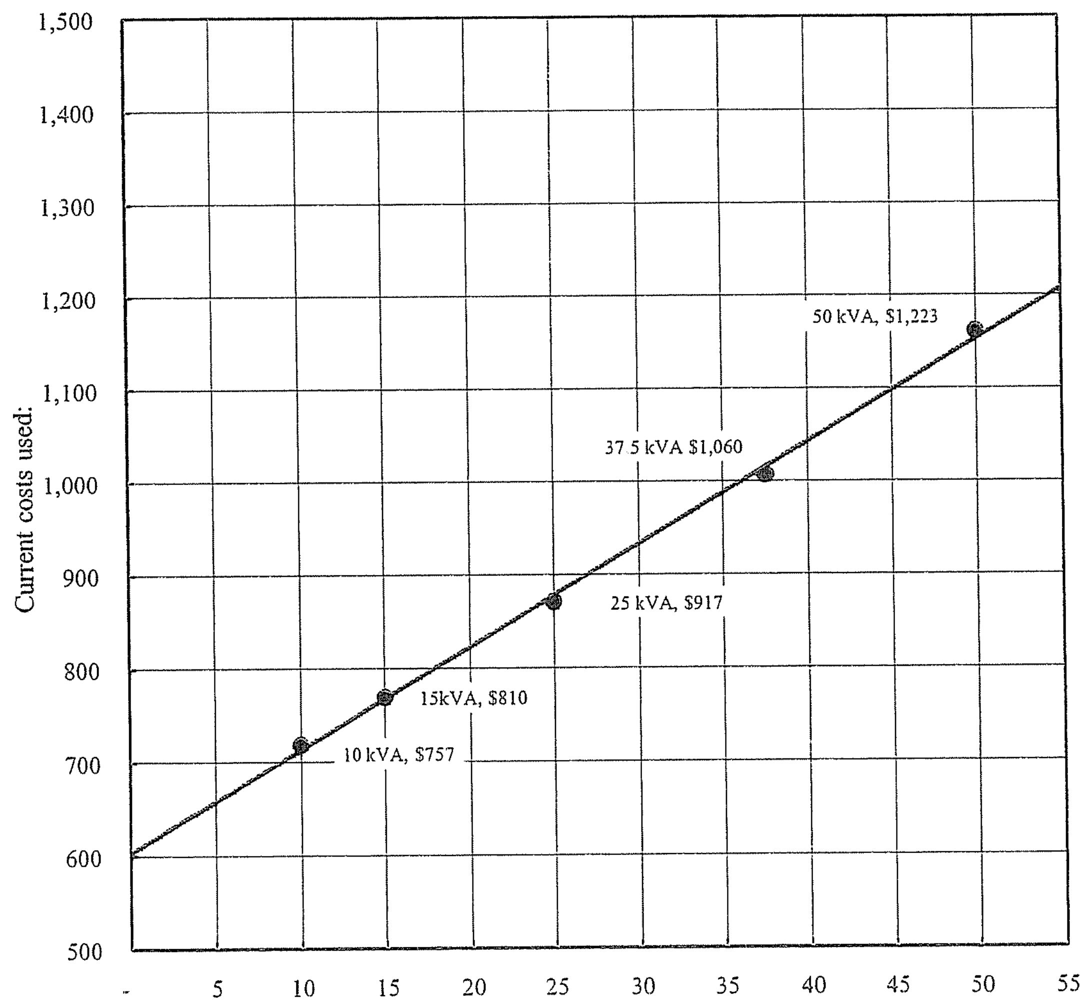
3. The capacity component of the total replacement cost is then equal to the difference between the total cost and the consumer component:

   $28,597,445 - $16,961,130 = $11,636,315

   or 40.69% of the total replacement cost.

Electric Plant Functionalization

Line Transformer (O.H.) Installed Cost
Versus
Thermal Capacity



Summary of Classification Factors – BUNDLED

Line No.	Name	Description	Source	Total	Power Supply Energy	Power Supply Cap.	Transmission Energy	Transmission Capacity	Dist. Substation Cap.	Dist. Substation Cons.	Primary Line Cap.	Primary Line Cons.	Line Transf. Cap.	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
		Classification Factor Data																
1	PROPLNT	Production Plant	Plant															
2	TRNPLNT	Transmission Plant	Plant															
3	DSTPLNT	Distribution Plant	Plant	180,493,852					281,416		66,337,157	54,640,758	10,187,308	##########	18,072,677	16,001,709		
4	PLNT	Prod, Trans, Dist. Subtotal	Plant	180,493,852					281,416		66,337,157	54,640,758	10,187,308	##########	18,072,677	16,001,709		
5	EX1	Assigned Dist. Oper. Exp.	Rev Req	3,835,102					9,334		1,324,412	1,285,281				1,216,075		
6	EX2	Assigned Dist. Main. Exp.	Rev Req	3,778,731							1,892,391	1,836,479	17,051	24,853		7,957		
7	EX3	Dist. Oper. & Main.	Rev Req	9,164,094					12,997		3,759,209	3,648,140	17,255	25,151		1,701,341		
8	EX4	Assigned O & M Exp.	Rev Req	86,376,283	45,776,075	16,203,287			1,409,713		3,759,209	3,648,140	17,255	25,151		1,701,341	3,986,681	
9	EX4-PS	Power Supply	Rev Req	71,828,792	45,776,075	16,203,287												
10	EX4-TR	Transmission	Rev Req															
11	EX4-D	Distribution	Rev Req	14,547,491					1,409,713		3,759,209	3,648,140	17,255	25,151		1,701,341	3,986,681	
12	EX5	Rev. Req. Less Margin	Rev Req	100,116,192	45,776,075	16,203,287			1,431,135		8,809,057	7,807,612	792,754	1,155,520	1,375,764	2,919,455	3,986,681	
13	EX5-PS	Power Supply	Rev Req	71,828,792	45,776,075	16,203,287												
14	EX5-TR	Transmission	Rev Req															
15	EX5-D	Distribution	Rev Req	28,287,399					1,431,135		8,809,057	7,807,612	792,754	1,155,520	1,375,764	2,919,455	3,986,681	

Summary of Classification Factors -- BUNDLED

Line No.	Name	Description	Source	Total	Schedule I Farm And Home Direct	Schedule I-A Residential Marketing Direct	Schedule I(2) Small Commercial Direct	Schedule II Large Power Direct	Schedule XI Large Industrial LPB1 Direct	Schedule XIII Large Industrial LPB2 Direct	Schedule XIV Large Industrial LPB Direct	Schedule 2-A Large Power Time of Day Direct	Outdoor Lighting Service Direct
		Classification Factor Data											
1	PROPLNT	Production Plant	Plant										
2	TRNPLNT	Transmission Plant	Plant										
3	DSTPLNT	Distribution Plant	Plant	180,493,852									123,773
4	PLNT	Prod, Trans, Dist. Subtotal	Plant	180,493,852									123,773
5	EX1	Assigned Dist. Oper. Exp.	Rev Req	3,835,102									
6	EX2	Assigned Dist. Main. Exp.	Rev Req	3,778,731									
7	EX3	Dist. Oper. & Main.	Rev Req	9,164,094									
8	EX4	Assigned O & M Exp.	Rev Req	86,376,283					3,568,927	5,726,061	554,442		
9	EX4-PS	Power Supply	Rev Req	71,828,792					3,568,927	5,726,061	554,442		
10	EX4-TR	Transmission	Rev Req										
11	EX4-D	Distribution	Rev Req	14,547,491									9,422
12	EX5	Rev. Req. Less Margin	Rev Req	100,116,192					3,568,927	5,726,061	554,442		
13	EX5-PS	Power Supply	Rev Req	71,828,792					3,568,927	5,726,061	554,442		
14	EX5-TR	Transmission	Rev Req										
15	EX5-D	Distribution	Rev Req	28,287,399									9,422

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Summary of Classification Factors -- BUNDLED

Line No.	Name	Description	Source	Total	Power Supply Energy	Power Supply Cap.	Transmission Energy	Transmission Capacity	Dist. Substation Cap.	Dist. Substation Cons.	Primary Line Cap.	Primary Line Cons.	Line Transf. Cap.	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
16	Classification Factors																	
17	CACC	Consumer Accounting	Input	1.000000													1.000000	
18	CS	Customer Service	Input	1.000000													1.000000	
19	CS-PS	Cust. Service - Pwr. Supply	Input															
20	CS-TR	Cust. Service - Transmission	Input															
21	CS-D	Cust. Service - Distribution	Input	1.000000													1.000000	
22	SALES	Sales	Input	1.000000													1.000000	
23	SALES-PS	Sales - Power Supply	Input															
24	SALES-TR	Sales - Transmission	Input															
25	SALES-D	Sales - Distribution	Input	1.000000													1.000000	
26	PROPLNT	Production Plant	Plant															
27	TRNPLNT	Transmission Plant	Plant															
28	DSTPLNT	Distribution Plant	Plant	1.000000					0.001559		0.367531	0.302729	0.056441	0.082269	0.100129	0.088655		
29	PLNT	Prod, Trans, Dist. Subtotal	Plant	1.000000					0.001559		0.367531	0.302729	0.056441	0.082269	0.100129	0.088655		
30	EX1	Assigned Dist. Oper. Exp.	Rev Req	1.000000					0.002434		0.345339	0.335136				0.317091		
31	EX2	Assigned Dist. Main. Exp.	Rev Req	1.000000							0.500801	0.486004	0.004512	0.006577		0.002106		
32	EX3	Dist. Oper. & Main.	Rev Req	1.000000					0.001418		0.410211	0.398091	0.001883	0.002745		0.185653		
33	EX4	Assigned O & M Exp.	Rev Req	1.000000	0.529961	0.187590			0.016321		0.043521	0.042235	0.000200	0.000291		0.019697	0.046155	
34	EX4-PS	Power Supply	Rev Req	0.831580	0.529961	0.187590												
35	EX4-TR	Transmission	Rev Req															
36	EX4-D	Distribution	Rev Req	0.168420					0.016321		0.043521	0.042235	0.000200	0.000291		0.019697	0.046155	
37	EX5	Rev. Req. Less Margin	Rev Req	1.000000	0.457229	0.161845			0.014295		0.087988	0.077986	0.007918	0.011542	0.013742	0.029161	0.039821	
38	EX5-PS	Power Supply	Rev Req	0.717454	0.457229	0.161845												
39	EX5-TR	Transmission	Rev Req															
40	EX5-D	Distribution	Rev Req	0.282546					0.014295		0.087988	0.077986	0.007918	0.011542	0.013742	0.029161	0.039821	
41	EX6	A&G Classification	Input	1.000000					0.096904		0.258409	0.250775	0.001186	0.001729		0.116951	0.274046	
42	EX6-PS	Power Supply	Input															
43	EX6-TR	Transmission	Input															
44	EX6-D	Distribution	Input	1.000000					0.096904		0.258409	0.250775	0.001186	0.001729		0.116951	0.274046	
45	FUEL	Fuel	Input															
46	ICON	Install Cons. Prem.	Input	1.000000							0.507497	0.492503						
47	LAND	Land & Land Rights	Input	1.000000					1.00000									
48	LICON	Leased Property	Input	1.000000							0.507497	0.492503						
49	MTR	Meters	Input	1.000000												1.000000		
50	PRI-OH	Primary Line	Input	1.000000							0.507497	0.492503						
51	PRI-UG	Primary Line	Input	1.000000							0.692170	0.307830						
52	PROD1	Production Plant	Input															
53	PROD2	Production O & M	Input															
54	PURTR-1	Trans. Capacity	Input	1.000000				1.000000										
55	PURTR-2	Trans. Energy	Input	1.000000	1.000000													
56	PURKW-1	Purchased Power Capacity	Input	1.000000		1.000000												
57	PURKW-2	Summer	Input	1.000000		1.000000												
58	PURKW-3	Winter	Input	1.000000		1.000000												
59	PURKW-4	Other	Input	1.000000		1.000000												
60	PURKWH-1	Purchased Power Energy	Input	1.000000	1.000000													
61	PURKWH-2	On-Peak	Input	1.000000	1.000000													
62	PURKWH-3	Off-Peak	Input	1.000000	1.000000													
61	SERV	Services	Input	1.000000											1.000000			
62	STL	Street Lighting	Input															
63	SUB	Substation	Input	1.000000					1.000000									
52	TRAN2	Transmission Purchases	Input															
53	TRF	Line Transf.	Input	1.000000									0.406901	0.593099				
54	REV	Revenue Related	Input	1.000000														1.000000
55	PP	Purchased Power	Input	1.000000	0.738570	0.261430												
56	USER02	User Defined 02	Input															
57	USER03	User Defined 03	Input															

Summary of Classification Factors -- BUNDLED

Line No.	Name	Description	Source	Total	Schedule I Farm And Home Direct	Schedule I-A Residential Marketing Direct	Schedule I(2) Small Commercial Direct	Schedule II Large Power Direct	Schedule XI Large Industrial LPB1 Direct	Schedule XIII Large Industrial LPB2 Direct	Schedule XIV Large Industrial LPB Direct	Schedule 2-A Large Power Time of Day Direct	Outdoor Lighting Service Direct
16	**Classification Factors**												
17	CACC	Consumer Accounting	Input	1.000000									
18	CS	Customer Service	Input	1.000000									
19	CS-PS	Cust. Service - Pwr. Supply	Input										
20	CS-TR	Cust. Service - Transmission	Input										
21	CS-D	Cust. Service - Distribution	Input	1.000000									
22	SALES	Sales	Input	1.000000									
23	SALES-PS	Sales - Power Supply	Input										
24	SALES-TR	Sales - Transmission	Input										
25	SALES-D	Sales - Distribution	Input	1.000000									
26	PROPLNT	Production Plant	Plant										
27	TRNPLNT	Transmission Plant	Plant										
28	DSTPLNT	Distribution Plant	Plant	1.000000									0.000686
29	PLNT	Prod. Trans. Dist. Subtotal	Plant	1.000000									0.000686
30	EX1	Assigned Dist. Oper. Exp.	Rev Req	1.000000									
31	EX2	Assigned Dist. Main. Exp.	Rev Req	1.000000									
32	EX3	Dist. Oper. & Main.	Rev Req	1.000000									
33	EX4	Assigned O & M Exp.	Rev Req	1.000000					0.041318	0.066292	0.006419		
34	EX4-PS	Power Supply	Rev Req	0.831580					0.041318	0.066292	0.006419		
35	EX4-TR	Transmission	Rev Req										
36	EX4-D	Distribution	Rev Req	0.168420									
37	EX5	Rev. Req. Less Margin	Rev Req	1.000000					0.035648	0.057194	0.005538		0.000094
38	EX5-PS	Power Supply	Rev Req	0.717454					0.035648	0.057194	0.005538		
39	EX5-TR	Transmission	Rev Req										
40	EX5-D	Distribution	Rev Req	0.282546									0.000094
41	EX6	A&G Classification	Input	1.000000									
42	EX6-PS	Power Supply	Input										
43	EX6-TR	Transmission	Input										
44	EX6-D	Distribution	Input	1.000000									
45	FUEL	Fuel	Input										
46	ICON	Install Cons. Prem.	Input	1.000000									
47	LAND	Land & Land Rights	Input	1.000000									
48	LICON	Leased Property	Input	1.000000									
49	MTR	Meters	Input	1.000000									
50	PRI-OH	Primary Line	Input	1.000000									
51	PRI-UG	Primary Line	Input	1.000000									
52	PROD1	Production Plant	Input										
53	PROD2	Production O & M	Input										
54	PURTR-1	Trans. Capacity	Input	1.000000									
55	PURTR-2	Trans. Energy	Input	1.000000									
56	PURKW-1	Purchased Power Capacity	Input	1.000000									
57	PURKW-2	Summer	Input	1.000000									
58	PURKW-3	Winter	Input	1.000000									
59	PURKW-4	Other	Input	1.000000									
60	PURKWH-1	Purchased Power Energy	Input	1.000000									
61	PURKWH-2	On-Peak	Input	1.000000									
62	PURKWH-3	Off-Peak	Input	1.000000									
61	SERV	Services	Input	1.000000									
62	STL	Street Lighting	Input										
63	SUB	Substation	Input	1.000000									
52	TRAN2	Transmission Purchases	Input										
53	TRF	Line Transf.	Input	1.000000									
54	REV	Revenue Related	Input	1.000000									
55	PP	Purchased Power	Input	1.000000									
56	USER02	User Defined 02	Input										
57	USER03	User Defined 03	Input										

Summary of Allocation of Revenue Requirements to Rate Classes -- BUNDLED

Line No.	Cost Classification		Alloc. Factor	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
1	**Power Supply**												
2	**Wholesale Power**												
3	Direct Assigned Charges (Credits)		Direct										
4	Demand Related		D7	17,977,029	13,830,293		775,401	1,356,233	712,620	921,890	139,232	49,184	192,176
5	Demand Related - Summer		D4										
6	Demand Related - Winter		D5										
7	Demand Related - Other		D6										
8	Subtotal - Demand			17,977,029	13,830,293		775,401	1,356,233	712,620	921,890	139,232	49,184	192,176
9	Energy Related		E1	8,075,688					2,856,307	4,804,171	415,210		
10	Energy Related - On-Peak		E2	25,091,122	18,777,042	226	1,269,329	4,899,348				100,062	45,115
11	Energy Related - Off-Peak		E3	20,684,954	15,555,356	1,001	993,011	3,741,263				76,410	317,913
12	Subtotal - Energy			53,851,763	34,332,398	1,226	2,262,340	8,640,611	2,856,307	4,804,171	415,210	176,472	363,028
13	Revenue Related		R1										
14	Subtotal - Wholesale			71,828,792	48,162,691	1,226	3,037,740	9,996,844	3,568,927	5,726,061	554,442	225,656	555,204
15	**Allocated Overhead & Margin**												
16	Direct Related		Direct										
17	Revenue Related		R1										
18	Demand Related		D7										
19	Energy Related		E1										
20	Subtotal - Allocated												
21	Subtotal - Power Supply			71,828,792	48,162,691	1,226	3,037,740	9,996,844	3,568,927	5,726,061	554,442	225,656	555,204
22			ERROR										
23	**Transmission**												
24	Direct Assigned		Direct										
25	Demand Related		D7										
26	Energy Related		E1										
27	Subtotal--Transmission												
28	**Allocated Overhead & Margin**												
29	Direct Related		Direct										
30	Revenue Related		R1										
31	Demand Related		D7										
32	Energy Related		E1										
33	Subtotal - Allocated												
34	Subtotal - Transmission												
35													
36	**Distribution**												
37	Power Supply	-Energy	E1										
38	Dist. Sub.	-Capacity	D9	1,750,624	1,188,495	43	83,354	171,313	102,020	165,922	16,426	5,458	17,592
39	Dist. Sub.	-Consumer	C2										
40	Primary Line	-Capacity	D9	11,178,302	7,588,923	275	532,243	1,093,889	651,433	1,059,466	104,886	34,851	112,334
41	Primary Line	-Consumer	C2	9,881,613	9,186,920	68	389,725	74,326	2,676	595	1,189	2,676	223,438
42	Line Transf.	-Capacity	D1	1,032,257	918,910	67	26,494	51,068	12,157	13,816	2,281	984	6,480
43	Line Transf.	-Consumer	C3	1,504,621	1,399,833	10	59,383	10,355	373	83	166	373	34,046
44	Sec. & Serv.	-Consumer	C4	1,793,856	1,668,912	12	70,798	12,345	444	99	198	458	40,590
45	Meter	-Consumer	C5	3,667,363	3,347,666	248	142,014	87,443				8,572	81,420
46	Acct. & Serv.	-Consumer	C6	4,871,788	4,429,841	328	187,922	115,710	11,343	2,521	5,041	11,343	107,740
47	Revenue Related	-Revenue	R1										
48	Direct Assigned		Direct	12,285									12,285
49	Subtotal - Distribution			35,692,710	29,729,500	1,051	1,491,934	1,616,450	780,447	1,242,501	130,187	64,714	635,925
50	**Total**			107,521,502	77,892,192	2,278	4,529,674	11,613,294	4,349,374	6,968,562	684,629	290,370	1,191,129

Allocation of Plant in Service To Rate Classes -- BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
1		**Intangible Plant**											
2	301	Organization	PLNT										
3	302	Franchises and consents	PLNT										
4	303	Miscellaneous intangible plant	PLNT										
5	301-303	Subtotal	PLNT										
6													
7		**Production Plant**											
8	310-346	Production Plant	PROD1										
9													
10		**Transmission Plant**											
11	350-359	Transmission Plant	TRAN1										
12													
13		**Distribution Plant**											
14	360	Land	LAND										
15	361	Structures	SUB										
16	362	Station	SUB	281,416	240,202		13,467	23,555				854	3,338
17	363	Battery	SUB										
18	364	Poles, towers	PRI	51,381,498	41,229,425	816	2,239,617	2,742,090	1,526,471	2,472,972	247,717	88,151	834,240
19	365	OH Cond	PRI	37,592,766	30,165,102	597	1,638,593	2,006,223	1,116,827	1,809,325	181,240	64,495	610,364
20	366	UG Conduit	PRI										
21	367	UG Cond	PRI	26,756,464	20,230,604	513	1,206,653	1,874,290	1,081,515	1,755,802	174,765	59,971	372,351
22	368	Transf	TRF	25,036,362	22,883,593	764	847,518	606,174	123,660	137,169	24,147	13,390	399,950
23	369	Services	SERV	18,072,677	16,813,890	124	713,275	124,372	4,477	995	1,990	4,617	408,936
24	370	Meters	MTR	16,001,709	14,606,787	1,080	619,646	381,539				37,401	355,256
25	371	Cons Premise	ICON	5,247,187	4,210,436	83	228,714	280,028	155,886	252,545	25,297	9,002	85,194
26	372	Leased Prop	LICON										
27	373	St. Light	STL	123,773									123,773
28	360-373	Subtotal		180,493,852	150,380,037	3,978	7,507,483	8,038,270	4,008,837	6,428,808	655,156	277,880	3,193,402
29													
30		**General Plant**											
31	389	Land & Land Rights	PLNT	2,259,072	1,882,166	50	93,964	100,607	50,175	80,463	8,200	3,478	39,969
32	390	Structures and Improve.	PLNT	9,883,594	8,234,603	218	411,099	440,165	219,518	352,033	35,875	15,216	174,866
33	391	Office Furniture & Equip.	PLNT	2,452,348	2,043,195	54	102,003	109,215	54,468	87,347	8,902	3,776	43,388
34	392	Transportation & Equipment	PLNT	5,012,927	4,176,564	110	208,508	223,250	111,339	178,550	18,196	7,718	88,692
35	393	Stores Equipment	PLNT	208,367	173,603	5	8,667	9,280	4,628	7,422	756	321	3,687
36	394	Tool, Shop & Garage Equip.	PLNT	301,014	250,792	7	12,520	13,406	6,686	10,721	1,093	463	5,326
37	395	Laboratory Equipment	PLNT	363,436	302,800	8	15,117	16,186	8,072	12,945	1,319	560	6,430
38	396	Power Operated Equipment	PLNT	199,181	165,949	4	8,285	8,870	4,424	7,094	723	307	3,524
39	397	Communication Equipment	PLNT	2,907,088	2,422,066	64	120,918	129,467	64,568	103,544	10,552	4,476	51,434
40	398	Miscellaneous Equipment	PLNT	125,966	104,950	3	5,239	5,610	2,798	4,487	457	194	2,229
41	399	Other tangible property	PLNT	48,973	40,802	1	2,037	2,181	1,088	1,744	178	75	866
42	389-399	Subtotal		23,761,966	19,797,491	524	988,358	1,058,236	527,762	846,351	86,251	36,583	420,411
43													
44		**Total Plant**		204,255,818	170,177,527	4,502	8,495,841	9,096,506	4,536,599	7,275,159	741,408	314,463	3,613,813

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Allocation of Revenue Requirements to Rate Classes -- BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
1		Power Supply											
2		Production											
3	500-557	Fuel	FUEL										
4	500-557	Non-Fuel O&M - Demand	PROD1										
5	500-557	Non-Fuel O&M - Energy	PROD1										
6		Subtotal - Production											
7		Purchases											
8	555	Direct Assign. Chgs (Cr.)											
9	555	Fixed Charges	PURSUB	1,396,716	948,227	34	66,503	136,680	81,396	132,379	13,105	4,355	14,036
10	555	Demand Charges	PURKW-1	17,977,029	13,830,293		775,401	1,356,233	712,620	921,890	139,232	49,184	192,176
11	555	Summer	PURKW-2										
12	555	Winter	PURKW-3										
13	555	Other	PURKW-4										
14		Total Demand		17,977,029	13,830,293		775,401	1,356,233	712,620	921,890	139,232	49,184	192,176
15	555	Energy Charges	PURKWH-1	8,075,688					2,856,307	4,804,171	415,210		
16	555	On-Peak	PURKWH-2	25,091,122	18,777,042	226	1,269,329	4,899,348				100,062	45,115
17	555	Off-Peak	PURKWH-3	20,684,954	15,555,356	1,001	993,011	3,741,263				76,410	317,913
18		Total Energy		53,851,763	34,332,398	1,226	2,262,340	8,640,611	2,856,307	4,804,171	415,210	176,472	363,028
19	555	Revenue Related Charges	R1										
20		Subtotal - Purchases		73,225,508	49,110,918	1,261	3,104,244	10,133,525	3,650,323	5,858,440	567,547	230,011	569,240
21	500-557	Total Power Supply		73,225,508	49,110,918	1,261	3,104,244	10,133,525	3,650,323	5,858,440	567,547	230,011	569,240
22		Transmission											
23	560-573	Operation & Maintenance	TRAN2										
24	555	Transmission - G&T Charges	TRAN2										
25		Total Transmission											
26		Distribution											
27	580	Oper. Super & Eng.	EX1	463,993	388,421	15	19,513	20,469	9,446	15,303	1,533	889	8,404
28	581	Load Dispatch	EX1	1,419	1,187	0	60	63	29	47	5	3	26
29	582	Oper. Station	SUB	9,334	6,337	0	444	913	544	885	88	29	94
30	583	Oper. OH Line	PRI-OH	1,627,322	1,305,792	26	70,932	86,846	48,345	78,322	7,846	2,792	26,422
31	584	Oper. UG Line	PRI-OH	524,403	420,790	8	22,858	27,986	15,579	25,239	2,528	900	8,514
32	585	Oper. St. Lighting	STL										
33	586	Oper. Meters	MTR	1,216,075	1,110,066	82	47,091	28,996				2,842	26,998
34	587	Oper. Cons. Install	ICON	457,968	367,481	7	19,962	24,440	13,606	22,042	2,208	786	7,436
35	588	Oper. Misc. Oper.	EX1	1,039,115	869,871	34	43,700	45,839	21,154	34,272	3,433	1,991	18,821
36	589	Rents	EX1	449	376	0	19	20	9	15	1	1	8
37	590	Main. Super. & Eng.	EX2	45,285	36,404	1	1,969	2,399	1,330	2,154	216	77	736
38	591	Main. Structure	SUB										
39	592	Main. Station	SUB										
40	593	Main. OH Line	PRI-OH	3,436,824	2,757,769	55	149,804	183,414	102,103	165,413	16,569	5,896	55,801
41	594	Main. UG Line	PRI-OH	292,046	234,343	5	12,730	15,586	8,676	14,056	1,408	501	4,742
42	595	Main. Line Transf.	TRF	41,904	38,301	1	1,419	1,015	207	230	40	22	669
43	596	Main. St. Lighting	STL										
44	597	Main. Meters	MTR	7,957	7,263	1	308	190				19	177
45	598	Main. Misc. Dist.	EX2										
46	580-598	Subtotal		9,164,094	7,544,402	234	390,808	438,175	221,029	357,977	35,875	16,748	158,847

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Allocation of Revenue Requirements to Rate Classes – BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
47		Consumer Acct., Service & Sales											
48		Consumer Accounting											
49	901	Supervision	CACC	169,929	154,514	11	6,555	4,036	396	88	176	396	3,758
50	902	Meter Reading Expense	CACC	226,481	205,936	15	8,736	5,379	527	117	234	527	5,009
51	903	Records & Collections	CACC	2,836,622	2,579,296	191	109,418	67,373	6,604	1,468	2,935	6,604	62,732
52	904	Uncollectible Accounts	CACC	194,296	176,670	13	7,495	4,615	452	101	201	452	4,297
53	905	Misc. Customer Account	CACC										
54		Subtotal		3,427,328	3,116,416	231	132,204	81,403	7,980	1,773	3,546	7,980	75,795
55		Consumer Service & Info.											
56	907	Supervision	CS	46,258	42,062	3	1,784	1,099	108	24	48	108	1,023
57	908	Customer Assistance	CS	198,107	180,135	13	7,642	4,705	461	102	205	461	4,381
58	909	Info. & Instruction	CS	20,306	18,464	1	783	482	47	11	21	47	449
59	910	Misc. Cust Serv. & Info	CS	294,682	267,950	20	11,367	6,999	686	152	305	686	6,517
60		Subtotal		559,353	508,611	38	21,576	13,285	1,302	289	579	1,302	12,370
61		Sales											
62	911	Supervision	SALES										
63	912	Demonstrating & Selling	SALES										
64	913	Advertising	SALES										
65	916	Misc. Sales	SALES										
66		Subtotal											
67		Prorated Operating Expenses											
68		Administrative & General											
69	920	Administrative & General		1,204,266									
70	921	Office Supplies & Expenses		272,065									
71	922	Admin. Expenses Transferred											
72	923	Outside Services Employed		66,292									
73	924	Property Insurance											
74	925	Injuries & Damages		156,238									
75	926	Employee Pensions & Benefits		915									
76	927	Franchise Requirements											
77	928	Regulatory Commission Exp.		53,233									
78	929	Duplicate Charges		(125,454)									
79	930.1	General Advertising		259,482									
80	930.2	Misc.		517,532									
81	931	Rents		16,752									
82	935	Maint. of General Plant		317,371									
83		Accounts 920-935		2,738,691									
84		Power Supply	EX6-PS										
85		Transmission	EX6-TR										
86		Distribution	EX6-D	2,738,691	2,281,254	101	115,043	126,047	58,681	92,702	9,998	5,720	49,145
87		Subtotal - A&G		2,738,691	2,281,254	101	115,043	126,047	58,681	92,702	9,998	5,720	49,145

Allocation of Revenue Requirements to Rate Classes -- BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
88	408	**Other Taxes**											
89		Power Supply	EX6-PS										
90		Transmission	EX6-TR										
91		Distribution	EX6-D	138,361	115,251	5	5,812	6,368	2,965	4,683	505	289	2,483
92		Subtotal - Other Taxes		138,361	115,251	5	5,812	6,368	2,965	4,683	505	289	2,483
93	421-	**Miscellaneous Expense**											
94	426,431	Power Supply	EX6-PS										
95		Transmission	EX6-TR										
96		Distribution	EX6-D	352,722	293,808	13	14,817	16,234	7,558	11,939	1,288	737	6,329
97		Subtotal - Misc. Expense		352,722	293,808	13	14,817	16,234	7,558	11,939	1,288	737	6,329
98		**Fixed Charges**											
99	403-	**Depreciation**											
100	407	Power Supply	PROPLNT										
101		Transmission	TRNPLNT										
102		Distribution	DSTPLNT	9,214,432	7,674,576	203	383,263	410,567	205,493	329,560	33,581	14,187	163,001
103		Subtotal - Depreciation		9,214,432	7,674,576	203	383,263	410,567	205,493	329,560	33,581	14,187	163,001
104	408	**Property Taxes**											
105		Power Supply	PROPLNT										
106		Transmission	TRNPLNT										
107		Distribution	DSTPLNT										
108		Subtotal - Property Taxes											
109													
110		Total Oper. Expenses		98,820,490	70,645,236	2,085	4,167,767	11,225,603	4,155,331	6,657,365	652,919	276,974	1,037,211
111													
112	427	**Interest-LT**											
113		Power Supply	PROPLNT										
114		Transmission	TRNPLNT										
115		Distribution	DSTPLNT	4,525,476	3,769,208	100	188,232	201,641	100,924	161,857	16,493	6,968	80,055
116		Subtotal - Interest-LT		4,525,476	3,769,208	100	188,232	201,641	100,924	161,857	16,493	6,968	80,055
117		**Required Margin**											
118		Power Supply	PROPLNT										
119		Transmission	TRNPLNT										
120		Distribution	DSTPLNT	4,175,536	3,477,748	92	173,676	186,049	93,120	149,341	15,217	6,429	73,864
121		Subtotal - Required Margin		4,175,536	3,477,748	92	173,676	186,049	93,120	149,341	15,217	6,429	73,864
122		**Summary of Revenue Requirements**											
123		Power Supply		73,225,508	49,110,918	1,261	3,104,244	10,133,525	3,650,323	5,858,440	567,547	230,011	569,240
124		Transmission											
125		Distribution		34,295,994	28,781,273	1,017	1,425,431	1,479,769	699,051	1,110,122	117,082	60,360	621,889
123		Total Rev. Req.		107,521,502	77,892,192	2,278	4,529,674	11,613,294	4,349,374	6,968,562	684,629	290,370	1,191,129

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Rate Class Weighting Factors

I. Three Phase Vs. Single Phase Class Weighting Factors

A. Investment to Serve 3Ø vs. 1Ø Consumers (use replacement cost)

	1Ø	3Ø
1. kWh Meter	$78	$286
2. kWh Meter	$120	
3. kWh & kW Meter	$233	$441
4. kWh & kW Meter (pulse activated)	$286	$546
5. Service [1]	$259	$415
6. Transformer [2]	$1,718	$2,751
7. Primary Line [3]	$714	$1,252

B. Weighting Factors for Relative 3Ø Class Investment Costs

1. Meter (3Ø Interval Recording)	$1,200	÷	$78	=	15.38
2. Meter (3Ø w/demand, TOD)	$546	÷	$78	=	7.00
3. Meter (3Ø w/demand)	$441	÷	$78	=	5.65
4. Meter (3Ø w/o demand)	$286	÷	$78	=	3.67
5. Service	$415	÷	$259	=	1.60
6. Transformer	$2,751	÷	$1,718	=	1.60
7. Primary Line	$1,252	÷	$714	=	1.75

[1] Assume a typical installation of 80 feet of 1/0 triplex (or quadriplex), pole and miscellaneous materials to estimate the difference between a 1Ø and 3Ø installation.

[2] Use the cost difference between 1-75 kVA transformer and 3-25 kVA transformers as representative of the difference between a 1Ø versus a 3Ø transformer installation.

[3] Assume a typical installation of 150 feet of 1/0 ACSR to estimate the difference in primary line between a 1Ø and 3Ø installation.

Estimate of Class Demands Summary

Description	Total System	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	0 Outdoor Lighting Service
Class Billing Determinants										
Number of Consumers	56,648	54,076	8	2,294	250	9	2	4	9	13,152
Energy (MWh)	1,135,386	710,449	28	46,652	177,918	67,595	109,934	10,883	3,634	8,294
On-Peak Energy Sales (kWh)	559,435	345,205	4	23,535	90,999	34,808	56,610	5,604	1,840	829
Off-Peak Energy Sales (kWh)	575,952	365,244	23	23,117	86,918	32,787	53,324	5,279	1,794	7,465
Billing Demand (kW)	920,480	-	-	-	557,060	146,008	188,885	28,527	-	-
Estimated Demand Responsibility										
Non-Coincident Consumer Demand	1,312,990	1,168,817	85	33,699	64,956	15,464	17,574	2,901	1,252	8,243
Non-Coincident Class Demand	236,755	163,378	6	11,597	20,240	13,735	22,338	2,211	734	2,516
Coincident Class Demand - Ave. Monthly	209,412	153,836	-	8,625	15,086	10,469	17,026	1,686	547	2,138
Coincident Class Demand - Summer	-	-	-	-	-	-	-	-	-	-
Coincident Class Demand - Winter	-	-	-	-	-	-	-	-	-	-
Coincident Class Demand - Other	-	-	-	-	-	-	-	-	-	-
Coincident Class Demand - Weighted	209,412	153,836	-	8,625	15,086	10,469	17,026	1,686	547	2,138
Coincident Class Demand - Transm.	-	-	-	-	-	-	-	-	-	-

Description	Total System	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule 1(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
Demand Responsibility Used in Model										
Non-Coincident Consumer Demand	1,312,990	1,168,817	85	33,699	64,956	15,464	17,574	2,901	1,252	8,243
Non-Coincident Class Demand - Ave. Monthly	236,755	163,378	6	11,597	20,240	13,735	22,338	2,211	734	2,516
Coincident Class Demand - Ave. Monthly	209,412	153,836	-	8,625	15,086	10,469	17,026	1,686	547	2,138
Coincident Class Demand - Summer	-									
Coincident Class Demand - Winter	-									
Coincident Class Demand - Other	-									
Coincident Class Demand - Weighted	209,412	153,836	-	8,625	15,086	10,469	17,026	1,686	547	2,138
Coincident Class Demand - Transm.	-									
Estimated Demand Responsibility - Traditional										
Non-Coincident Consumer Demand	814,518	667,252	61	35,320	64,956	15,464	17,574	2,901	2,748	8,243
Non-Coincident Class Demand - Ave. Monthly	243,957	162,799	14	10,200	40,417	10,682	14,230	2,087	1,011	2,516
Coincident Class Demand - Ave. Monthly	207,274	138,328	-	8,667	34,342	9,077	12,091	1,773	859	2,138
Coincident Class Demand - Summer	-	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Coincident Class Demand - Winter	-	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Coincident Class Demand - Other	-	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Coincident Class Demand - Weighted	207,274	138,328	-	8,667	34,342	9,077	12,091	1,773	859	2,138
Coincident Class Demand - Transm.	-	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Estimated Demand Responsibility - LR Method										
Test Year Billing Demand (kW)	920,480.0	n/a	n/a	n/a	557,060.0	146,008.0	188,885.0	28,527.0	n/a	n/a
Sum of Individual Customer Annual Peak Demand (kW)	1,299,743.9	1,168,816.7	85.3	33,698.9	34,511.4	22,020.7	35,813.7	3,545.5	1,251.6	-
Non-Coincident Class Demand - Peak (kW)	324,851.0	243,636.9	7.9	14,123.0	22,196.9	15,814.7	25,720.4	2,546.3	805.0	-
Non-Coincident Class Demand - Ave. Monthly (kW)	234,238.9	163,377.5	5.8	11,597.5	20,240.5	13,734.7	22,337.5	2,211.4	734.0	-
Coincident Class Demand - Ave. Monthly (Adjusted kW)	207,274.0	153,835.6	-	8,624.9	15,085.5	10,469.0	17,026.4	1,685.6	547.1	-
Coincident Class Demand - Ave. Monthly (Unadjusted kW)	213,888.0	158,744.4	-	8,900.1	15,566.9	10,803.1	17,569.7	1,739.4	564.5	-
Coincident Class Demand - Summer (kW)										
Coincident Class Demand - Winter (kW)										
Coincident Class Demand - Other (kW)										
Estimated Energy Responsibility - LR Study										
Test Year Energy Sales (kWh)	1,135,386	710,449	28	46,652	177,918	67,595	109,934	10,883	3,634	8,294
On-Peak Energy Sales (kWh)	559,435	345,205	4	23,535	90,999	34,808	56,610	5,604	1,840	829
Off-Peak Energy Sales (kWh)	575,952	365,244	23	23,117	86,918	32,787	53,324	5,279	1,794	7,465
Number of Consumers										
Test Year Number of Consumers (Ave. Annual) [1]	56,644	54,076	8	2,294	250	9	2	4	9	13,152
Per Consumer Use Per Day		35.99	9.47	55.72	1,949.78	20,576.86	150,594.30	7,454.37	1,106.15	1.73
Scaling Factor		96.55%	60.61%	96.76%	95.17%	777.87%	5692.98%	281.80%	95.88%	
Line Loss (as % of Sales)		4.27%	4.27%	4.27%	4.27%	4.27%	4.27%	4.27%	4.27%	4.27%

[1] The total number of consumers excludes number of Residential Off-Peak Marketing and Street Lights.

EKPC Load Research

	Group#1 ID	RS2	RS1	Small Comm	Med Comm	MC3	MC3	MC3	Med Comm	
LR Group 1										
Weighting	Percent	100%	100%	75%	40%	100%	100%	100%	100%	100%
Per Consumer Use Per Day		37.28	15.62	66.20	1,153.74	2,645.27	2,645.27	2,645.27	1,153.74	-
Sum of Individual Customer Annual Peak Demand (kW/cons.)		21.47	16.87	14.56	139.11	301.66	301.66	301.66	139.11	-
Non-Coincident Class Demand - Peak (kW/cons.)		4.48	1.56	6.10	89.47	216.64	216.64	216.64	89.47	-
Non-Coincident Class Demand - Ave. Monthly (kW/cons.)		3.00	1.16	5.01	81.58	188.15	188.15	188.15	81.58	-
Coincident Class Demand - Ave. Monthly (kW/cons.)		2.92		3.85	62.75	147.99	147.99	147.99	62.75	-
Coincident Class Demand - Summer (kW/cons.)		2.13		3.69	55.07	121.33	121.33	121.33	55.07	-
Coincident Class Demand - Winter (kW/cons.)		3.48		3.95	68.23	167.03	167.03	167.03	68.23	-
Coincident Class Demand - Other (kW/cons.)		-	-	-	-	-	-	-	-	-
On-Peak Energy (kWh %)		0.49	0.15	0.50	0.51	0.51	0.51	0.51	0.51	0.10
Off-Peak Energy (kWh %)		0.51	0.85	0.50	0.49	0.49	0.49	0.49	0.49	0.90
	Group#2 ID			SC1	MC3					
LR Group 2										
Weighting	Percent			25%	60%					
Per Consumer Use Per Day		-	-	31.75	2,645.27	-	-	-	-	-
Sum of Individual Customer Annual Peak Demand (kW/cons.)		-	-	10.15	301.66	-	-	-	-	-
Non-Coincident Class Demand - Peak (kW/cons.)		-	-	4.48	216.64	-	-	-	-	-
Non-Coincident Class Demand - Ave. Monthly (kW/cons.)		-	-	2.92	188.15	-	-	-	-	-
Coincident Class Demand - Ave. Monthly (kW/cons.)		-	-	1.58	147.99	-	-	-	-	-
Coincident Class Demand - Summer (kW/cons.)		-	-	1.41	121.33	-	-	-	-	-
Coincident Class Demand - Winter (kW/cons.)		-	-	1.69	167.03	-	-	-	-	-
Coincident Class Demand - Other (kW/cons.)		-	-	-	-	-	-	-	-	-
On-Peak Energy (kWh %)		-	-	0.52	0.51	-	-	-	-	-
Off-Peak Energy (kWh %)		-	-	0.48	0.49	-	-	-	-	-
LR Group Total	Percent	100%	100%	100%	100%	100%	100%	100%	100%	100%
Per Consumer Use Per Day		37.28	15.62	57.58	2,048.65	2,645.27	2,645.27	2,645.27	1,153.74	-
Sum of Individual Customer Annual Peak Demand (kW/cons.)		21.47	16.87	13.46	236.64	301.66	301.66	301.66	139.11	-
Non-Coincident Class Demand - Peak (kW/cons.)		4.48	1.56	5.70	165.77	216.64	216.64	216.64	89.47	-
Non-Coincident Class Demand - Ave. Monthly (kW/cons.)		3.00	1.16	4.49	145.52	188.15	188.15	188.15	81.58	-
Coincident Class Demand - Ave. Monthly (kW/cons.)		2.92	-	3.28	113.89	147.99	147.99	147.99	62.75	-
Coincident Class Demand - Summer (kW/cons.)		2.13	-	3.12	94.83	121.33	121.33	121.33	55.07	-
Coincident Class Demand - Winter (kW/cons.)		3.48	-	3.39	127.51	167.03	167.03	167.03	68.23	-
Coincident Class Demand - Other (kW/cons.)		-	-	-	-	-	-	-	-	-
On-Peak Energy (kWh %)		0.49	0.15	0.50	0.51	0.51	0.51	0.51	0.51	0.10
Off-Peak Energy (kWh %)		0.51	0.85	0.50	0.49	0.49	0.49	0.49	0.49	0.90

Development of Allocation Factors -- BUNDLED

Line No.	Description	Units	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
1	**Allocation Factor Input Data**											
2	**Energy**											
3	Energy Sales -- All	MWh	1,135,386	710,449	28	46,652	177,918	67,595	109,934	10,883	3,634	8,294
4	Energy Sales -- On-Peak	MWh	558,308	345,205	4	23,336	90,072	34,808	56,610	5,604	1,840	829
5	Energy Sales -- Off-Peak	MWh	577,079	365,244	23	23,316	87,846	32,787	53,324	5,279	1,794	7,465
6	Dist. Losses	MWh	4.27%	4.27%	4.27%	4.27%	4.27%	4.27%	4.27%	4.27%	4.27%	4.27%
7	Energy -- All @ Sub.	MWh	1,183,875	740,790	29	48,644	185,516	70,482	114,629	11,348	3,789	8,648
8	Energy -- On-Peak @ Sub.	MWh	582,151	359,948	4	24,332	93,918	36,294	59,027	5,844	1,918	865
9	Energy -- Off-Peak @ Sub.	MWh	601,724	380,842	24	24,312	91,597	34,188	55,601	5,504	1,871	7,783
10	Energy Sales	MWh										
11	Energy -- All @ Sched. E	MWh	987,416	740,790	29	48,644	185,516				3,789	8,648
12	Energy -- On-Peak @ Source	MWh	480,986	359,948	4	24,332	93,918				1,918	865
13	Energy -- Off-Peak @ Source	MWh	506,430	380,842	24	24,312	91,597				1,871	7,783
14	**Demand**											
15	Non-Coinc. Demand @ Cons.	kW	1,312,990	1,168,817	85	33,699	64,956	15,464	17,574	2,901	1,252	8,243
16	Class Non-Coinc. Demand @ Sub.	kW	236,755	163,378	6	11,597	20,240	13,735	22,338	2,211	734	2,516
17	Class Non-Coinc. Demand Transm.	kW										
18	Summer Coinc. Demand	kW										
19	Winter Coinc. Demand	kW										
20	Other Coinc. Demand	kW										
21	Coinc. Demand @ Sub.	kW	209,412	153,836		8,625	15,086	10,469	17,026	1,686	547	2,138
22	Coinc. Demand @ Sub Sched. E	kW	180,231	153,836		8,625	15,086				547	2,138
23	**Average and Excess Demand**											
24	Average Demand	kW	135,146	84,565	3	5,553	21,178	8,046	13,085	1,295	433	987
25	Class Excess Demand	kW	101,609	78,812	3	6,044	(937)	5,689	9,252	916	302	1,529
26	Allocated Excess Demand	kW	74,266	57,604	2	4,418	(685)	4,158	6,762	669	220	1,117
27	Avg. & Excess Demand	kW	209,412	142,169	5	9,971	20,493	12,204	19,848	1,965	653	2,104
28	**Revenue**											
29	Proposed Rate Revenue	$	91,360,002	70,045,555	1,363	4,478,861	14,999,519				306,759	1,527,945
30	Purchased Power Expense	$	26,052,717	13,830,293		775,401	1,356,233	3,568,927	5,726,061	554,442	49,184	192,176
31	**Consumer**											
32	No. Consumers		69,804	54,076	8	2,294	250	9	2	4	9	13,152
33	Pri. Line Weight. Factor			1.00	0.05	1.00	1.75	1.75	1.75	1.75	1.75	0.10
34	Weight. No. of Cons.		58,165.1	54,076.0	0.4	2,294.0	437.5	15.8	3.5	7.0	15.8	1,315.2
35	Transf. Weight. Factor			1.00	0.05	1.00	1.60	1.60	1.60	1.60	1.60	0.10
36	Weight. No. of Cons.		58,124.0	54,076.0	0.4	2,294.0	400.0	14.4	3.2	6.4	14.4	1,315.2
37	Service Weight. Factor			1.00	0.05	1.00	1.60	1.60	1.60	1.60	1.65	0.10
38	Weight. No. of Cons.		58,124.5	54,076.0	0.4	2,294.0	400.0	14.4	3.2	6.4	14.9	1,315.2
39	Meter Weight. Factor			1.00	0.50	1.00	5.65				15.38	0.10
40	Weight. No. of Cons.		59,240.2	54,076.0	4.0	2,294.0	1,412.5				138.5	1,315.2
41	Cons. Acct. Weight Factor			1.00	0.50	1.00	5.65	15.38	15.38	15.38	15.38	0.10
42	Weight. No. of Cons.		59,470.9	54,076.0	4.0	2,294.0	1,412.5	138.5	30.8	61.5	138.5	1,315.2

Development of Allocation Factors -- BUNDLED
(Continued)

Line No.	Description	Data Line No.	Name	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
43	Allocation Factors												
44	Energy Related												
45	Energy -- All @ Sub.	11	E1	1.000000	0.750231	0.000029	0.049264	0.187880				0.003837	0.008759
46	Energy -- On-Peak @ Sub.	8	E2	1.000000	0.748354	0.000009	0.050589	0.195262				0.003988	0.001798
47	Energy -- Off-Peak @ Sub.	9	E3	1.000000	0.752013	0.000048	0.048006	0.180869				0.003694	0.015369
48	Energy -- All @ Sched. E	11	E4	1.000000	0.750231	0.000029	0.049264	0.187880				0.003837	0.008759
49	Energy -- On-Peak @ Source	12	E5	1.000000	0.748354	0.000009	0.050589	0.195262				0.003988	0.001798
50	Energy -- Off-Peak @ Source	13	E6	1.000000	0.752013	0.000048	0.048006	0.180869				0.003694	0.015369
51													
52	Demand Related												
53	Non-coinc. Demand @ Cons.	15	D1	1.000000	0.890195	0.000065	0.025666	0.049472	0.011777	0.013384	0.002210	0.000953	0.006278
54	Non-coinc. Demand @ Class	16	D2	1.000000	0.690071	0.000025	0.048985	0.085491	0.058012	0.094349	0.009340	0.003100	0.010626
55	Non-coinc. Demand @ Transm	17	D3										
56	Summer Coinc. Demand	18	D4										
57	Winter Coinc. Demand	19	D5										
58	Other Coinc. Demand	20	D6										
59	Coinc. Demand @ Sub.	22	D7	1.000000	0.853549		0.047855	0.083701				0.003035	0.011860
60	Coinc. Demand @ Source	22	D8	1.000000	0.853549		0.047855	0.083701				0.003035	0.011860
61	Avg. & Excess	27	D9	1.000000	0.678898	0.000025	0.047614	0.097858	0.058277	0.094779	0.009383	0.003118	0.010049
62													
63	Revenue Related												
64	Proposed Rate Revenue	29	R1	1.000000	0.766698	0.000015	0.049024	0.164180				0.003358	0.016724
65	Purchased Power Expense	30	PP	1.000000	0.530858		0.029763	0.052057	0.136989	0.219787	0.021282	0.001888	0.007376
66													
67	Consumer Related												
68	No. of Cons.	32	C1	1.000000	0.774683	0.000115	0.032863	0.003581	0.000129	0.000029	0.000057	0.000129	0.188413
69	Pri. Line Weight. Cons.	34	C2	1.000000	0.929698	0.000007	0.039439	0.007522	0.000271	0.000060	0.000120	0.000271	0.022611
70	Transf. Weight. Cons.	36	C3	1.000000	0.930356	0.000007	0.039467	0.006882	0.000248	0.000055	0.000110	0.000248	0.022627
71	Services Weight. Cons.	38	C4	1.000000	0.930349	0.000007	0.039467	0.006882	0.000248	0.000055	0.000110	0.000255	0.022627
72	Meter Weight. Cons.	40	C5	1.000000	0.912827	0.000068	0.038724	0.023844				0.002337	0.022201
73	Cons. Acct. Weight. Cons.	42	C6	1.000000	0.909285	0.000067	0.038573	0.023751	0.002328	0.000517	0.001035	0.002328	0.022115

Adjusted Statement of Operations and Revenue Requirements

(a) Line No.	(b) Description	(c) Total System [1]	(d) Adjustment [2]	(e) Adjusted System
	Operating Revenue	($)	($)	($)
1	Rate Schedule Revenue	139,466,149	(41,103,803)	98,362,346
2	Other Operating Revenue	1,874,169		1,874,169
3	Total Operating Revenue	141,340,318	(41,103,803)	100,236,515
4	**Operating Expenses**			
5	Purchased Power Expense			
6	Substation	1,396,716	-	1,396,716
7	Transmission	-		-
8	Demand	16,203,287		16,203,287
9	Energy			-
10	On-Peak Energy	25,091,122		25,091,122
11	Off-Peak Energy	20,684,954		20,684,954
12	Revenue Related Charges	-		-
13	Schedule B Demand Charges	1,773,742		1,773,742
14	Schedule B Energy Charges	8,075,688		8,075,688
15	Schedule B ESR Charges	-		-
16	Contract Charges	40,866,817	(40,866,817)	-
17				-
18				-
19	Transmission - O&M Expense	-		-
20	Distribution - Operation Expense	5,379,575	(39,498)	5,340,077
21	Distribution - Maintenance Expense	3,863,514	(39,498)	3,824,016
22	Consumer Accounting Expense	3,427,328		3,427,328
23	Consumer Service & Information Expense	559,353		559,353
24	Sales Expense	-		-
25	Administrative & General Expense	2,778,189	(39,498)	2,738,691
26	Depreciation & Amortization Expense	9,253,930	(39,498)	9,214,432
27	Property Tax Expense	-		-
28	Other Tax Expense	138,361		138,361
29	Other Interest Expense	282,323		282,323
30	Other Deductions	70,399		70,399
31	**Total Operating Expenses** (Before Long			
32	Term Interest)	139,845,297	(41,024,808)	98,820,490
33	Long Term Interest	4,564,974	(39,498)	4,525,476
34	Required Margin [3]	4,215,034	(39,498)	4,175,536
35	**Revenue Requirements**	148,625,305	(41,103,803)	107,521,502

[1] See Exhibit II, page 1.

[2] See the following page for calculation of adjustments to exclude classes from the class cost of service analysis.

[3] Required Net Operating Income less Long Term Interest. See calculation below:
$5,171,816 - 4,564,974 = $606,842

Adjustment to Eliminate Revenue and Expenses of Classes not included in the Class Cost of Service Study

1. Revenue [1]		($)	
a. Gallatin Contract	=	(41,103,803)	
b.	=		
c. **Total -- Revenue**		(41,103,803)	
2. Expenses			
a. Purchased Power [2]			
Contract Charges		(40,866,817)	
Subtotal -- Purchased Power Expenses		(40,866,817)	
b. Distribution - Operation	=	(39,498)	3
c. Distribution - Maintenance	=	(39,498)	3
d. Administrative and General	=	(39,498)	3
e. Depreciation	=	(39,498)	3
f. Interest	=	(39,498)	3
g. Margin Requirements	=	(39,498)	3
h. Subtotal		(236,986)	
i. **Total -- Expenses**		(41,103,803)	

[1] From Exhibit 2, Schedule A.
[2] From Exhibit 2, Schedule B.
[3] Split remainder of revenue approximately equal between Distribution Operation and Maintenance, Administration and General, Depreciation, Interest and Margin Requirements.

Cost of Service Summary

Revenue Requirements Summary – BUNDLED

Line No.	Description	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
1	Revenue Requirements										
2	Revenue Requirements	107,883,383	78,430,081	2,265	4,548,792	11,531,956	4,310,043	6,823,021	688,689	289,080	1,259,456
3											
4	Present Rates										
5	Revenue-Present Rates	103,484,586	70,045,555	1,363	4,478,861	14,999,519	4,757,501	6,485,816	881,267	306,759	1,527,945
6	Revenue Credits	1,874,169	1,268,568	25	81,115	271,650	86,161	117,462	15,960	5,556	27,672
7		105,358,755	71,314,123	1,388	4,559,976	15,271,169	4,843,662	6,603,278	897,227	312,315	1,555,617
8											
9	Difference	2,524,628	7,115,959	877	(11,184)	(3,739,213)	(533,619)	219,743	(208,539)	(23,235)	(296,161)
10	As Percent	2.4%	10.2%	64.4%	(0.2%)	(24.9%)	(11.2%)	3.4%	(23.7%)	(7.6%)	(19.4%)

Cost of Service Summary
Class Allocation Summary – BUNDLED

Line No.	Category	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
20	Power Supply										
21	Direct and Revenue Related										
22	Wholesale Cost	6,096,547	4,047,984	79	258,837	866,833	320,076	437,528	59,182	17,728	88,301
23	Allocated Cost										
24	Subtotal	6,096,547	4,047,984	79	258,837	866,833	320,076	437,528	59,182	17,728	88,301
25	Capacity Related										
26	Wholesale Cost	18,283,132	14,204,836		796,399	1,392,962	659,305	852,918	128,815	50,516	197,380
27	Allocated Cost										
28	Subtotal	18,283,132	14,204,836		796,399	1,392,962	659,305	852,918	128,815	50,516	197,380
29	Energy Related										
30	Wholesale Cost	48,022,182	30,583,806	1,139	2,011,945	7,678,845	2,564,276	4,312,989	372,759	156,829	339,596
31	Allocated Cost										
32	Subtotal	48,022,182	30,583,806	1,139	2,011,945	7,678,845	2,564,276	4,312,989	372,759	156,829	339,596
33	Sub. Power Supply	72,401,861	48,836,625	1,218	3,067,181	9,938,639	3,543,657	5,603,435	560,756	225,073	625,278
34	Transmission										
35	Direct										
36	Capacity										
37	Energy										
38	Allocated Cost										
39	Sub. Transmission										
40	Distribution										
41	Direct	12,285									12,285
42	Consumer	21,749,858	20,061,277	667	851,035	300,712	14,869	3,304	6,609	23,468	487,917
43	Capacity	13,719,379	9,532,179	380	630,577	1,292,605	751,517	1,216,282	121,324	40,539	133,976
44	Energy										
45	Sub. Distribution	35,481,522	29,593,456	1,047	1,481,612	1,593,317	766,386	1,219,586	127,933	64,007	634,179
46											
47	Total	107,883,383	78,430,081	2,265	4,548,792	11,531,956	4,310,043	6,823,021	688,689	289,080	1,259,456

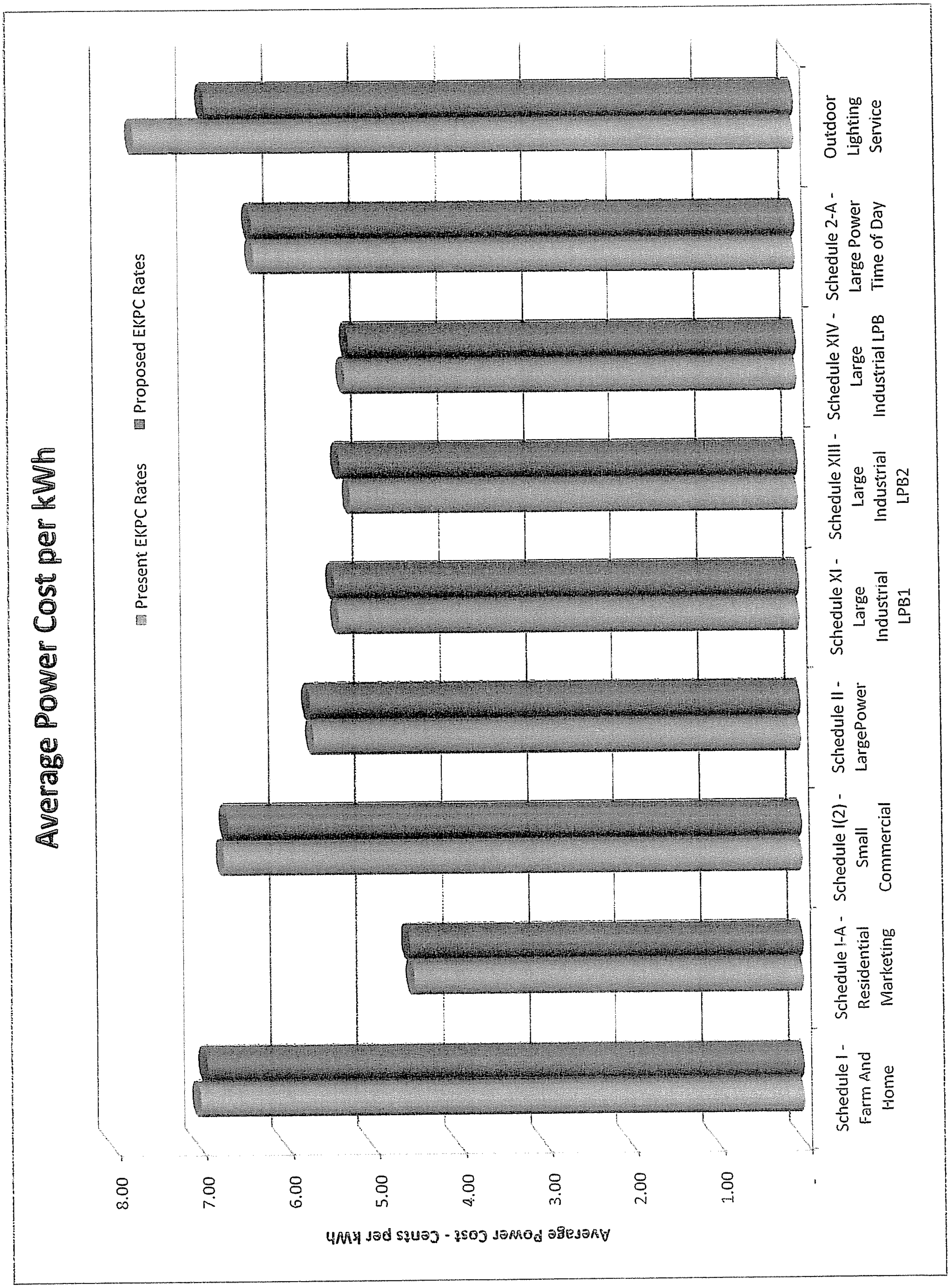
Cost of Service Summary
Rate Design Factors – BUNDLED

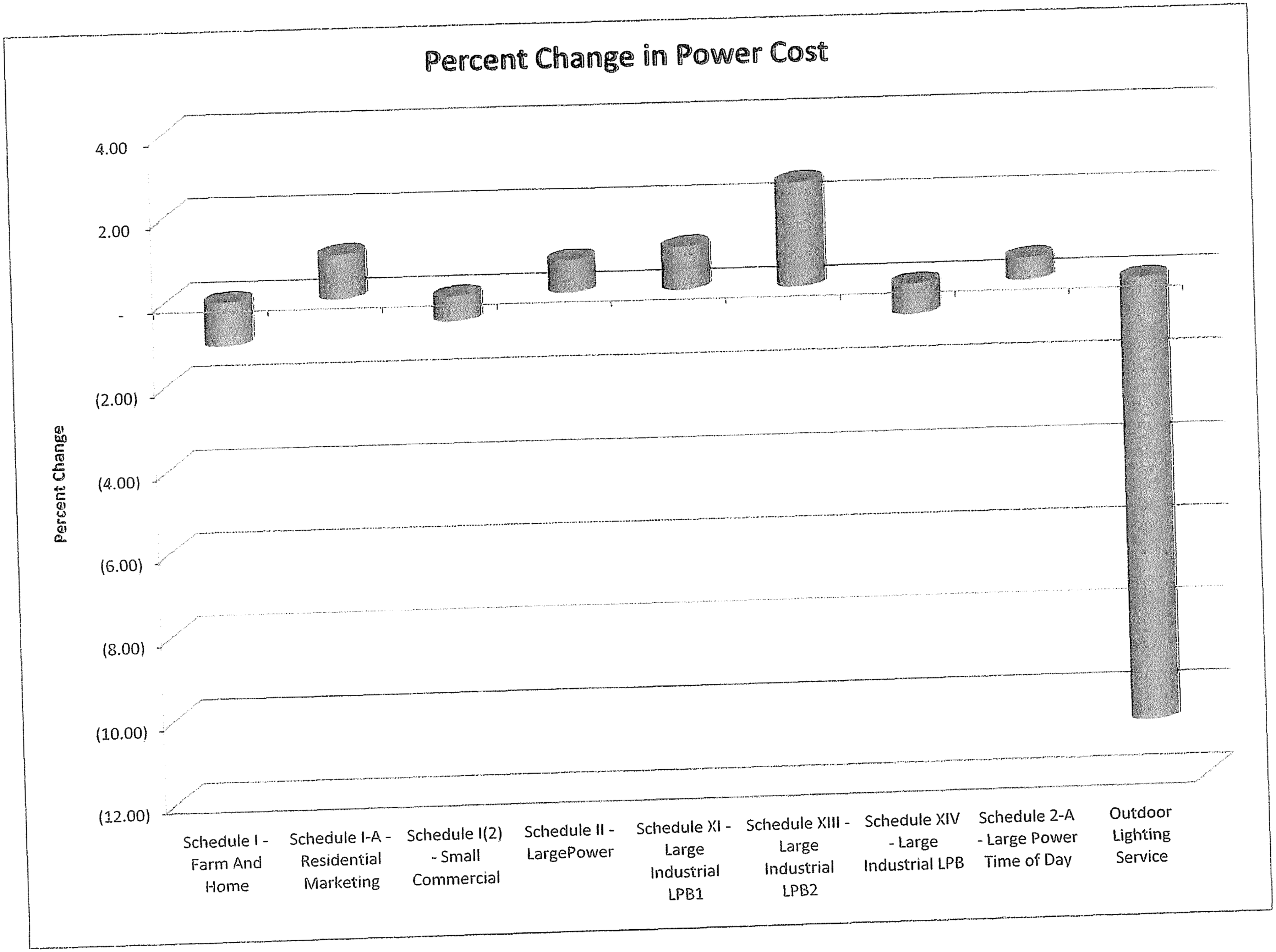
Line No.	Category	Units	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
48	**Costs Broken Down by Function**											
49	**Power Supply**											
50	Direct and Revenue Related											
51	Wholesale Cost	¢/kWh	0.54	0.57	0.28	0.55	0.49	0.47	0.40	0.54	0.49	1.06
52	Allocated Cost	¢/kWh										
53	Subtotal		0.54	0.57	0.28	0.55	0.49	0.47	0.40	0.54	0.49	1.06
54	Capacity Related											
55	Wholesale Cost	¢/kWh	1.61	2.00		1.71	0.78	0.98	0.78	1.18	1.39	2.38
56	Allocated Cost	¢/kWh										
57	Subtotal	¢/kWh	1.61	2.00		1.71	0.78	0.98	0.78	1.18	1.39	2.38
58	Energy Related											
59	Wholesale Cost	¢/kWh	4.23	4.30	4.12	4.31	4.32	3.79	3.92	3.43	4.32	4.09
60	Allocated Cost	¢/kWh										
61	Subtotal	¢/kWh	4.23	4.30	4.12	4.31	4.32	3.79	3.92	3.43	4.32	4.09
62	Sub. Power Supply	¢/kWh	6.38	6.87	4.41	6.57	5.59	5.24	5.10	5.15	6.19	7.54
63	**Transmission**											
64	Direct	¢/kWh										
65	Capacity	¢/kWh										
66	Energy	¢/kWh										
67	Allocated Cost	¢/kWh										
68	Sub. Transmission	¢/kWh										
69	**Distribution**											
70	Direct	$/Mo./cons	0.02									0.08
71	Consumer	$/Mo./cons	31.99	30.92	6.95	30.92	100.24	137.68	137.68	137.68	217.29	3.09
72	Capacity	¢/kWh	1.21	1.34	1.37	1.35	0.73	1.11	1.11	1.11	1.12	1.62
73	Energy	¢/kWh										
74	Sub. Distribution	¢/kWh	3.13	4.17	3.79	3.18	0.90	1.13	1.11	1.18	1.76	7.65
75	Total	¢/kWh	9.50	11.04	8.19	9.75	6.48	6.38	6.21	6.33	7.96	15.18
76	**Costs Broken Down by Classification**											
77	Direct	¢/kWh	0.54	0.57	0.28	0.55	0.49	0.47	0.40	0.54	0.49	1.21
78	Consumer	$/Mo./cons	31.99	30.92	6.95	30.92	100.24	137.68	137.68	137.68	217.29	3.09
79	Capacity	¢/kWh	2.82	3.34	1.37	3.06	1.51	2.09	1.88	2.30	2.51	4.00
80	Energy	¢/kWh	4.23	4.30	4.12	4.31	4.32	3.79	3.92	3.43	4.32	4.09
81	Total		9.50	11.04	8.19	9.75	6.48	6.38	6.21	6.33	7.96	15.18

Owen Electric Cooperative
Impact of Wholesale Rate Changes on Total Power Cost and By Rate Class

Line No.	Description		Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
1	**Power Cost Summary**											
2	Present Wholesale Rates											
3	Direct and Revenue Related	$	6,096,547	4,047,984	79	258,837	866,833	320,076	437,528	59,182	17,728	88,301
4	Substation Charges	$	1,185,528	804,852	29	56,448	116,014	69,089	112,363	11,124	3,696	11,914
5	Capacity Related	$	18,283,132	14,204,836	0	796,399	1,392,962	659,305	852,918	128,815	50,516	197,380
6	Energy Related	$	48,022,182	30,583,806	1,139	2,011,945	7,678,845	2,564,276	4,312,989	372,759	156,829	339,596
7	Total	$	73,587,389	49,641,478	1,247	3,123,628	10,054,653	3,612,745	5,715,797	571,880	228,769	637,191
8												
9	Proposed Wholesale Rates											
10	Direct and Revenue Related	$	0	0	0	0	0	0	0	0	0	0
11	Substation Charges	$	1,396,716	948,227	34	66,503	136,680	81,396	132,379	13,105	4,355	14,036
12	Capacity Related	$	17,977,029	13,830,293	0	775,401	1,356,233	712,620	921,890	139,232	49,184	192,176
13	Energy Related	$	53,851,763	34,332,398	1,226	2,262,340	8,640,611	2,856,307	4,804,171	415,210	176,472	363,028
14	Total	$	73,225,508	49,110,918	1,261	3,104,244	10,133,525	3,650,323	5,858,440	567,547	230,011	569,240
15												
16	Change In Power Cost											
17	Direct and Revenue Related	$	(6,096,547)	(4,047,984)	(79)	(258,837)	(866,833)	(320,076)	(437,528)	(59,182)	(17,728)	(88,301)
18	Substation Charges	$	211,188	143,375	5	10,055	20,666	12,307	20,016	1,982	658	2,122
19	Capacity Related	$	(306,103)	(374,543)	0	(20,999)	(36,729)	53,315	68,972	10,417	(1,332)	(5,204)
20	Energy Related	$	5,829,581	3,748,593	87	250,395	961,767	292,031	491,182	42,451	19,643	23,432
21	Total	$	(361,881)	(530,559)	13	(19,385)	78,872	37,578	142,643	(4,332)	1,241	(67,951)
22												
23	**Power Cost per kWh**											
24	Present Wholesale Rates											
25	Direct and Revenue Related	¢/kWh	0.54	0.57	0.28	0.55	0.49	0.47	0.40	0.54	0.49	1.06
26	Substation Charges	¢/kWh	0.10	0.11	0.11	0.12	0.07	0.10	0.10	0.10	0.10	0.14
27	Capacity Related	¢/kWh	1.61	2.00	0.00	1.71	0.78	0.98	0.78	1.18	1.39	2.38
28	Energy Related	¢/kWh	4.23	4.30	4.12	4.31	4.32	3.79	3.92	3.43	4.32	4.09
29	Total	¢/kWh	6.48	6.99	4.51	6.70	5.65	5.34	5.20	5.25	6.30	7.68
30												
31	Proposed Wholesale Rates											
32	Direct and Revenue Related	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	Substation Charges	¢/kWh	0.12	0.13	0.12	0.14	0.08	0.12	0.12	0.12	0.12	0.17
34	Capacity Related	¢/kWh	1.58	1.95	0.00	1.66	0.76	1.05	0.84	1.28	1.35	2.32
35	Energy Related	¢/kWh	4.74	4.83	4.44	4.85	4.86	4.23	4.37	3.82	4.86	4.38
36	Total	¢/kWh	6.45	6.91	4.56	6.65	5.70	5.40	5.33	5.21	6.33	6.86
37												
38	Change In Power Cost											
39	Direct and Revenue Related	¢/kWh	(0.54)	(0.57)	(0.28)	(0.55)	(0.49)	(0.47)	(0.40)	(0.54)	(0.49)	(1.06)
40	Substation Charges	¢/kWh	0.02	0.02	0.02	0.02	0.01	0.02	0.02	0.02	0.02	0.03
41	Capacity Related	¢/kWh	(0.03)	(0.05)	0.00	(0.05)	(0.02)	0.08	0.06	0.10	(0.04)	(0.06)
42	Energy Related	¢/kWh	0.51	0.53	0.31	0.54	0.54	0.43	0.45	0.39	0.54	0.28
43	Total	¢/kWh	(0.03)	(0.07)	0.05	(0.04)	0.04	0.06	0.13	(0.04)	0.03	(0.82)
44												
45	**Capacity Cost per kW Billing Demand for Classes with Demand Charges**											
46	Present Wholesale Rates	$/kW		0.00	0.00	0.00	2.50	4.52	4.52	4.52	0.00	0.00
47	Proposed Wholesale Rates	$/kW		0.00	0.00	0.00	2.43	4.88	4.88	4.88	0.00	0.00
48	Change	$/kW		0.00	0.00	0.00	(0.07)	0.37	0.37	0.37	0.00	0.00
49												
50	**Percent Change in Power Cost**											
51	Direct and Revenue Related	%	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)
52	Substation Charges	%	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8
53	Capacity Related	%	(1.7)	(2.6)	0.0	(2.6)	(2.6)	8.1	8.1	8.1	(2.6)	(2.6)
54	Energy Related	%	12.1	12.3	7.6	12.4	12.5	11.4	11.4	11.4	12.5	6.9
55	Total	%	(0.5)	(1.1)	1.1	(0.6)	0.8	1.0	2.5	(0.8)	0.5	(10.7)

Exhibit 6
Page 2 of 3




Percent Change in Power Cost
Percent Change
4.00
2.00
-
(2.00)
(4.00)
(6.00)
(8.00)
(10.00)
(12.00)
Schedule I - Farm And Home
Schedule I-A - Residential Marketing
Schedule I(2) - Small Commercial
Schedule II - LargePower
Schedule XI - Large Industrial LPB1
Schedule XIII - Large Industrial LPB2
Schedule XIV - Large Industrial LPB
Schedule 2-A - Large Power Time of Day
Outdoor Lighting Service

Comparison of
Present Rates and EKPC COS Results

		Present Rates	COS Results EKPC-present	COS Results EKPC-proposed
Schedules I: Farm and Home				
Customer Charge	/month	$10.87	$30.92	$30.87
Energy Charge	/kWh	$0.09126	$0.08210	$0.08140
Fuel Charge	/kWh	($0.00831)		
Environmental Surcharge		6.1%		
Schedules I-A: Residential Marketing				
Energy Charge	/kWh	$0.05476	$0.08190	$0.08240
Fuel Charge	/kWh	($0.00831)		
Environmental Surcharge		6.1%		
Schedule I: Small Commercial				
Customer Charge	/month	$12.83	$30.92	$30.87
Energy Charge	/kWh	$0.09118	$0.07920	$0.07890
Fuel Charge	/kWh	($0.00831)		
Environmental Surcharge		6.1%		
Schedule II: Large Power				
Customer Charge	/month	$20.50	$100.24	$100.06
Energy Charge	/kWh	$0.06891	$0.04810	$0.04860
Demand Charge	/kW	$5.90	$4.82	$4.80
Fuel Charge	/kWh	($0.00831)		
Environmental Surcharge		6.1%		
Schedule 5: Renewable Resource Power				
100 kWh Block Charge	/month	$2.75		
Schedule III: Security Lights				
120 Volts, where available	/month	$8.46		
With 1 Pole Added	/month	$10.20		
With 2 Pole Added	/month	$11.94		
With 3 Pole Added	/month	$13.68		
With 4 Pole Added	/month	$15.43		
Transformer Charge	/month	$0.67		
Fuel Charge	/kWh	($0.00831)		
Environmental Surcharge		6.1%		
Schedule XI: Large Industrial LPB1				
Customer Charge	/month	$1,464.04	$137.68	$137.37
Energy Charge - 425 Hrs per kW	/kWh	$0.05446	$0.04260	$0.04230
Energy Charge - Over 425 Hrs per k'	/kWh	$0.05038	$0.04260	$0.04230
Demand Charge - Contract Demand	/kW	$6.81	$9.66	$10.12
Demand Charge - kW > Contract De	/kW	$9.47	$9.66	$10.12
Fuel Charge	/kWh	($0.00719)		
Environmental Surcharge		7.1%		
Schedule XIII: Large Industrial Rate LPB2				
Customer Charge	/month	$2,927.05	$137.68	$137.37
Energy Charge - 425 Hrs per kW	/kWh	$0.04971	$0.04320	$0.04370
Energy Charge - Over 425 Hrs per k'	/kWh	$0.04813	$0.04320	$0.04370
Demand Charge - Contract Demand	/kW	$6.81	$10.95	$11.44
Demand Charge - kW > Contract De	/kW	$9.47		
Fuel Charge	/kWh	($0.00719)		
Environmental Surcharge		7.1%		

Comparison of
Present Rates and EKPC COS Results

		Present Rates	COS Results EKPC-present	COS Results EKPC-proposed
Schedule XIV: Large Industrial Rate LPB				
Customer Charge	/month	$1,464.00	$137.68	$137.37
Energy Charge	/kWh	$0.05600	$0.03970	$0.03820
Demand Charge - Contract Demand	/kW	$6.81	$8.77	$9.21
Demand Charge - kW > Contract De	/kW	$9.47		
Fuel Charge	/kWh	($0.00719)		
Environmental Surcharge		7.1%		
Schedule I OLS: Outdoor Lighting Service				
100 Watt HPS Area	/month	$10.12	$7.37	$6.92
Cobrahead Lighting				
100 Watt HPS	/month	$13.05	$7.37	$6.92
250 Watt HPS	/month	$17.90	$12.47	$12.18
400 Watt HPS	/month	$22.63	$17.73	$17.60
Directional Lighting				
100 Watt HPS	/month	$12.24	$7.37	$6.92
250 Watt HPS	/month	$15.25	$12.47	$12.18
400 Watt HPS	/month	$19.73	$17.73	$17.60
Pole Charges	/month	$4.69		
Fuel Charge	/kWh	($0.00831)		
Environmental Surcharge		6.1%		
Schedule II SOLS: SpecialOutdoor Lighting				
Traditional Light W/ Fiberglass Pole	/month	$12.90		
Holophane Light W/ Fiberglass Pole	/month	$15.27		
Fuel Charge	/kWh	($0.00831)		
Environmental Surcharge		6.1%		
Schedule III SOLS: SpecialOutdoor Lighting				
Facilities Charge (1.75 x total investi	/month	$0.00		
Energy Charge	/kWh	$0.063902	$0.080900	$0.083400
Fuel Charge	/kWh	($0.008305)		
Environmental Surcharge		6.1%		
Schedule 2-A: Large Power - Time of Day				
Customer Charge	/month	$59.00	$217.29	$216.86
Energy Charge - On Peak	/kWh	$0.10595	$0.07320	$0.07350
Energy Charge - Off Peak	/kWh	$0.06417	$0.07320	$0.07350
Fuel Charge	/kWh	($0.008305)		
Environmental Surcharge		7.1%		

Farm & Home Time-of-Use Rate
TOU Rate Design under EKPC TOU Definition

I. Energy Sales Pattern	Time-of-Use Definition					
Seasonality	Yes					
	First On-Peak Period		Second On-Peak Period		Weekends/Holidays Off-Peak?	
October-April	7:00 AM -	12:00 PM	5:00 PM -	10:00 PM	No	
May-September	10:00 AM -	10:00 PM	-		No	
	Off-Peak	On-Peak	Total			
Farm & Home Class	(kWh)	(kWh)	(kWh)	*Load Research Data*		
Pro Forma Test Year	381,252,264	329,196,797	710,449,061	*53.7%*	*46.3%*	*100.0%*

II. Cost of Service						
Component	PS-Capacity	PS-Energy	T-Capacity	D-Capacity	D-Consumer [1]	Total
Cost for Off-Peak Hours						
Costs for Off-Peak Hours	$0	$16,585,224		$5,203,395	$6,965,285	$ 28,753,904
All Off-Peak kWh	381,252,264	381,252,264		381,252,264	381,252,264	381,252,264
Per kWh	$0.0000	$0.0435		$0.0136	$0.0183	$0.0754
W/O Distr. Peak Costs				$0.0081		$0.0699
Costs for On-Peak Hours						
All Months						
Costs for On-Peak Hours	$13,830,293	$17,747,174		$4,492,933	$6,014,258	$ 42,084,658
All On-Peak kWh	329,196,797	329,196,797		329,196,797	329,196,797	329,196,797
Per kWh	$0.0420	$0.0539		$0.0136	$0.0183	$0.1278
W/Distr. Peak Costs				$0.0201		$0.1342

III. Example Rate Design A	Test Year Billing Units	Comparison of Rates: Farm & Home		Farm & Home TOU		Incr./(Decr.)
Access Charge	54,076	$10.87	$ 7,053,630	$10.87	$ 7,053,630	
Energy Charges	710,449,061	$0.09126	$ 64,835,581			
On-Peak Energy	329,196,797			$0.11701	$ 38,518,332	
Off-Peak Energy	381,252,264			$0.06903	$ 26,317,249	
	710,449,061		$ 71,889,211		$ 71,889,211	$ -
					as percent	0.0%

IV. Example Rate Design B	Test Year Billing Units	Comparison of Rates: Farm & Home		Farm & Home TOU		Incr./(Decr.)
Access Charge	54,076	$10.87	$ 7,053,630	$10.87	$ 7,053,630	
Energy Charges	710,449,061	$0.09126	$ 64,835,581			
On-Peak Energy	329,196,797			$0.12287	$ 40,447,981	
Off-Peak Energy	381,252,264			$0.06397	$ 24,387,601	
	710,449,061		$ 71,889,211		$ 71,889,211	$ -
					as percent	0.0%

[1] Cost of Service consumer-related costs not recovered in the Service Charge. Shared over all hours.

Farm & Home Time-of-Use Rate
TOU Rate Design under Alternative TOU Definition

I. Energy Sales Pattern	Time-of-Use Definition					
Seasonality	Yes					
	First On-Peak Period		Second On-Peak Period		Weekends/Holidays Off-Peak?	
October-April	7:00 AM - 11:00 AM		5:00 PM - 9:00 PM		No	
May-September	1:00 PM - 9:00 PM		-		No	
	Off-Peak	On-Peak	Total			
Farm & Home Class	(kWh)	(kWh)	(kWh)	Load Research Data		
Pro Forma Test Year	459,788,609	250,660,452	710,449,061	*64.7%*	*35.3%*	*100.0%*

II. Cost of Service						
Component	PS-Capacity	PS-Energy	T-Capacity	D-Capacity	D-Consumer [1]	Total
Cost for Off-Peak Hours						
Costs for Off-Peak Hours	$0	$20,819,160		$6,275,272	$8,400,104	$ 35,494,536
All Off-Peak kWh	459,788,609	459,788,609		459,788,609	459,788,609	459,788,609
Per kWh	$0.0000	$0.0453		$0.0136	$0.0183	$0.0772
W/O Distr. Peak Costs				$0.0081		$0.0717
Costs for On-Peak Hours						
All Months						
Costs for On-Peak Hours	$13,830,293	$13,513,238		$3,421,056	$4,579,439	$ 35,344,026
All On-Peak kWh	250,660,452	250,660,452		250,660,452	250,660,452	250,660,452
Per kWh	$0.0552	$0.0539		$0.0136	$0.0183	$0.1410
W/Distr. Peak Costs				$0.0238		$0.1511

III. Example Rate Design A	Test Year	Comparison of Rates				
	Billing Units	Farm & Home		Farm & Home TOU		Incr./(Decr.)
Access Charge	54,076	$10.87	$ 7,053,630	$10.87	$ 7,053,630	
Energy Charges	710,449,061	$0.09126	$ 64,835,581			
On-Peak Energy	250,660,452			$0.12905	$ 32,348,913	
Off-Peak Energy	459,788,609			$0.07066	$ 32,486,669	
	710,449,061		$ 71,889,211		$ 71,889,211	$ -
					as percent	0.0%

IV. Example Rate Design B	Test Year	Comparison of Rates				
	Billing Units	Farm & Home		Farm & Home TOU		Incr./(Decr.)
Access Charge	54,076	$10.87	$ 7,053,630	$10.87	$ 7,053,630	
Energy Charges	710,449,061	$0.09126	$ 64,835,581			
On-Peak Energy	250,660,452			$0.13834	$ 34,676,060	
Off-Peak Energy	459,788,609			$0.06559	$ 30,159,521	
	710,449,061		$ 71,889,211		$ 71,889,211	$ -
					as percent	0.0%

[1] Cost of Service consumer-related costs not recovered in the Service Charge. Shared over all hours.

PSE Power System
Engineering, Inc.

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Madison, WI · Minneapolis, MN · Marietta, OH · Indianapolis, IN · Sioux Falls, SD

Rebecca Witt

From: Cuellar, Marilyn [cuellarm@powersystem.org] on behalf of Macke, Rich [macker@powersystem.org]
Sent: Friday, October 01, 2010 5:15 PM
To: Mark Stallons
Cc: Rebecca Witt; Isaac.scott@ekpc.coop; lasliej@powersystem.org
Subject: EKPC Study - Final Exhibits Reflecting Proposed Wholesale Rates for EKPC
Attachments: RJM-Stallons-10-1-10.pdf

Mr. Stallons,
Please see the attached letter and exhibits concerning the EKPC rate and feasibility study.
Rich Macke

Rich Macke
Vice President, Rates and Financial Planning
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Power System
Engineering, Inc.

Via e-mail

October 1, 2010

Mr. Mark Stallons
President and CEO
Owen Electric Cooperative
P.O. Box 400
Owenton, KY 40359-0400

Subject: EKPC Study - Final Exhibits Reflecting Proposed Wholesale Rates for EKPC

Dear Mr. Stallons:

The EKPC wholesale rate design study is nearly final, and we now have a new wholesale rate design upon which to base the completion of the retail portion of the study. To that end, we have enclosed the following Owen exhibits from the Wholesale & Retail Rates Feasibility Study for your review. This includes updates to the Revenue Requirements and Cost of Service (COS) exhibits previously sent on May 7 and May 27, 2010. The updates are focused on incorporating the proposed wholesale rates for EKPC and identifying the potential impact of same on retail pricing.

- Exhibit 1 - Present Retail Rate Schedules (omitted due to volume).
- Exhibit 2 - Statement of Operations (Updated).
- Exhibit 3 - Determination of Revenue Requirements (Updated).
- Exhibit 4 - Cost of Service Analysis - EKPC Proposed Rate Design.
- Exhibit 5 - Cost of Service Analysis - EKPC Present Rate Design.
- Exhibit 6 - Cost of Service Analysis - Impact of EKPC Rate Design.
- Exhibit 7 - Comparison of Present Rates and COS Results.
- Exhibit 8 - Residential Time-of-Use Analysis.

This information will also be available on the Box.net site for your review.

Exhibit 2 - Statement of Operations (Updated)

Exhibit 2 provides a Statement of Operations for the present rates using: 1) 2009 actual figures and 2) the Pro Forma Test Year (Test Year) which reflects Owen's 2009 actual results with long-term interest expense, rate schedule revenue and purchased power expense recalculations. The long-term interest expense has been normalized by recalculating the interest expense for the short-term variable rate loans at 4.25 percent, reflecting the current FFB long-term rate. The rate schedule revenue for the Test Year has been calculated based on unit sales from 2009 at the present retail rates. This is summarized on page 2 and detailed on pages 3-4.

The calculation of Test Year purchased power expense is detailed on page 5 of Exhibit 2. We have determined the Test Year purchased power expense using the proposed EKPC wholesale rate design. Of particular note, the previously separate Environmental Surcharge Rider (ESR) is rolled into the base rates under the proposed wholesale rate design.

Exhibit 3 - Determination of Revenue Requirements (Updated)

Exhibit 3 provides the determination of the study's revenue requirements. The term revenue requirements refers to a cooperative's total cost of doing business. It is comprised of operating expenses and margin requirements. We have included two methods for determining the margin requirements: 1) a Modified Times Interest Earned Ratio method (M-TIER) and 2) a Rate of Return on Rate Base (ROR) method. Comparing the revenue generated by present rates to the revenue requirements allows for the identification of any required increase or decrease.

In our experience, the M-TIER approach is more typical and relevant for non-profit rural electric cooperatives. For that purpose, the remainder of the study is based on the M-TIER revenue requirements.

It should be noted that the study purpose is not primarily to identify any surplus or deficiency in the present rates. Rather, the primary purpose is to identify the impact that a revised EKPC wholesale rate design could have on retail COS and rate structures. For that purpose, the increase identified in Exhibit 3 will not be targeted in proposed rates in this study. Rather, this information could be updated at such time Owen prepares for its next rate application with the Kentucky Public Service Commission.

Exhibit 4 - Cost of Service Analysis - EKPC Proposed Rate Design

The summary pages from the COS analysis under EKPC's proposed wholesale rate design are included in the attached Exhibit 4. Page 1 of the COS summarizes the present rate revenue, revenue requirements and resulting required increase or (decrease) to align rates exactly with the cost of providing service for each of the rate classes. Page 2 categorizes the total class revenue requirements into Power Supply, Transmission and Distribution service functions. Furthermore, each of these major service functions may include cost components of Direct, Consumer, Capacity and Energy. Finally, page 3 uses the information detailed on page 2 to develop a per unit cost using either customers or kWh as a basis.

It should be noted that PSE views the COS results as providing an indication of where rates should generally be and as providing useful information regarding which rate classes and/or components should receive potential increases/decreases.

Exhibit 5 - Cost of Service Analysis - EKPC Present Rate Design

The summary pages from the COS analysis under EKPC's present wholesale rate design are included in the attached Exhibit 4. This is similar to the prior COS results you were previously sent, although there have been some adjustments to the purchased power expense.

Exhibit 6 - Cost of Service Analysis - Impact of EKPC Rate Design

Exhibit 6 presents information concerning the impact of the EKPC rate design on the retail COS study. This is shown on a total revenue requirement impact for the Cooperative (which includes power supply and distribution revenue requirements) and also more narrowly concerning impacts on power supply costs by retail rate class.

A summary of the impact on COS determined increase by class is shown in Table 1 below:

Table 1
Comparison of Class Cost of Service
Proposed and Present EKPC Wholesale Rate Design

Rate Class	EKPC Proposed Rate Design Incr/(Decr) Required	EKPC Proposed Rate Design As Percent	EKPC Present Rate Design Incr/(Decr) Required	EKPC Present Rate Design As Percent	Percent Change
	($)	(%)	($)	(%)	(%)
Schedule I - Farm And Home	6,578,069	9.4%	7,115,959	10.2%	-0.8%
Schedule I-A - Residential Marketing	890	65.3%	877	64.4%	0.9%
Schedule I(2) - Small Commercial	(30,302)	-0.7%	(11,184)	-0.2%	-0.4%
Schedule II - LargePower	(3,657,875)	-24.4%	(3,739,213)	-24.9%	0.5%
Schedule XI - Large Industrial LPB1	(494,288)	-10.4%	(533,619)	-11.2%	0.8%
Schedule XIII - Large Industrial LPB2	365,284	5.6%	219,743	3.4%	2.2%
Schedule XIV - Large Industrial LPB	(212,598)	-24.1%	(208,539)	-23.7%	-0.5%
Schedule 2-A - Large Power Time of Day	(21,944)	-7.2%	(23,235)	-7.6%	0.4%
Outdoor Lighting Service	(364,488)	-23.9%	(296,161)	-19.4%	-4.5%
Total Cooperative	2,162,747	2.1%	2,524,628	2.4%	-0.3%

The table above illustrates that the proposed EKPC rate design has a mixed impact on residential commercial and industrial rate classes; with some rate classes increasing in cost of service and others decreasing. Regardless, the impact is not very substantial.

Exhibit 6 also presents information on more narrowly focused changes in how power supply costs (i.e., purchased power expense) are allocated across the Cooperative's retail rate classes. Keep in mind that power supply costs represent approximately 60-70 percent of a distribution cooperative's total revenue requirement, with the remainder being distribution costs.

Exhibit 7 - Comparison of Present Rates and COS Results

Exhibit 7 provides a side-by-side comparison of the Cooperative's present retail rates with the unit cost results of the two COS analyses. While the resulting COS unit costs are not directly comparable to a "proposed" rate design, it is nonetheless useful to see how the COS under EKPC's present and proposed rate design may influence future rate design efforts and strategies. In this regard, we would note two things, both of which you are likely already aware of as are other cooperatives around the country:

1. The COS results support a dramatic increase in the present customer charge levels. Correspondingly, the results support a decrease to Energy Charges. Again, this is something that cooperatives around the country are faced with and have been since their inception; i.e., it is nothing new or shocking.
2. The COS results support an increase in Demand Charges for the demand billed rate classes especially under the proposed EKPC rate design.

It is at this point that we would advise that proper rate design should consider all generally accepted ratemaking principles, of which cost of service is only one. It is up to the Cooperative to weigh these various, and often competitive, principles in order to maintain rates that reflect its best judgment as to what is fair and equitable to the entire membership.

Exhibit 8 - Residential Time-of-Use Analysis

In our site visits, most of the EKPC member cooperatives expressed an interest in the possibility of time-of-use (TOU) rates. Exhibit 8 therefore presents example Residential TOU rates for your Cooperative.

The justification for a TOU rate lies in capturing and billing peak-related costs during peak times. Within that framework, there are endless ways cooperatives can design and structure TOU rates in terms of: seasonality, time period definitions, day of week, holidays, number of on-peak periods, shoulder peaks, etc.

We have developed example Residential TOU rates under two TOU definitions for your consideration. First, we have defined the TOU periods consistent with the EKPC wholesale rate definition. Within this scenario (see page 1 of Exhibit 8), we have developed two sets of TOU energy charges. The first captures only power supply capacity and energy costs in determining the TOU energy charge differential. The second goes a step further and also captures peak-related distribution costs included in the on-peak energy charge.[1]

The second scenario defines the TOU periods more narrowly; i.e., less on-peak hours. In doing this, it is important to consider whether the more narrowly defined on-peak definition will still capture the power supply peaks or, if not, to what extent some power supply peak costs need to

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[1] It could be argued that peak-related distribution costs are fixed and that the on-peak price signal should thus not allow for avoiding these costs.

be captured in off-peak energy charges. In this scenario we have utilized the present TOU definition of Blue Grass Energy. This on-peak definition is narrower than EKPC's; however, it would still have captured all of the power supply billing peaks in the history we examined.

We appreciate your review of the enclosed. We are drafting the report which will more thoroughly explain the study process, assumptions and results and will send a copy to you as soon as it is complete. In the meantime, please feel free to call me at (763) 783-5349 if you should have any questions.

Respectfully yours,

Richard J. Macke

Richard J. Macke
Vice President, Rates and Financial Planning

KY0591018/mmc

cc: Becky Witt, Owen
Isaac Scott, EKPC
Jeff Laslie, PSE

Enclosures

Statement of Operations
Present Rates
Test Year - 2009

(a) Line No.	(b) Description	(c) 2009 Actual	(d) Pro Forma Test Year
1	**Operating Revenue**	($)	($)
2	Rate Schedule Revenue	139,872,447 [1]	144,588,388 [1]
3	Other Operating Revenue	1,874,169	1,874,169
4	**Total Operating Revenue**	141,746,616	146,462,557
5	**Operating Expenses**		
6	Purchased Power Expense	110,001,447	114,092,325 [2]
7	Transmission - O&M Expense	-	-
8	Distribution - Operation Expense	5,379,575	5,379,575
9	Distribution - Maintenance Expense	3,863,514	3,863,514
10	Consumer Accounting Expense	3,427,328	3,427,328
11	Consumer Service & Information Expense	559,353	559,353
12	Sales Expense	-	-
13	Administrative & General Expense	2,778,189	2,778,189
14	Depreciation & Amortization Expense	9,253,930	9,253,930
15	Property Tax Expense	-	-
16	Other Tax Expense	138,361	138,361
17	Long-Term Interest Expense	4,564,974	4,564,974
18	Other Interest Expense	282,323	282,323
19	Other Deductions	70,399	70,399
20	**Total Operating Expenses**	140,319,392	144,410,269
21	**Operating Margins**	1,427,224	2,052,287
22	**Operating TIER**	1.31	1.45
23	Plus: Non-Operating Margins - Interest	96,038	96,038
24	Plus: Income (loss) from Equity Investments	-	-
25	Plus: Non-Operating Margins - Other	8,980	8,980
26	Plus: Other Capital Credits	244,923	244,923
27	**Margins Before G&T Capital Credits**	1,777,164	2,402,227
28	**Modified TIER**	1.39	1.53
29	Plus: G&T Capital Credits	3,551,381	3,551,381
30	**Patronage Capital or Margins**	5,328,545	5,953,609
31	**TIER**	2.17	2.30

[1] See Exhibit 2, Schedule A for the Pro Forma Test Year revenue.

[2] See Exhibit 2, Schedule B for the Pro Forma Test Year purchased power expense.

Schedule A
Summary of Consumers, Energy Sales, and Revenue Under Present Rates

I. Consumer and Sales Data for the Pro Forma Test Year

(a) Line No.	(b) Description	(c) Avg. No. Cons. [1]	(d) Energy Sales [1]	(e) Billing Demand [1] Non-Coinc.	(f) Coinc.	(g) Actual Revenue [1]	(h) Pro Forma Revenue [2]
			(kWh)	(kW)	(kW)	($)	($)
1	Schedules I: Farm and Home	54,076	710,449,061	NA	NA	70,124,670	70,045,555
2	Schedules I-A: Residential Marketing	8	27,641	NA	NA	1,527	1,363
3	Schedule I: Small Commercial	2,294	46,652,046	NA	NA	4,508,357	4,478,861
4	Schedule II: Large Power	250	177,917,564	557,060.0	NA	15,411,323	14,999,519
5	Schedule 5: Renewable Resource Power			NA	NA	-	
6	Schedule III: Security Lights	9,345	6,372,258	NA	NA	829,843	989,719
7	Schedule XI: Large Industrial LPB1	9	67,594,969	146,008.0	NA	4,947,049	4,757,501
8	Schedule XIII: Large Industrial Rate LPB2	2	109,933,836	188,885.0	NA	6,235,632	6,485,816
9	Schedule XIV: Large Industrial Rate LPB	4	10,883,375	28,527.0	NA	961,330	881,267
10	Schedule I OLS: Outdoor Lighting Service	3,327	1,692,936	NA	NA	416,888	455,908
11	Schedule II SOLS: SpecialOutdoor Lighting	480	228,904	NA	NA	62,465	82,318
12	Schedule III SOLS: SpecialOutdoor Lighting			NA	NA		-
13	Schedule 2-A: Large Power - Time of Day	9	3,633,704	NA	NA	300,985	306,759
14	Gallatin Contract	1	858,526,147	1,706,527.0	NA	35,984,650	41,103,803
15	**Total [3]**	56,645	1,993,912,441	2,627,007.0	-	139,784,719	144,588,388

[1] As reported by the Cooperative for 2009.
[2] See Schedule A, pages 3 - 5.
[3] The total number of consumers excludes number of Outdoor Lighting Service and Residential Marketing.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
Schedules I: Farm and Home				
Customer Charge	54,076	/month	$10.87	7,053,630
Energy Charge	710,449,061	/kWh	$0.09126	64,835,581
Fuel Charge	710,449,061	/kWh	($0.00831)	(5,900,626)
Environmental Surcharge			6.1%	4,056,970
				70,045,555
Schedules I-A: Residential Marketing				
Energy Charge	27,641	/kWh	$0.05476	1,514
Fuel Charge	27,641	/kWh	($0.00831)	(230)
Environmental Surcharge			6.1%	79
				1,363
Schedule I: Small Commercial				
Customer Charge	2,294	/month	$12.83	353,184
Energy Charge	46,652,046	/kWh	$0.09118	4,253,734
Fuel Charge	46,652,046	/kWh	($0.00831)	(387,468)
Environmental Surcharge			6.1%	259,411
				4,478,861
Schedule II: Large Power				
Customer Charge	250	/month	$20.50	61,500
Energy Charge	177,917,564	/kWh	$0.06891	12,260,299
Demand Charge	557,060	/kW	$5.90	3,286,654
Fuel Charge	177,917,564	/kWh	($0.00831)	(1,477,692)
Environmental Surcharge			6.1%	868,757
				14,999,519
Schedule III: Security Lights				
120 Volts, where available	7,760	/month	$8.46	787,795
With 1 Pole Added	1,495	/month	$10.20	182,988
With 2 Pole Added	83	/month	$11.94	11,892
With 3 Pole Added	7	/month	$13.68	1,149
With 4 Pole Added	-	/month	$15.43	-
Transformer Charge	186	/month	$0.67	1,495
Fuel Charge	6,372,258	/kWh	($0.00831)	(52,925)
Environmental Surcharge			6.1%	57,324
	9,345			989,719
Schedule XI: Large Industrial LPB1				
Customer Charge	9	/month	$1,464.04	162,508
Energy Charge - 425 Hrs per kW	61,090,580	/kWh	$0.05446	3,326,993
Energy Charge - Over 425 Hrs per kW	6,504,389	/kWh	$0.05038	327,691
Demand Charge - Contract Demand	146,008	/kW	$6.81	994,314
Demand Charge - kW > Contract Demand	12,194	/kW	$9.47	115,477
Fuel Charge	67,594,969	/kWh	($0.00719)	(486,013)
Environmental Surcharge			7.1%	316,529
				4,757,501

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
Schedule XIII: Large Industrial Rate LPB2				
Customer Charge	2	/month	$2,927.05	70,249
Energy Charge - 425 Hrs per kW	83,036,690	/kWh	$0.04971	4,127,754
Energy Charge - Over 425 Hrs per kW	26,897,146	/kWh	$0.04813	1,294,560
Demand Charge - Contract Demand	195,900	/kW	$6.81	1,334,079
Demand Charge - kW > Contract Demand	1,910	/kW	$9.47	18,088
Fuel Charge	109,933,836	/kWh	($0.00719)	(790,432)
Environmental Surcharge			7.1%	431,519
				6,485,816
Schedule XIV: Large Industrial Rate LPB				
Customer Charge	4	/month	$1,464.00	70,272
Energy Charge	10,883,375	/kWh	$0.05600	609,469
Demand Charge - Contract Demand	28,527	/kW	$6.81	194,269
Demand Charge - kW > Contract Demand	2,838	/kW	$9.47	26,876
Fuel Charge	10,883,375	/kWh	($0.00719)	(78,252)
Environmental Surcharge			7.1%	58,633
				881,267
Schedule I OLS: Outdoor Lighting Service				
100 Watt HPS Area	3,138	/month	$10.12	381,079
Cobrahead Lighting				
100 Watt HPS	25	/month	$13.05	3,915
250 Watt HPS	11	/month	$17.90	2,363
400 Watt HPS	20	/month	$22.63	5,431
Directional Lighting				
100 Watt HPS	27	/month	$12.24	3,966
250 Watt HPS	27	/month	$15.25	4,941
400 Watt HPS	77	/month	$19.73	18,231
Pole Charges	420	/month	$4.69	23,638
Fuel Charge	1,692,936	/kWh	($0.00831)	(14,061)
Environmental Surcharge			6.15%	26,406
				455,908
Schedule II SOLS: SpecialOutdoor Lighting				
Traditional Light W/ Fiberglass Pole	299	/month	$12.90	46,285
Holophane Light W/ Fiberglass Pole	181	/month	$15.27	33,166
Fuel Charge	228,904	/kWh	($0.00831)	(1,901)
Environmental Surcharge			6.15%	4,768
				82,318
Schedule III SOLS: SpecialOutdoor Lighting				
Facilities Charge (1.75 x total investment)		/month	$0.00	-
Energy Charge		/kWh	$0.063902	-
Fuel Charge		/kWh	($0.008305)	-
Environmental Surcharge			6.15%	0
				-
Schedule 2-A: Large Power - Time of Day				
Customer Charge	9	/month	$59.00	6,608
Energy Charge - On Peak	1,836,960	/kWh	$0.105948	194,622
Energy Charge - Off Peak	1,796,744	/kWh	$0.064171	115,299
Fuel Charge	3,633,704	/kWh	($0.0083055)	(30,180)
Environmental Surcharge			7.13%	20,409
				306,759

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
Special Contracts				
Gallatin				
Firm Demand	180,000.0	/kW	$6.63	1,193,400
10-Min Intter. Demand	1,426,898.0	/kW	$1.03	1,469,705
90-Min Interr. Demand	99,629.0	/kW	$2.43	242,098
Total Demand Charge	1,706,527.0			2,905,203
On-Peak Energy	211,869,199.0	/kWh	$0.04713	9,984,972
Off-Peak Energy	581,794,340.0	/kWh	$0.04384	25,508,191
Min. Energy On-Peak	18,804,206.0	/kWh	$0.01060	199,287
Min Energy Off-Peak	46,058,402.0	/kWh	$0.00731	336,871
Buy-Thru Chg, Cr On-Pk				113,084
Buy-Thru Chg, Cr Off-Pk				10,798
Energy Charge				36,153,203
Load Following Charge				325,000
FAC Charge	858,526,147.0	/kWh	($0.00231)	(1,982,920)
Distribution Demand Charge	1,706,527.0		$0.03750	63,995
Distribution Energy Charge	858,526,147.0	/kWh	$0.00029	244,680
Environmental Surcharge			9.08%	3,394,642
				41,103,803

Schedule B
Estimate of Pro Forma Test Year Purchased Power Expense

(a) Line No.	(b) Description	(c) Units [1]		(d) Rate [2]		(e) Cost
1						($)
2	Metering Point Charge	25		$350.00		105,000
3	Substation Charge	25		$4,305.72		1,291,716
4	**Rate E1**					
5	Demand Charge [3]	2,194,036.0	kW	$7.38	/kW	16,191,986
6	Power Factor Penalty					11,301
7	Energy Charges					
8	On-Peak	515,341,871	kWh	$0.05655	/kWh	29,144,644
9	Off-Peak	484,561,322	kWh	$0.05055	/kWh	24,496,513
10				Total Energy Charges		53,641,157
11	Fuel Adjustment Charge	999,903,193	kWh	($0.00787)	/kWh	(7,865,082)
12						
13	Environmental Surcharge					-
14				Total Rate E		63,376,078
15						
16	**Rate B**					
17	Minimum Demand	288,148.0	kW	$7.25	/kW	2,089,073
18	Excess Demand	8,704.0	kW	$10.15	/kW	88,346
19	Total Demand [3]	296,852.0	kW			2,177,419
20	Interuptible Demand - Firm	82,383.0	kW	($4.90)	/kW	(403,677)
21	Interuptible Demand - Discount		kW	$0.00		-
22	Energy Charges	183,971,607	kWh	$0.05126	/kWh	9,430,385
23	Fuel Adjustment Charge	183,971,607	kWh	($0.007364)	/kWh	(1,354,697)
24	Environmental Surcharge					-
25				Total Rate B		9,849,429
26						
27	**Special Contracts**					
28	**Gallatin**					
29	Firm Demand	180,000.0	kW	$6.63	/kW	1,193,400
30	10-Min Intter. Demand	1,426,898.0	kW	$1.03	/kW	1,469,705
31	90-Min Interr. Demand	99,629.0	kW	$2.43	/kW	242,098
32	Total Demand Charge	1,706,527.0				2,905,203
33	On-Peak Energy	211,869,199.0	kWh	$0.04713	/kWh	9,984,972
34	Off-Peak Energy	581,794,340.0	kWh	$0.04384	/kWh	25,508,191
35	Min. Energy On-Peak	18,784,206.0	kWh	$0.01060	/kWh	199,075
36	Min Energy Off-Peak	52,058,402.0	kWh	$0.00731	/kWh	380,755
37	Buy-Thru Chg, Cr On-Pk					113,084
38	Buy-Thru Chg, Cr Off-Pk					10,798
39	Energy Charge					36,196,875
40	Load Following Charge					325,000
41	FAC Charge	864,506,147.0	kWh	($0.00229)	/kWh	(1,982,920)
42	Environ. Surchg			9.14%		3,422,659
43				Total Gallatin		40,866,817
44						
45	**Total Test Year Purchased Power Cost**	2,048,380,947	kWh	$0.05570	/kWh	$ 114,092,325

[1] Billing units based on budget 2009

[2] Purchased Power Rates are the 2010 projected rates for East Kentucky Power Cooperative.

[3] Usage remains similar to 2009 usage.

Determination of Revenue Requirements - Summary
TIER Method

(a)	(b)	(c)	(d)
			Pro Forma Test Year
Line No.	Description	2009 Actual	Present Rates
	Financial Results From Rates	($)	($)
1	Total Revenue [1]	141,746,616	146,462,557
2	Operating Expense [1]	140,319,392	144,410,269
3	Net Operating Income [2]	1,427,224	2,052,287
4	Non-Operating Income [3]	105,017	105,017
5	Income (Loss) from Equity Investments [3]	-	-
6	Other Capital Credits [3]	244,923	244,923
7	G&T Capital Credits [3]	3,551,381	3,551,381
8	Total Margin [4]	5,328,545	5,953,609
9	Rate of Return [5]	4.49%	4.95%
10	Operating TIER [6]	1.31	1.45
11	Modified TIER [7]	1.39	1.53
12	TIER [8]	2.17	2.30
	Required Increase/(Decrease) --Modified TIER Objective		
13	Operating Expenses (excluding interest) [1]	135,754,418	139,845,295
14	Margin Requirements		
15	Interest Expense [3]	4,564,974	4,564,974
16	Target Modified TIER [9]	2.00	2.00
17	Total Margin Required (before interest) [10]	9,129,948	9,129,948
18	Less: Non-Operating Income [3]	105,017	105,017
19	Less: Income (Loss) from Equity Investments [3]	-	-
20	Less: Other Capital Credits [3]	244,923	244,923
21	Net Operating Income Required [11]	4,215,034	4,215,034
22	Total Revenue Requirements [12]	144,534,426	148,625,304
23	Revenue From Present Rates		
24	Tariff Revenue [1]	139,872,447	144,588,388
25	Other Operating Revenue [1]	1,874,169	1,874,169
26	Total Revenue [13]	141,746,616	146,462,557
27	Required Increase/(Decrease) [14]	2,787,810	2,162,747
28	Percent Increase/(Decrease) [15]	1.99	1.50

[1] See Exhibit 2.
[2] Line 1 minus Line 2.
[3] From year end Form 7.
[4] Sum of Lines 3 through 7
[5] Line 3 divided by Line 29 (on page 2).
[6] Sum of Lines 3 and 15 divided by Line 15
[7] Sum of Lines 3, 4, 5, and 15 divided by Line 15
[8] Sum of Lines 7 and 15 divided by Line 15
[9] As determined by Owen Electric Cooperative Inc..
[10] Line 15 times Line 16.
[11] Line 17 minus Lines 15 and 18 through 20.
[12] Line 13 plus Lines 15 and 21.
[13] Line 24 plus Line 25.
[14] Line 22 minus Line 26.
[15] Line 27 divided by Line 24.

Determination of Revenue Requirements Summary
Rate of Return Method
(Continued)

(a)	(b)	(c)	(d)
			Pro Forma Test Year
Line		**2009**	**Present**
No.	**Description**	**Actual**	**Rates**
	Required Increase (Decrease) --ROR Objective	($)	($)
29	Operating Expense (excluding interest) [1]	135,754,418	139,845,295
30	Margin Requirements		
31	Rate Base [2]	135,757,983	135,757,983
32	Rate of Return [3]	6.09%	6.09%
33	Required Return [4]	8,267,378	8,267,378
34	Less: Non-Operating Income [5]	105,017	105,017
35	Net Operating Income Required [6]	8,162,360	8,162,360
36	Total Revenue Requirements [7]	143,916,778	148,007,656
37	Revenue Present Rates		
38	Tariff Revenue [1]	139,872,447	144,588,388
39	Other Operating Revenue [1]	1,874,169	1,874,169
40	Total Revenue [8]	141,746,616	146,462,557
41	Required Increase (Decrease) [9]	2,170,162	1,545,099
42	Percent Increase (Decrease) [10]	1.55	1.07

1 See Exhibit 3, Page 1.
2 See Exhibit 3, page 3.
3 See Exhibit 3, page 5.
4 Line 31 times Line 32.
5 See Exhibit 3, Page 1, Line 4 plus Line 5.
6 Line 33 minus Line 35.
7 Line 29 plus Line 35.
8 Line 38 plus Line 39.
9 Line 36 minus Line 40.
10 Line 41 divided by Line 38.

Schedule A
Rate Base

(a) Line No.	(b) Description	(c) Pro Forma Test Year
		($)
1	Utility Plant in Service [1]	204,255,817
2	Construction Work in Progress [1]	3,617,437
3	Less: Accumulated Provision for Deprec. [1]	75,981,487
4	Net Plant [1]	131,891,767
5	Materials & Supplies - Electric [2]	994,264
6	Prepayments [2]	475,528
7	Working Capital [3]	5,099,401
8	Subtotal	6,569,193
9	Less: Consumer Deposits [1]	2,702,977
10	**Total Rate Base**	135,757,983

1 December 31, 2009, Form 7 amount.

2 13 - Month Average. See Schedule B.

3 See Schedule B.

Schedule B
Rate Base Calculations
Materials & Supplies - Electric Prepayments

(a) Line No.	(b) Month		(c) Materials & Supplies Electric	(d) Prepayments
			($)	($)
1	Dec	2008	1,026,017	379,544
2	Jan	2009	1,051,392	713,270
3	Feb	2009	1,027,161	632,468
4	Mar	2009	989,029	544,589
5	Apr	2009	999,315	456,107
6	May	2009	928,362	390,187
7	Jun	2009	974,984	371,111
8	Jul	2009	961,130	504,117
9	Aug	2009	993,383	513,674
10	Sep	2009	1,024,777	434,575
11	Oct	2009	1,022,309	366,835
12	Nov	2009	956,292	335,363
13	Dec	2009	971,283	540,028
14	**Total**		12,925,435	6,181,867
15	**13 - Month Average**		994,264	475,528

Schedule B
Rate Base Calculations
Working Capital
(Continued)

(a) Line No.	(b) Description	(c) Weight Factor	(d) Pro Forma Test Year Total Amount	(e) Pro Forma Test Year Weighted Amount
			($)	($)
1	Purchased Power	10/365	114,092,325	3,125,817
2	Other O&M Exp.			
3	Dist. Oper.		5,379,575	
4	Dist. Main.		3,863,514	
5	Cons. Acct.		3,427,328	
6	Cons. Serv.		559,353	
7	Sales		-	
8	Admin. & Gen.		2,778,189	
9	**Subtotal**	45/365	16,007,958	1,973,584
10	**Total Working Capital**			5,099,401

Schedule C
Composite Cost of Capital and Rate of Return

(a) Line No.	(b) Description	(c) Interest Rate	(d) Estimated Balance	(e) Annualized Interest Expense [1]	(f) Actual Percent of Total	(g) Cost of Capital	(h) Weighted Cost of Capital
	Long Term Debt	(%)	($)	($)	(%)	(%)	(%)
1	RUS	5.38%	1,396,119	75,041			
2	RUS	4.37%	1,292,753	56,493			
3	RUS	4.46%	12,952,131	577,665			
4	RUS	4.19%	6,972,821	292,161			
5	RUS	4.44%	8,921,842	396,130			
6	RUS	3.62%	1,443,033	52,238			
7	RUS	0.50%	1,450,461	7,252			
8	CFC [2]	5.64%	24,172,174	1,363,211			
9	FFB [3]	5.40%	35,600,223	1,921,593			
10	Total Long Term Debt		94,201,556	4,741,785	61.8	5.03	3.11
11	Equity [4]		58,254,456		38.2	7.80 [5]	2.98
12	Total LT Debt and Equity		152,456,012		100.0		
13	**Required Rate of Return**						6.09

[1] The Annualized Interest Expense is based on the Estimated Loan Balance multiplied by the loan interest rate.
[2] Represents Total CFC Loans and a weighted average interest rate.
[3] Represents Total FFB Loans and a weighted average interest rate.
[4] Data taken from RUS Form 7 for December 31, 2009.
[5] See Schedule E.

Schedule D
Growth Rate Calculation

(a) Line No.	(b) Year	(c) Net Plant [1]
		($)
1	2004	105,007,231
2	2005	109,777,890
3	2006	118,455,515
4	2007	126,414,703
5	2008	129,616,048
6	2009	131,891,767

The mean growth rate in Net Plant is estimated to be:

2004-2009 = 4.66%

[1] Net Plant figures are from the utility's RUS Form 7 for the years listed.

Schedule E
Cost of Equity Capital

1. Criteria & Cooperative Policy

a. Rotate capital credits on a 20 year cycle based on the Cooperative's policy.

b. Annual growth rate = 4.66%
(See Schedule D)

2. Calculation of Return on Equity Capital

$$R = \frac{(1+g)^{n+1} - (1+g)^{n}}{(1+g)^{n} - 1}$$

WHERE: R = rate of return on equity
n = number of years in rotation period
g = growth rate

$$R = \frac{1.0466^{21} - 1.0466^{20}}{1.0466^{20} - 1} = 7.80\%$$

Cost of Service Summary
Revenue Requirements Summary -- BUNDLED

Line No.	Description	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	0 Outdoor Lighting Service
1	Revenue Requirements										
2	Revenue Requirements	107,521,502	77,892,192	2,278	4,529,674	11,613,294	4,349,374	6,968,562	684,629	290,370	1,191,129
3											
4	Present Rates										
5	Revenue-Present Rates	103,484,586	70,045,555	1,363	4,478,861	14,999,519	4,757,501	6,485,816	881,267	306,759	1,527,945
6	Revenue Credits	1,874,169	1,268,568	25	81,115	271,650	86,161	117,462	15,960	5,556	27,672
7		105,358,755	71,314,123	1,388	4,559,976	15,271,169	4,843,662	6,603,278	897,227	312,315	1,555,617
8											
9	Difference	2,162,747	6,578,069	890	(30,302)	(3,657,875)	(494,288)	365,284	(212,598)	(21,944)	(364,488)
10	As Percent	2.1%	9.4%	65.3%	(0.7%)	(24.4%)	(10.4%)	5.6%	(24.1%)	(7.2%)	(23.9%)

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Cost of Service Summary
Class Allocation Summary – BUNDLED

Line No.	Category	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	0 Outdoor Lighting Service
20	Power Supply										
21	Direct and Revenue Related										
22	Wholesale Cost	0	0	0	0	0	0	0	0	0	0
23	Allocated Cost	0	0	0	0	0	0	0	0	0	0
24	Subtotal	0	0	0	0	0	0	0	0	0	0
25	Capacity Related										
26	Wholesale Cost	17,977,029	13,830,293	0	775,401	1,356,233	712,620	921,890	139,232	49,184	192,176
27	Allocated Cost	0	0	0	0	0	0	0	0	0	0
28	Subtotal	17,977,029	13,830,293	0	775,401	1,356,233	712,620	921,890	139,232	49,184	192,176
29	Energy Related										
30	Wholesale Cost	53,851,763	34,332,398	1,226	2,262,340	8,640,611	2,856,307	4,804,171	415,210	176,472	363,028
31	Allocated Cost	0	0	0	0	0	0	0	0	0	0
32	Subtotal	53,851,763	34,332,398	1,226	2,262,340	8,640,611	2,856,307	4,804,171	415,210	176,472	363,028
33	Sub. Power Supply	71,828,792	48,162,691	1,226	3,037,740	9,996,844	3,568,927	5,726,061	554,442	225,656	555,204
34	Transmission										
35	Direct	0	0	0	0	0	0	0	0	0	0
36	Capacity	0	0	0	0	0	0	0	0	0	0
37	Energy	0	0	0	0	0	0	0	0	0	0
38	Allocated Cost	0	0	0	0	0	0	0	0	0	0
39	Sub. Transmission	0	0	0	0	0	0	0	0	0	0
40	Distribution										
41	Direct	12,285	0	0	0	0	0	0	0	0	12,285
42	Consumer	21,719,241	20,033,173	666	849,843	300,179	14,836	3,297	6,594	23,421	487,233
43	Capacity	13,961,183	9,696,328	385	642,091	1,316,270	765,611	1,239,204	123,594	41,293	136,406
44	Energy	0	0	0	0	0	0	0	0	0	0
45	Sub. Distribution	35,692,710	29,729,500	1,051	1,491,934	1,616,450	780,447	1,242,501	130,187	64,714	635,925
46											
47	Total	107,521,502	77,892,192	2,278	4,529,674	11,613,294	4,349,374	6,968,562	684,629	290,370	1,191,129

Cost of Service Summary
Rate Design Factors -- BUNDLED

Line No.	Category	Units	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	0 Outdoor Lighting Service
48	Costs Broken Down by Function											
49	Power Supply											
50	Direct and Revenue Related											
51	Wholesale Cost	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52	Allocated Cost	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
53	Subtotal		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
54	Capacity Related											
55	Wholesale Cost	¢/kWh	1.58	1.95	0.00	1.66	0.76	1.05	0.84	1.28	1.35	2.32
56	Allocated Cost	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57	Subtotal	¢/kWh	1.58	1.95	0.00	1.66	0.76	1.05	0.84	1.28	1.35	2.32
58	Energy Related											
59	Wholesale Cost	¢/kWh	4.74	4.83	4.44	4.85	4.86	4.23	4.37	3.82	4.86	4.38
60	Allocated Cost	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	Subtotal	¢/kWh	4.74	4.83	4.44	4.85	4.86	4.23	4.37	3.82	4.86	4.38
62	Sub. Power Supply	¢/kWh	6.33	6.78	4.44	6.51	5.62	5.28	5.21	5.09	6.21	6.69
63	Transmission											
64	Direct	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65	Capacity	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66	Energy	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
67	Allocated Cost	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
68	Sub. Transmission	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69	Distribution											
70	Direct	$/Mo./cons	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08
71	Consumer	$/Mo./cons	31.95	30.87	6.94	30.87	100.06	137.37	137.37	137.37	216.86	3.09
72	Capacity	¢/kWh	1.23	1.36	1.39	1.38	0.74	1.13	1.13	1.14	1.14	1.64
73	Energy	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
74	Sub. Distribution	¢/kWh	3.14	4.18	3.80	3.20	0.91	1.15	1.13	1.20	1.78	7.67
75	Total	¢/kWh	9.47	10.96	8.24	9.71	6.53	6.43	6.34	6.29	7.99	14.36
76	Costs Broken Down by Classification											
77	Direct	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15
78	Consumer	$/Mo./cons	31.95	30.87	6.94	30.87	100.06	137.37	137.37	137.37	216.86	3.09
79	Capacity	¢/kWh	2.81	3.31	1.39	3.04	1.50	2.19	1.97	2.41	2.49	3.96
80	Energy	¢/kWh	4.74	4.83	4.44	4.85	4.86	4.23	4.37	3.82	4.86	4.38
81	Total		9.47	10.96	8.24	9.71	6.53	6.43	6.34	6.29	7.99	14.36

Cost of Service Summary
Revenue Requirements Summary -- BUNDLED

Line No.	Description	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	0 Outdoor Lighting Service
1	Revenue Requirements										
2	Revenue Requirements	107,883,383	78,430,081	2,265	4,548,792	11,531,956	4,310,043	6,823,021	688,689	289,080	1,259,456
3											
4	Present Rates										
5	Revenue-Present Rates	103,484,586	70,045,555	1,363	4,478,861	14,999,519	4,757,501	6,485,816	881,267	306,759	1,527,945
6	Revenue Credits	1,874,169	1,268,568	25	81,115	271,650	86,161	117,462	15,960	5,556	27,672
7		105,358,755	71,314,123	1,388	4,559,976	15,271,169	4,843,662	6,603,278	897,227	312,315	1,555,617
8											
9	Difference	2,524,628	7,115,959	877	(11,184)	(3,739,213)	(533,619)	219,743	(208,539)	(23,235)	(296,161)
10	As Percent	2.4%	10.2%	64.4%	(0.2%)	(24.9%)	(11.2%)	3.4%	(23.7%)	(7.6%)	(19.4%)

Cost of Service Summary
Class Allocation Summary – BUNDLED

Line No.	Category	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	0 Outdoor Lighting Service
20	Power Supply										
21	Direct and Revenue Related										
22	Wholesale Cost	6,096,547	4,047,984	79	258,837	866,833	320,076	437,528	59,182	17,728	88,301
23	Allocated Cost	0	0	0	0	0	0	0	0	0	0
24	Subtotal	6,096,547	4,047,984	79	258,837	866,833	320,076	437,528	59,182	17,728	88,301
25	Capacity Related										
26	Wholesale Cost	18,283,132	14,204,836	0	796,399	1,392,962	659,305	852,918	128,815	50,516	197,380
27	Allocated Cost	0	0	0	0	0	0	0	0	0	0
28	Subtotal	18,283,132	14,204,836	0	796,399	1,392,962	659,305	852,918	128,815	50,516	197,380
29	Energy Related										
30	Wholesale Cost	48,022,182	30,583,806	1,139	2,011,945	7,678,845	2,564,276	4,312,989	372,759	156,829	339,596
31	Allocated Cost	0	0	0	0	0	0	0	0	0	0
32	Subtotal	48,022,182	30,583,806	1,139	2,011,945	7,678,845	2,564,276	4,312,989	372,759	156,829	339,596
33	Sub. Power Supply	72,401,861	48,836,625	1,218	3,067,181	9,938,639	3,543,657	5,603,435	560,756	225,073	625,278
34	Transmission										
35	Direct	0	0	0	0	0	0	0	0	0	0
36	Capacity	0	0	0	0	0	0	0	0	0	0
37	Energy	0	0	0	0	0	0	0	0	0	0
38	Allocated Cost	0	0	0	0	0	0	0	0	0	0
39	Sub. Transmission	0	0	0	0	0	0	0	0	0	0
40	Distribution										
41	Direct	12,285	0	0	0	0	0	0	0	0	12,285
42	Consumer	21,749,858	20,061,277	667	851,035	300,712	14,869	3,304	6,609	23,468	487,917
43	Capacity	13,719,379	9,532,179	380	630,577	1,292,605	751,517	1,216,282	121,324	40,539	133,976
44	Energy	0	0	0	0	0	0	0	0	0	0
45	Sub. Distribution	35,481,522	29,593,456	1,047	1,481,612	1,593,317	766,386	1,219,586	127,933	64,007	634,179
46											
47	Total	107,883,383	78,430,081	2,265	4,548,792	11,531,956	4,310,043	6,823,021	688,689	289,080	1,259,456

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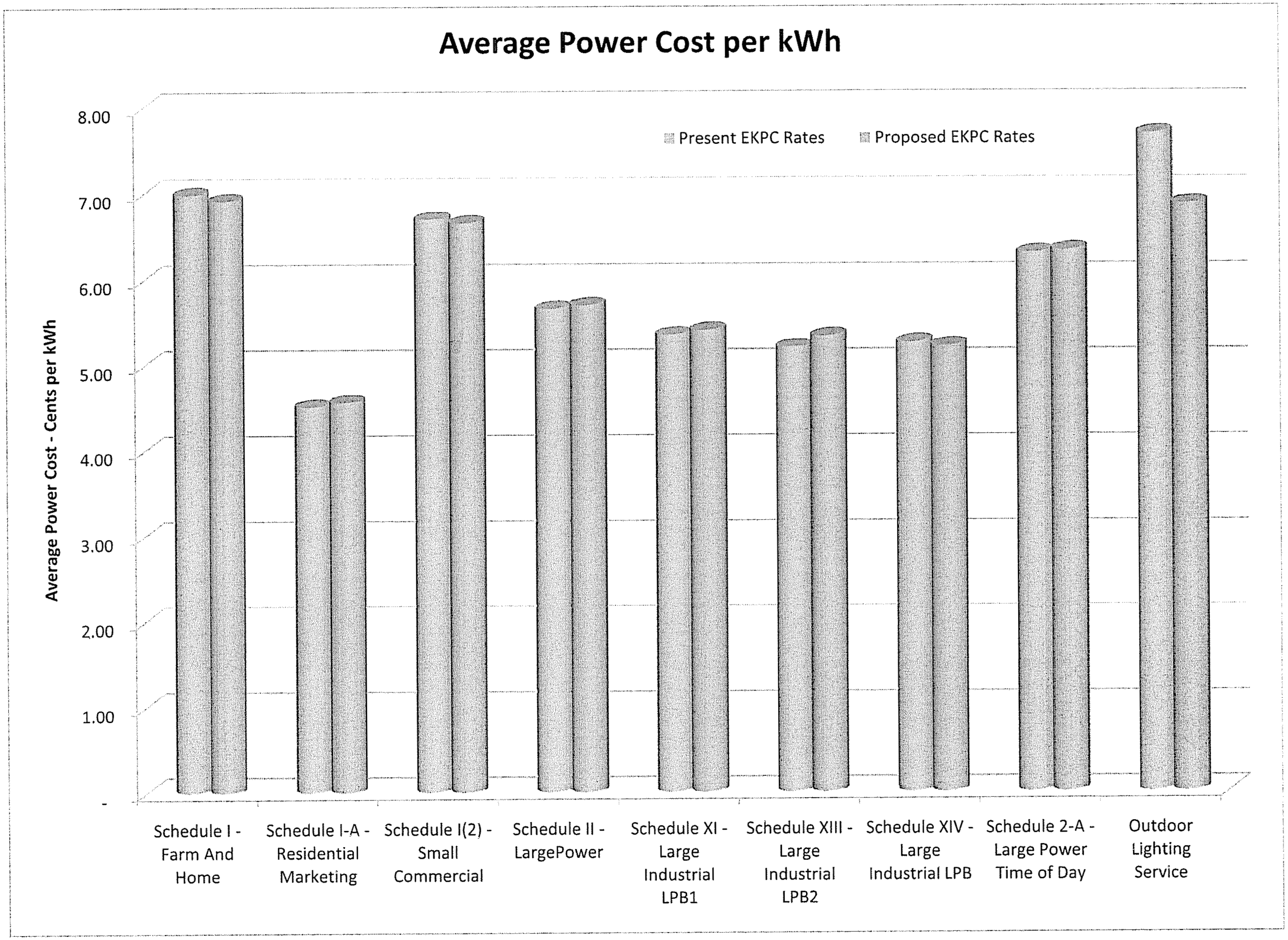
Cost of Service Summary
Rate Design Factors -- BUNDLED

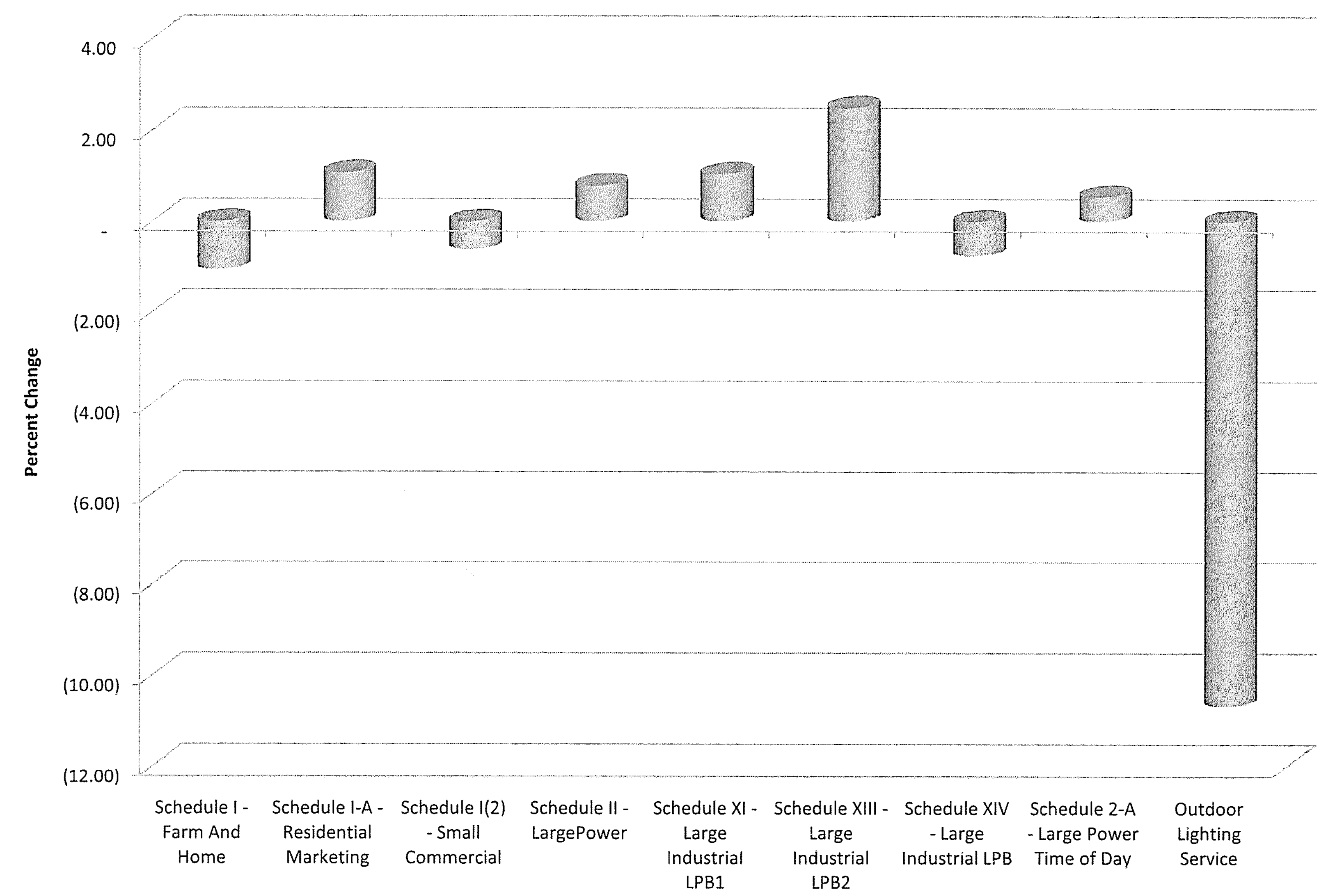
Line No.	Category	Units	Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	0 Outdoor Lighting Service
48	Costs Broken Down by Function											
49	Power Supply											
50	Direct and Revenue Related											
51	Wholesale Cost	¢/kWh	0.54	0.57	0.28	0.55	0.49	0.47	0.40	0.54	0.49	1.06
52	Allocated Cost	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
53	Subtotal		0.54	0.57	0.28	0.55	0.49	0.47	0.40	0.54	0.49	1.06
54	Capacity Related											
55	Wholesale Cost	¢/kWh	1.61	2.00	0.00	1.71	0.78	0.98	0.78	1.18	1.39	2.38
56	Allocated Cost	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57	Subtotal	¢/kWh	1.61	2.00	0.00	1.71	0.78	0.98	0.78	1.18	1.39	2.38
58	Energy Related											
59	Wholesale Cost	¢/kWh	4.23	4.30	4.12	4.31	4.32	3.79	3.92	3.43	4.32	4.09
60	Allocated Cost	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	Subtotal	¢/kWh	4.23	4.30	4.12	4.31	4.32	3.79	3.92	3.43	4.32	4.09
62	Sub. Power Supply	¢/kWh	6.38	6.87	4.41	6.57	5.59	5.24	5.10	5.15	6.19	7.54
63	Transmission											
64	Direct	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65	Capacity	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66	Energy	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
67	Allocated Cost	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
68	Sub. Transmission	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69	Distribution											
70	Direct	$/Mo./cons	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08
71	Consumer	$/Mo./cons	31.99	30.92	6.95	30.92	100.24	137.68	137.68	137.68	217.29	3.09
72	Capacity	¢/kWh	1.21	1.34	1.37	1.35	0.73	1.11	1.11	1.11	1.12	1.62
73	Energy	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
74	Sub. Distribution	¢/kWh	3.13	4.17	3.79	3.18	0.90	1.13	1.11	1.18	1.76	7.65
75	Total	¢/kWh	9.50	11.04	8.19	9.75	6.48	6.38	6.21	6.33	7.96	15.18
76	Costs Broken Down by Classification											
77	Direct	¢/kWh	0.54	0.57	0.28	0.55	0.49	0.47	0.40	0.54	0.49	1.21
78	Consumer	$/Mo./cons	31.99	30.92	6.95	30.92	100.24	137.68	137.68	137.68	217.29	3.09
79	Capacity	¢/kWh	2.82	3.34	1.37	3.06	1.51	2.09	1.88	2.30	2.51	4.00
80	Energy	¢/kWh	4.23	4.30	4.12	4.31	4.32	3.79	3.92	3.43	4.32	4.09
81	Total		9.50	11.04	8.19	9.75	6.48	6.38	6.21	6.33	7.96	15.18

Owen Electric Cooperative
Impact of Wholesale Rate Changes on Total Power Cost and By Rate Class

Line No.	Description		Total	Schedule I Farm And Home	Schedule I-A Residential Marketing	Schedule I(2) Small Commercial	Schedule II Large Power	Schedule XI Large Industrial LPB1	Schedule XIII Large Industrial LPB2	Schedule XIV Large Industrial LPB	Schedule 2-A Large Power Time of Day	Outdoor Lighting Service
1	**Power Cost Summary**											
2	Present Wholesale Rates											
3	Direct and Revenue Related	$	6,096,547	4,047,984	79	258,837	866,833	320,076	437,528	59,182	17,728	88,301
4	Substation Charges	$	1,185,528	804,852	29	56,448	116,014	69,089	112,363	11,124	3,696	11,914
5	Capacity Related	$	18,283,132	14,204,836	0	796,399	1,392,962	659,305	852,918	128,815	50,516	197,380
6	Energy Related	$	48,022,182	30,583,806	1,139	2,011,945	7,678,845	2,564,276	4,312,989	372,759	156,829	339,596
7	Total	$	73,587,389	49,641,478	1,247	3,123,628	10,054,653	3,612,745	5,715,797	571,880	228,769	637,191
8												
9	Proposed Wholesale Rates											
10	Direct and Revenue Related	$	0	0	0	0	0	0	0	0	0	0
11	Substation Charges	$	1,396,716	948,227	34	66,503	136,680	81,396	132,379	13,105	4,355	14,036
12	Capacity Related	$	17,977,029	13,830,293	0	775,401	1,356,233	712,620	921,890	139,232	49,184	192,176
13	Energy Related	$	53,851,763	34,332,398	1,226	2,262,340	8,640,611	2,856,307	4,804,171	415,210	176,472	363,028
14	Total	$	73,225,508	49,110,918	1,261	3,104,244	10,133,525	3,650,323	5,858,440	567,547	230,011	569,240
15												
16	Change In Power Cost											
17	Direct and Revenue Related	$	(6,096,547)	(4,047,984)	(79)	(258,837)	(866,833)	(320,076)	(437,528)	(59,182)	(17,728)	(88,301)
18	Substation Charges	$	211,188	143,375	5	10,055	20,666	12,307	20,016	1,982	658	2,122
19	Capacity Related	$	(306,103)	(374,543)	0	(20,999)	(36,729)	53,315	68,972	10,417	(1,332)	(5,204)
20	Energy Related	$	5,829,581	3,748,593	87	250,395	961,767	292,031	491,182	42,451	19,643	23,432
21	Total	$	(361,881)	(530,559)	13	(19,385)	78,872	37,578	142,643	(4,332)	1,241	(67,951)
22												
23	**Power Cost per kWh**											
24	Present Wholesale Rates											
25	Direct and Revenue Related	¢/kWh	0.54	0.57	0.28	0.55	0.49	0.47	0.40	0.54	0.49	1.06
26	Substation Charges	¢/kWh	0.10	0.11	0.11	0.12	0.07	0.10	0.10	0.10	0.10	0.14
27	Capacity Related	¢/kWh	1.61	2.00	0.00	1.71	0.78	0.98	0.78	1.18	1.39	2.38
28	Energy Related	¢/kWh	4.23	4.30	4.12	4.31	4.32	3.79	3.92	3.43	4.32	4.09
29	Total	¢/kWh	6.48	6.99	4.51	6.70	5.65	5.34	5.20	5.25	6.30	7.68
30												
31	Proposed Wholesale Rates											
32	Direct and Revenue Related	¢/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	Substation Charges	¢/kWh	0.12	0.13	0.12	0.14	0.08	0.12	0.12	0.12	0.12	0.17
34	Capacity Related	¢/kWh	1.58	1.95	0.00	1.66	0.76	1.05	0.84	1.28	1.35	2.32
35	Energy Related	¢/kWh	4.74	4.83	4.44	4.85	4.86	4.23	4.37	3.82	4.86	4.38
36	Total	¢/kWh	6.45	6.91	4.56	6.65	5.70	5.40	5.33	5.21	6.33	6.86
37												
38	Change In Power Cost											
39	Direct and Revenue Related	¢/kWh	(0.54)	(0.57)	(0.28)	(0.55)	(0.49)	(0.47)	(0.40)	(0.54)	(0.49)	(1.06)
40	Substation Charges	¢/kWh	0.02	0.02	0.02	0.02	0.01	0.02	0.02	0.02	0.02	0.03
41	Capacity Related	¢/kWh	(0.03)	(0.05)	0.00	(0.05)	(0.02)	0.08	0.06	0.10	(0.04)	(0.06)
42	Energy Related	¢/kWh	0.51	0.53	0.31	0.54	0.54	0.43	0.45	0.39	0.54	0.28
43	Total	¢/kWh	(0.03)	(0.07)	0.05	(0.04)	0.04	0.06	0.13	(0.04)	0.03	(0.82)
44												
45	**Capacity Cost per kW Billing Demand for Classes with Demand Charges**											
46	Present Wholesale Rates	$/kW		0.00	0.00	0.00	2.50	4.52	4.52	4.52	0.00	0.00
47	Proposed Wholesale Rates	$/kW		0.00	0.00	0.00	2.43	4.88	4.88	4.88	0.00	0.00
48	Change	$/kW		0.00	0.00	0.00	(0.07)	0.37	0.37	0.37	0.00	0.00
49												
50	**Percent Change in Power Cost**											
51	Direct and Revenue Related	%	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)
52	Substation Charges	%	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8
53	Capacity Related	%	(1.7)	(2.6)	0.0	(2.6)	(2.6)	8.1	8.1	8.1	(2.6)	(2.6)
54	Energy Related	%	12.1	12.3	7.6	12.4	12.5	11.4	11.4	11.4	12.5	6.9
55	Total	%	(0.5)	(1.1)	1.1	(0.6)	0.8	1.0	2.5	(0.8)	0.5	(10.7)


Average Power Cost per kWh
Present EKPC Rates
Proposed EKPC Rates
Average Power Cost - Cents per kWh
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
Schedule I - Farm And Home
Schedule I-A - Residential Marketing
Schedule I(2) - Small Commercial
Schedule II - LargePower
Schedule XI - Large Industrial LPB1
Schedule XIII - Large Industrial LPB2
Schedule XIV - Large Industrial LPB
Schedule 2-A - Large Power Time of Day
Outdoor Lighting Service

Percent Change in Power Cost



Comparison of
Present Rates and EKPC COS Results

		Present Rates	COS Results EKPC-present	COS Results EKPC-proposed
Schedules I: Farm and Home				
Customer Charge	/month	$10.87	$30.92	$30.87
Energy Charge	/kWh	$0.09126	$0.08210	$0.08140
Fuel Charge	/kWh	($0.00831)		
Environmental Surcharge		6.1%		
Schedules I-A: Residential Marketing				
Energy Charge	/kWh	$0.05476	$0.08190	$0.08240
Fuel Charge	/kWh	($0.00831)		
Environmental Surcharge		6.1%		
Schedule I: Small Commercial				
Customer Charge	/month	$12.83	$30.92	$30.87
Energy Charge	/kWh	$0.09118	$0.07920	$0.07890
Fuel Charge	/kWh	($0.00831)		
Environmental Surcharge		6.1%		
Schedule II: Large Power				
Customer Charge	/month	$20.50	$100.24	$100.06
Energy Charge	/kWh	$0.06891	$0.04810	$0.04860
Demand Charge	/kW	$5.90	$4.82	$4.80
Fuel Charge	/kWh	($0.00831)		
Environmental Surcharge		6.1%		
Schedule 5: Renewable Resource Power				
100 kWh Block Charge	/month	$2.75		
Schedule III: Security Lights				
120 Volts, where available	/month	$8.46		
With 1 Pole Added	/month	$10.20		
With 2 Pole Added	/month	$11.94		
With 3 Pole Added	/month	$13.68		
With 4 Pole Added	/month	$15.43		
Transformer Charge	/month	$0.67		
Fuel Charge	/kWh	($0.00831)		
Environmental Surcharge		6.1%		
Schedule XI: Large Industrial LPB1				
Customer Charge	/month	$1,464.04	$137.68	$137.37
Energy Charge - 425 Hrs per kW	/kWh	$0.05446	$0.04260	$0.04230
Energy Charge - Over 425 Hrs per k'	/kWh	$0.05038	$0.04260	$0.04230
Demand Charge - Contract Demand	/kW	$6.81	$9.66	$10.12
Demand Charge - kW > Contract De	/kW	$9.47	$9.66	$10.12
Fuel Charge	/kWh	($0.00719)		
Environmental Surcharge		7.1%		
Schedule XIII: Large Industrial Rate LPB2				
Customer Charge	/month	$2,927.05	$137.68	$137.37
Energy Charge - 425 Hrs per kW	/kWh	$0.04971	$0.04320	$0.04370
Energy Charge - Over 425 Hrs per k'	/kWh	$0.04813	$0.04320	$0.04370
Demand Charge - Contract Demand	/kW	$6.81	$10.95	$11.44
Demand Charge - kW > Contract De	/kW	$9.47		
Fuel Charge	/kWh	($0.00719)		
Environmental Surcharge		7.1%		

Comparison of
Present Rates and EKPC COS Results

		Present Rates	COS Results EKPC-present	COS Results EKPC-proposed
Schedule XIV: Large Industrial Rate LPB				
Customer Charge	/month	$1,464.00	$137.68	$137.37
Energy Charge	/kWh	$0.05600	$0.03970	$0.03820
Demand Charge - Contract Demand	/kW	$6.81	$8.77	$9.21
Demand Charge - kW > Contract De	/kW	$9.47		
Fuel Charge	/kWh	($0.00719)		
Environmental Surcharge		7.1%		
Schedule I OLS: Outdoor Lighting Service				
100 Watt HPS Area	/month	$10.12	$7.37	$6.92
Cobrahead Lighting				
100 Watt HPS	/month	$13.05	$7.37	$6.92
250 Watt HPS	/month	$17.90	$12.47	$12.18
400 Watt HPS	/month	$22.63	$17.73	$17.60
Directional Lighting				
100 Watt HPS	/month	$12.24	$7.37	$6.92
250 Watt HPS	/month	$15.25	$12.47	$12.18
400 Watt HPS	/month	$19.73	$17.73	$17.60
Pole Charges	/month	$4.69		
Fuel Charge	/kWh	($0.00831)		
Environmental Surcharge		6.1%		
Schedule II SOLS: SpecialOutdoor Lighting				
Traditional Light W/ Fiberglass Pole	/month	$12.90		
Holophane Light W/ Fiberglass Pole	/month	$15.27		
Fuel Charge	/kWh	($0.00831)		
Environmental Surcharge		6.1%		
Schedule III SOLS: SpecialOutdoor Lighting				
Facilities Charge (1.75 x total investı	/month	$0.00		
Energy Charge	/kWh	$0.063902	$0.080900	$0.083400
Fuel Charge	/kWh	($0.008305)		
Environmental Surcharge		6.1%		
Schedule 2-A: Large Power - Time of Day				
Customer Charge	/month	$59.00	$217.29	$216.86
Energy Charge - On Peak	/kWh	$0.10595	$0.07320	$0.07350
Energy Charge - Off Peak	/kWh	$0.06417	$0.07320	$0.07350
Fuel Charge	/kWh	($0.008305)		
Environmental Surcharge		7.1%		

Farm & Home Tim-of-Use Rate
TOU Rate Design under EKPC TOU Definition

I. Energy Sales Pattern	Time-of-Use Definition					
Seasonality	Yes					
	First On-Peak Period		Second On-Peak Period		Weekends/Holidays Off-Peak?	
October-April	7:00 AM - 12:00 PM		5:00 PM - 10:00 PM		No	
May-September	10:00 AM - 10:00 PM		-		No	
	Off-Peak	On-Peak	Total			
Farm & Home Class	(kWh)	(kWh)	(kWh)	*Load Research Data*		
Pro Forma Test Year	381,252,264	329,196,797	710,449,061	*53.7%*	*46.3%*	*100.0%*

II. Cost of Service						
Component	PS-Capacity	PS-Energy	T-Capacity	D-Capacity	D-Consumer[1]	Total
Cost for Off-Peak Hours						
Costs for Off-Peak Hours	$0	$16,585,224		$5,203,395	$6,965,285	$ 28,753,904
All Off-Peak kWh	381,252,264	381,252,264		381,252,264	381,252,264	381,252,264
Per kWh	$0.0000	$0.0435		$0.0136	$0.0183	$0.0754
W/O Distr. Peak Costs				$0.0081		$0.0699
Costs for On-Peak Hours						
All Months						
Costs for On-Peak Hours	$13,830,293	$17,747,174		$4,492,933	$6,014,258	$ 42,084,658
All On-Peak kWh	329,196,797	329,196,797		329,196,797	329,196,797	329,196,797
Per kWh	$0.0420	$0.0539		$0.0136	$0.0183	$0.1278
W/Distr. Peak Costs				$0.0201		$0.1342

III. Example Rate Design A	Test Year Billing Units	Comparison of Rates: Farm & Home		Farm & Home TOU		Incr./(Decr.)
Access Charge	54,076	$10.87	$ 7,053,630	$10.87	$ 7,053,630	
Energy Charges	710,449,061	$0.09126	$ 64,835,581			
On-Peak Energy	329,196,797			$0.11701	$ 38,518,332	
Off-Peak Energy	381,252,264			$0.06903	$ 26,317,249	
	710,449,061		$ 71,889,211		$ 71,889,211	$ -
					as percent	0.0%

IV. Example Rate Design B	Test Year Billing Units	Comparison of Rates: Farm & Home		Farm & Home TOU		Incr./(Decr.)
Access Charge	54,076	$10.87	$ 7,053,630	$10.87	$ 7,053,630	
Energy Charges	710,449,061	$0.09126	$ 64,835,581			
On-Peak Energy	329,196,797			$0.12287	$ 40,447,981	
Off-Peak Energy	381,252,264			$0.06397	$ 24,387,601	
	710,449,061		$ 71,889,211		$ 71,889,211	$ -
					as percent	0.0%

[1] Cost of Service consumer-related costs not recovered in the Service Charge. Shared over all hours.

Farm & Home Tim-of-Use Rate
TOU Rate Design under Alternative TOU Definition

I. Energy Sales Pattern	**Time-of-Use Definition**						
Seasonality	**Yes**						
	First On-Peak Period		**Second On-Peak Period**		**Weekends/Holidays Off-Peak?**		
October-April	**7:00 AM - 11:00 AM**		**5:00 PM - 9:00 PM**		**No**		
May-September	**1:00 PM - 9:00 PM**		-		**No**		
	Off-Peak	**On-Peak**	**Total**				
Farm & Home Class	(kWh)	(kWh)	(kWh)	*Load Research Data*			
Pro Forma Test Year	459,788,609	250,660,452	710,449,061	*64.7%*	*35.3%*	*100.0%*	

II. Cost of Service							
Component	**PS-Capacity**	**PS-Energy**	**T-Capacity**	**D-Capacity**	**D-Consumer** [1]	**Total**	
Cost for Off-Peak Hours							
Costs for Off-Peak Hours	$0	$20,819,160		$6,275,272	$8,400,104	$	35,494,536
All Off-Peak kWh	459,788,609	459,788,609		459,788,609	459,788,609		459,788,609
Per kWh	$0.0000	$0.0453		$0.0136	$0.0183		$0.0772
W/O Distr. Peak Costs				$0.0081			$0.0717
Costs for On-Peak Hours							
All Months							
Costs for On-Peak Hours	$13,830,293	$13,513,238		$3,421,056	$4,579,439	$	35,344,026
All On-Peak kWh	250,660,452	250,660,452		250,660,452	250,660,452		250,660,452
Per kWh	$0.0552	$0.0539		$0.0136	$0.0183		$0.1410
W/Distr. Peak Costs				$0.0238			$0.1511

III. Example Rate Design A	**Test Year Billing Units**	**Comparison of Rates**						
		Farm & Home			**Farm & Home TOU**			**Incr./(Decr.)**
Access Charge	54,076	$10.87	$	7,053,630	$10.87	$	7,053,630	
Energy Charges	710,449,061	$0.09126	$	64,835,581				
On-Peak Energy	250,660,452				$0.12905	$	32,348,913	
Off-Peak Energy	459,788,609				$0.07066	$	32,486,669	
	710,449,061		$	71,889,211		$	71,889,211	$ -
							as percent	0.0%

IV. Example Rate Design B	**Test Year Billing Units**	**Comparison of Rates**						
		Farm & Home			**Farm & Home TOU**			**Incr./(Decr.)**
Access Charge	54,076	$10.87	$	7,053,630	$10.87	$	7,053,630	
Energy Charges	710,449,061	$0.09126	$	64,835,581				
On-Peak Energy	250,660,452				$0.13834	$	34,676,060	
Off-Peak Energy	459,788,609				$0.06559	$	30,159,521	
	710,449,061		$	71,889,211		$	71,889,211	$ -
							as percent	0.0%

[1] Cost of Service consumer-related costs not recovered in the Service Charge. Shared over all hours.

Rebecca Witt

From: Ann Wood [ann.wood@ekpc.coop]
Sent: Wednesday, February 23, 2011 9:45 AM
To: Mark Stallons
Subject: RE: PSE Rate Study
Attachments: EKPC Wholesale COS Analysis-Rate Design-10-20-10.pdf

Mark:

The PDF file is attached.

Have a nice day,
Ann

From: Mark Stallons [mailto:mstallons@owenelectric.com]
Sent: Wednesday, February 23, 2011 9:14 AM
To: Ann Wood
Subject: PSE Rate Study

Ann:

Can you send me a pdf version of EKPC rate study compiled by PSE that we handed out at last weeks managers meeting?

Thanks,

Mark

the power to help you succeed.

East Kentucky Power Cooperative
Winchester, Kentucky

Wholesale Cost of Service Analysis and Rate Design

October 20, 2010

Power System Engineering, Inc.

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Power System Engineering, Inc.

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1.0 Introduction

1.0 Introduction

This report provides a summary of the results of an analysis of East Kentucky Power Cooperative's (EKPC) cost of providing wholesale service and rate structure applicable to its Member Distribution Cooperatives (Member-Systems). The Pro Forma Test Year used in the preparation of this analysis is based on 2009 actual results, adjusted to reflect certain major investments in production facilities, namely Spurlock No. 1 and 4, completed in 2009.

The methodology used in the cost of service (COS) analysis is generally referred to as fully allocated, average embedded, meaning that actual costs, as opposed to projected marginal costs, have been used; and all costs have been averaged across the entire system. In other words, all costs have been socialized (sometimes referred to as a "postage stamp" approach), with no attempt made to identify the cost of delivering power and energy to individual Member-Systems. The methodology used in the study is intended to be generally consistent with policies and practices of the Kentucky Public Service Commission (PSC or Commission), which we understand allows significant latitude to electric utilities in developing their proposed COS methodology.

Finally, EKPC's existing rate structure has been reviewed in light of the results of the COS. In addition, we have considered the requirements of the Energy Independence and Security Act of 2007 (EISA) in our review, specifically how the price signals provided in EKPC's wholesale rate might assist the Member-Systems in developing their individual retail rates to encourage energy efficiency objectives. Comments and suggestions for future modifications are offered relative to EKPC's current rate structure to advance EKPC and its Member-Systems' objectives.

2.0 Executive Summary

2.0 Executive Summary

2.1 Revenue Requirements

The COS analysis presented herein is based on revenue and expenses for 2009, adjusted to annualize the financial impact of two major construction projects which went into commercial operation in 2009; namely, 1) the scrubber for Spurlock No. 1, which went into service on August 1, 2009; and 2) Spurlock No. 4, which went into service on April 1, 2009. The Pro Forma Test Year used in the study also reflects the annualization of the rate change which went into effect on August 1, 2009. A comparison of the 2009 Actual and Pro Forma Operating Statements is presented below:

Table 2.1
East Kentucky Power Cooperative, Inc.
Pro Forma Test Year Operating Statement

Category	Actual	Adjustment	Total
	($000)	($000)	($000)
Operating Revenue			
Electric Energy Revenue	745,705	15,294	760,999
Other Operating Revenue	27,384	-	27,384
Total Operating Revenue	773,089	15,294	788,383
Operating Expenses			
Production	507,000	(9,850)	497,150
Transmission	29,844	-	29,844
Distribution	1,674	-	1,674
Cust. Acct., Service & Info., Sales	2,002	-	2,002
Admin & General	29,589	-	29,589
Subtotal	570,109	(9,850)	560,259
Fixed Costs			
Depreciation	60,549	3,231	63,780
Taxes	1	-	1
L.T. Interest	113,320	-	113,320
Other Interest and Deductions	7,243	-	7,243
Subtotal Fixed Costs	181,113	3,231	184,344
Total Expenses	751,222	(6,619)	744,603
Operating Margin	21,867	21,913	43,780
Non Operating Income	8,703	-	8,703
Total Margin	30,570	21,913	52,483

The revenue requirements utilized in the COS and rate design is revenue neutral on a total system basis with respect to the revenue produced by the present rates which went into effect August 1, 2009.

2.2 Cost of Service Analysis

The study presented herein includes a fully allocated, average embedded COS analysis, meaning that actual costs, with minor adjustments as explained above, were used in the analysis as opposed to projected marginal costs. In addition, except for a few minor exceptions, the total costs for the system were fully allocated to all Member-Systems and rate classes. This is sometimes referred to as a "postage stamp" approach.

Almost without question, the most critical and potentially controversial issue with respect to developing a COS for a generation and transmission (G&T) cooperative such as EKPC is how investment in production plant facilities is to be classified: capacity related, energy related, or some combination of the two. As part of this study, we investigated three alternate approaches:

1. Assign 100 percent of the investment in production facilities to the capacity component. This is the approach taken in EKPC's last rate filing, which was taken to show that EKPC's demand charge component was severely under recovered.
2. Assign approximately 72 percent of the investment in EKPC's coal-fired base load units to the energy component based on the Equivalent Peaker (EP) method. This methodology is based on the premise that if EKPC only desired capacity, it would install a peaking generating unit (i.e., a simple cycle combustion turbine). The fact that EKPC has chosen to invest substantially more capital in base load units was driven by a desire to obtain access to lower cost energy and, therefore, that incremental investment is energy related.
3. Assign approximately 61 percent of all production plant investment to the energy component based on the Average and Excess Demand (AED) method. The AED method is an alternative approach also intended to recognize the dual role that capacity and energy play in decisions to commit to new power supply resources. In this case, the percentage classified as energy related (approximately 61 percent) is based on the average system load factor, while the remaining investment is assigned to the capacity

component, and ultimately allocated to each class based on excess demand (i.e., non coincidental peak demand less that average demand).

A comparison of the results of the COS analyses under each of the three methodologies is presented in the following table:

Table 2.2
East Kentucky Power Cooperative, Inc.
Comparison of Results of Alternative COS Methodologies

Case	Total	Production Capacity	Production Energy	Steam Direct	Transm.	Dist. Substa.	Metering
	($000)	($000)	($000)	($000)	($000)	($000)	($000)
A 100% Production Assigned to Capacity							
Member Revenue Requirements	$757,909	$227,068	$444,632	$11,860	$59,182	$13,858	$ 1,310
Average Rates							
$/kW/mo		8.44			2.20		
$/MWh	63.32	18.97	37.15		4.94		
$/Substation/mo						3,701	350
B Peaker Method							
Member Revenue Requirements	$757,909	$139,263	$532,183	$12,113	$59,182	$13,858	$ 1,310
Average Rates							
$/kW/mo		5.18			2.20		
$/MWh	63.32	11.64	44.46		4.94		
$/Substation/mo						3,701	350
C Average and Excess Method							
Member Revenue Requirements	$757,909	$152,454	$519,031	$12,075	$59,182	$13,858	$ 1,310
Average Rates							
$/kW/mo		5.67			2.20		
$/MWh	63.32	12.74	43.36		4.94		
$/Substation/mo						3,701	350

We recommend that EKPC adopt the EP methodology for its COS analysis, as we believe this to be the most rational basis for recognizing the dual role that energy and capacity play in determining EKPC's resource mix. Furthermore, including the recovery of some fixed costs through the energy charge component, which is what the EP method accomplishes, dovetails nicely with the objectives of EISA; namely, the promotion of energy efficiency. Finally, an EP approach to COS analysis and rate design goes a long way toward the avoidance of overstating the demand charge component which, under the 100 percent capacity approach, could lead to uneconomic decisions for direct load control.

The final step in the COS process is to allocate the functionalized and classified costs to the various rate classes. The results of this allocation process are presented in the following table:

Table 2.3
East Kentucky Power Cooperative, Inc.
Comparison of Revenue Requirements Allocated to Each Class With Revenue Under Present Rates From Each Class

Class	Present Revenue ($000)	Revenue Requirements ($000)	Excess (Shortfall) Amount ($000)	Excess (Shortfall) Percent (%)
B	48,648	49,217	(569)	-1.2%
C	18,224	18,326	(102)	-0.6%
E	610,461	609,874	587	0.1%
G	17,533	18,259	(726)	-4.1%
Pumping Stations	9,256	9,256	-	0.0%
Inland Steam	12,921	12,113	808	6.3%
Gallatin	40,867	40,864	3	0.0%
Total	757,910	757,909	1	0.0%

2.3 Rate Design

The final section of this report addresses rate design. As a general statement, we found EKPC's present rate structure to be well founded and supported by the results of the EP-based COS analysis. Furthermore, by not overemphasizing the demand charge component, and by including a time-of-use (TOU) component in the energy charge, the present rate structure is consistent with the objectives of EISA to encourage energy efficiency. EKPC's real time pricing pilot program is also consistent with the objectives of EISA and, if successful, will add another tool to the tool box of EKPC, its Member-Systems and the ultimate retail consumers as they seek to conserve energy and control costs.

As part of this study, we analyzed the current time period definitions used to 1) create a window during which billing demand is established and 2) differentiate the on-peak and off-peak energy charges. Specifically, we addressed two questions. First, should the defined hours be changed.

Second, should weekends and holidays be excluded from the definition of the on-peak period. In both instances, we found that the current definitions continue to be appropriate.

Finally, we developed a set of "proposed rates" that are consistent with the results of the COS. We put quotes around "proposed" since these rates are based on a Pro Forma Test Year adopted for purposes of this study only; and the rates that are ultimately proposed to the Kentucky PSC will need to be based on the Test Year adopted for that case. In addition, of course, the rates proposed herein have not been approved by the EKPC Board; and, as discussed in Section 4.0, rate design is an art, not a science, subject to a balancing of a wide variety of objectives. While we have proposed a rate structure that reflects our best judgment of the balancing of these objectives, we fully recognize that it is EKPC's Board that must make the final determination. With that caveat in mind, the following provides a summary of our proposed rate structure:

Section B

		Present[1]	Proposed
Demand Charge			
Base	@	$ 7.43/kW	$ 7.25/kW
Excess	@	$10.33/kW	$10.15/kW
Energy Charge	@	$0.04255/kWh	$0.04349/kWh

Section C

		Present[1]	Proposed
Demand Charge	@	$7.43/kW	$7.10/kW
Energy Charge	@	$0.04232/kWh	$0.04325/kWh

Section E

		Present[1]	Proposed
Demand Charge	@	$6.22/kW	$7.38/kW
Energy Charge			
On-Peak	@	$0.05324/kWh	$0.04877/kWh
Off-Peak	@	$0.04421/kWh	$0.04277/kWh

---

1 Includes the environmental surcharge and average 2009 FCA, as adjusted, rolled in.

We recommend combining the two options presently offered under Section E into a single rate.

Section G

		Present[1]	Proposed
Demand Charge	@	$7.24/kW	$7.38/kW
Energy Charge	@	$0.04024/kWh	$0.04217/kWh

A comparison of the revenue under the present and proposed rates is presented in the following table:

Table 2.4
East Kentucky Power Cooperative, Inc.
Comparison of Present and Proposed Revenue - Total

Member System	Present	Proposed	Increase (Decrease) Amount	Increase (Decrease) Percent
	($)	($)	($)	(%)
Big Sandy	17,343,169	17,309,461	(33,708)	-0.2%
Blue Grass	78,703,396	78,808,499	105,103	0.1%
Clark	29,033,852	29,019,470	(14,382)	0.0%
Cumberland Valley	34,028,590	33,913,789	(114,802)	-0.3%
Farmers	31,364,560	31,222,829	(141,731)	-0.5%
Fleming Mason	67,883,823	68,401,322	517,499	0.8%
Grayson	17,814,425	17,800,470	(13,955)	-0.1%
Inter-County	29,214,205	29,244,362	30,157	0.1%
Jackson	62,892,010	62,876,093	(15,918)	0.0%
Licking Valley	17,826,624	17,786,024	(40,600)	-0.2%
Nolin	45,934,936	46,098,164	163,228	0.4%
Owen	114,454,208	114,113,125	(341,084)	-0.3%
Salt River	66,014,611	65,807,589	(207,022)	-0.3%
Shelby	27,786,323	27,864,550	78,227	0.3%
So Ky	83,665,472	83,724,240	58,769	0.1%
Taylor	33,948,828	33,913,631	(35,197)	-0.1%
Total	757,909,033	757,903,618	(5,415)	0.0%
Green Power Premium	114,934	114,934		
Total Incl Green Power	758,023,967	758,018,552	(5,415)	0.0%

3.0 Revenue Requirements

3.0 Revenue Requirements

The COS analysis presented in this report is based on revenue and expenses recorded for calendar 2009, adjusted to annualize the financial impact of 1) the scrubber for Spurlock No. 1, which went into commercial operation on August 1, 2009, and 2) Spurlock No. 4, which went into commercial operation on April 1, 2009. These adjustments include annualizing fuel, purchased energy, operation and maintenance (O&M) expense, and depreciation. In addition, EKPC implemented a rate increase and rolled $10.15/MWh into its fuel cost adjustment (FCA) base on August 1, 2009. For study purposes, the margin requirements used for the Pro Forma Test Year have been adjusted to reflect the margin that would be produced by the new rates on an annualized basis. In addition, it should be noted that the environmental surcharge and its underlying costs have been incorporated into the Pro Forma Test Year revenue requirements.

A summary of the Pro Forma Test Year Member-System revenue requirements is presented on the next page.

Table 3.1 Revenue Requirements - 2009			
Category	**Actual**	**Adjustment**	**Pro Forma Test Year**
	($000)	($000)	($000)
Operating Expense			
Production	507,000	(9,850)	497,150
Transmission	29,844	-0-	29,844
Distribution	1,676	-0-	1,676
Customer Accounting	-0-	-0-	-0-
Customer Service & Info.	1,996	-0-	1,996
Sales	6	-0-	6
Admin. & General	29,589	-0-	29,589
Subtotal – Operations	570,111	(9,850)	560,261
Fixed Costs			
Depreciation & Amortization	60,549	3,231	63,780
Taxes [2]	1	-0-	1
Subtotal - Fixed Cost	60,550	3,231	63,781
Other Interest & Deductions	7,243	-0-	7,243
Subtotal – Expenses	637,904	(6,619)	631,285
Return Requirements			
Interest on Long Term Debt	113,320	-0-	113,320
Margins	30,569	15,294	45,863
Total Return [3]	143,889	15,294	159,183
Gross Revenue Requirements	781,793	8,675	790,468
Less: Other Operating Revenue [4]	23,855	-0-	23,855
Less: Non-Operating Income [5]	8,704	-0-	8,704
Net Revenue Requirements -- Member-Systems	749,234	8,675	757,909

[2] In accordance with standard RUS procedures, property taxes have been assigned directly to the appropriate operating accounts.

[3] The term "return requirements" as used herein refers to the combination of return on debt (i.e., interest expense) and return on equity (i.e., margin).

[4] Revenue from third parties (i.e., non-Members) and other operating revenue.

[5] Includes Allowance for Funds Used During Construction.

4.0 Cost of Service Analysis

4.0 Cost of Service Analysis

4.1 Overview

The purpose of a COS analysis is twofold. First, a COS is used to allocate cost responsibility to the various rate classes. While it may be argued that EKPC has but one class of consumers (namely the Member-Systems), EKPC does have several alternative rate tariffs, in addition to its base rate tariff (Schedule E). These alternative rate tariffs are applicable to service to large commercial and industrial (C&I) customers. For purposes of this study, we have treated each of EKPC's tariff options as unique rate classes. Second, a COS breaks down total system costs into categories reflecting cost causative characteristics (e.g., demand, energy and customer), thereby providing information useful in developing cost-based rate structures.

4.2 Limitations and Uses

It is vital at the outset of this section to recognize some of the inherent limitations of a COS study. First, it must be emphasized that a COS analysis, while basically an engineering/economic evaluation of an electric utility's financial situation, is an art; not an exact science. There are many different methodologies, techniques and assumptions that have been and will continue to be advocated by rate design practitioners. Because the various philosophies and assumptions can significantly affect the result of the analysis, the results of any COS should be treated as providing an indication of the general range of class cost responsibility; not precise values.

Second, a COS analysis for a generation and transmission (G&T) cooperative such as EKPC is directed at determining the cost imposed on the G&T by the Member-Systems as a group rather than determining the cost imposed by each individual Member-System. Total system costs form the basis of the analysis, with no attempt made to determine the specific cost of serving an individual Member-System. For example, transmission/wheeling costs have been addressed on a total system basis; and no attempt has been made to identify a specific delivery path and associated cost for each delivery point. Therefore, the actual cost of delivering power and/or energy to a specific Member-System, assuming that this could be accurately determined, might or might not be entirely consistent with the cost determination calculated on an average system basis. This socialization of costs is sometimes referred to as a "postage stamp" approach.

Third, an average embedded COS analysis does not address many of the other legitimate objectives of a G&T's wholesale rate design such as Member-System acceptance, the avoidance of excessively abrupt changes from the historical rate policies of the G&T, the provision of accurate price signals based on marginal costs, etc. Nor does it recognize the need to keep the rate structure simple so that it is easily administered and understood by the Member-Systems.

With the above limitations in mind, the enclosed COS analysis can provide a useful guideline for allocating cost responsibility (i.e., revenue requirements) to each Member-System in a manner that avoids undue price discrimination.

4.3 Unbundled Cost Categories

The COS analysis is designed to unbundle EKPC's Pro Forma Test Year revenue requirements into the following functional categories:

- Power supply:
  - Capacity related; and
  - Energy related.
- Delivery:
  - Transmission Service;
  - Distribution Substation Service; and
  - Metering.

In addition, for convenience, we have created a special cost category for providing steam service to Inland Steel, since this represents a highly unique and specialized service.

4.4 Procedure

The procedure used to develop a COS for EKPC is, at least conceptually, relatively straightforward as follows:

- Step 1 - Functionalize and classify plant investment, accumulated reserves for depreciation and rate base into the categories described above in Section 4.3.[6]
- Step 2 - Functionalize and classify revenue requirements into the same categories.
- Step 3 - Develop per unit rate components that reflect the functionalized/classified costs.
- Step 4 - Allocate revenue requirements to the various rate classes.

4.5 Functionalization and Classification of Plant Investment and Revenue Requirements

4.5.1 General

The base case functionalization/classification of EKPC's plant investment and revenue requirements is provided in Exhibit A, which consists of the following schedules:

- Schedule 1 - Functionalization/Classification of Plant Investment.
- Schedule 2 - Functionalization/Classification of Labor Expense.
- Schedule 3 - Functionalization/Classification of Accumulated Reserves for Depreciation.
- Schedule 4 - Functionalization/Classification of Rate Base.
- Schedule 5 - Functionalization/Classification of Revenue Requirements.

4.5.2 Classification of Plant Investment

- Production -

The classification of plant investment for the base case may be found in Schedule 1 of Exhibit A. In the base case, we have treated all production plant as being 100 percent capacity related. This is the approach that EKPC used in its 2008 rate case filed with the Kentucky PSC. A separate analysis, provided in the workpapers, has been prepared to allocate production plant investment in Spurlock Unit Nos. 1 and 2 utilized to provide

[6] The functionalization and classification of cost are sometimes addressed as two separate steps in the process. For convenience, these steps have been combined in this study into a single step.

steam service to Inland Steel; and this allocated investment has been directly assigned to that service category.

The classification of production plant into capacity and energy related components is without a doubt the single most significant and controversial issue in developing a COS for a G&T cooperative. Simply put, is investment in production facilities capacity related, energy related, or some combination of the two? How this question is decided affects the relationship between the demand and energy charges and how the G&T's costs are shared by the Member-Systems.

Until the late 1970s and/or early 1980s, the traditional answer to this question was that the fixed costs associated with production facilities are capacity related. The argument for this position is that production plant investment and related fixed costs (e.g., interest, depreciation, property tax, insurance and margin) are a function of system investment; and system investment is driven primarily by capacity considerations (i.e., the size of the facilities). Once an investment in production facilities is made, it does not vary as a function of output (i.e., energy). Historically, many G&Ts adopted this approach to classifying production and transmission investment and related fixed costs.

In the late 1980s and early 1990s, a change in philosophy began to emerge as many regulatory bodies and some unregulated G&Ts adopted a COS methodology that classified some portion of production investment and associated fixed costs as energy related. The basic argument for this alternative view is that some production (and, in some instances, transmission) investment is driven by energy considerations, not peak demand. For example, it may be argued that the reason a utility invests in base load generating units rather than peaking generating units, which cost less to install but more to operate, is the desire to obtain access to low cost energy. Were it not for energy considerations, so the argument goes, the utility would install only peaking generation facilities such as combustion turbines (CTs) because of the lower per unit ($/kW) cost of installation. The only reason that utilities invest in base load units instead of peaking units is to gain access to low cost energy. Thus, it is argued, the cost that would have been incurred in installing a system comprised entirely of peaking units is capacity related; but the additional cost of providing a system comprised of a mix of peaking, intermediate and base load units is energy related.

The National Association of Regulatory Utility Commissioners' (NARUC) Electric Utility Cost Allocation Manual (EUCAM), dated January 1992, states it this way:

> "There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate an energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption." (Page 49)

This approach, sometimes referred to generically as the "capital substitution" theory, has been accepted by many, though not all, regulatory commissions. For example, the Minnesota Public Utilities Commission has endorsed the capital substitution theory, adopting a methodology know as the "Equivalent Peaker" (EP) method to differentiate the capacity and energy components. Under the EP method, the cost of an equivalent peaker is considered capacity related, while all other production investment in excess of that amount is considered to be energy related. The North Dakota Public Service Commission, at least for purposes of regulating Xcel Energy (Xcel), uses the same method. The Colorado Public Utilities Commission gives recognition to the capital substitution theory by utilizing the Average and Excess Demand (AED) method to allocate costs between the various classes.[7] As a further example, the Michigan Public Service Commission gives recognition to the argument that at least some of the investment in production facilities is driven by energy considerations by assigning 75 percent of the fixed cost associated with production and transmission to capacity and 25 percent to energy. In contrast, the Federal Energy Regulatory Commission (FERC),

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7 The AED method allocates a portion of "capacity" related costs on the basis of average demand (mathematically equivalent to an allocation based on energy) and a portion on the basis of peak demand.

which regulates the vast majority of the wholesale rates in the country, generally treats all production and transmission fixed costs as capacity related.

We believe that some form of the capital substitution philosophy is appropriate for G&Ts such as EKPC, who have a significant amount of investment in coal-fired, base loaded generating facilities. This is particularly important in today's environment considering the high cost of installing new base load capacity, as well as the large disparity that has long existed in the cost of energy produced by peaking compared to base load units. As part of this study, therefore, we have considered two alternative approaches that reflect the dual cost drivers, capacity and energy, of production plant investment. The first method is commonly referred to as the Equivalent Peaker (EP) method.

The NARUC EUCAM describes the EP Method as follows:

> "*Objective:* Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. They generally result in significant percentages (40 to 75 percent) of total production plant costs being classified as energy-related, with the results that energy unit costs are relative high and the revenue responsibility of high load factor classes and customers is significantly greater than indicated by pure peak demand responsibility methods.
>
> The premises of this and other peaker methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study." (Pages 52 and 53, emphasis in the original)

The specific EP methodology we have utilized may be described as follows:

- The first step is to determine the relative current (replacement) cost of types of generating resources utilized on the system in question, in this case:
    - Coal-fired Steam (Base Load); and
    - Combustion Turbine (Peaking).

This replacement cost for each unit type is expressed in terms of levelized annual fixed cost, including fixed O&M expense. Unit cost characteristics provided in the 2010 Department of Energy's (DOE) Annual Energy Outlook (AEO) are used for this purpose, since the AEO is a relatively stable, nationally recognized source of generic cost and performance data for new generating units. This data is intended to function as a reasonable proxy for the capacity-energy relationships that existed at the time the various generating units were installed. The results of this analysis, expressed except as noted in 2011$, are as follows:

	Base Load	**Peaking**
Overnight Cost in 2009 (2008$)	$2,078/kW	$653/kW
Installed Cost w/ AFUDC	$2,812/kW	$737/kW
Annual Fixed O&M	$29.57/kW	$13.00/kW
Annual Levelized Cost	$258.67/kW	$73.09/kW

- The second step is to estimate the relative percentage of the fixed cost associated with each type of resource that is capacity versus energy related (i.e., the portion of plant investment that is driven by capacity considerations versus the portion that is driven by energy considerations). This is accomplished by defining the replacement installed cost of a peaking unit (conventional combustion turbine) as 100 percent capacity related, with any additional cost assumed to be driven by energy considerations. For example, if the replacement cost of a coal-fired steam base load unit is $2,000/kW and the replacement cost of a conventional combustion turbine is $600/kW, then $600/kW of the coal-fired steam unit (30 percent) is considered capacity related, with the remaining $1,400/kW (70 percent) considered energy related. This process is repeated for each type of generating resource.
- The third step is to apply the capacity/energy percentages determined in step two to the plant investment and related fixed costs for each generating resource to establish the portion of each plant investment that is capacity versus energy related. The results of this three-step process using data from the 2010 DOE AEO report are as follows:

	Base Load	Peaking
Annual Levelized Cost	$258.67/kW	$73.09/kW
Percent Capacity	28.26%	100.00%
Percent Energy	71.35%	0.00%

The second alternate method we investigated is referred to as the Average and Excess Demand (AED) method. The NARUC EUCAM describes the AED Method as follows:

> "*Objective:* The cost of service analyst may believe that average demand rather than coincidental peak demand is a better allocator of production plant costs. The average and excess method is an appropriate method for the analyst to use. The method allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak (NCP) demands." (Page 49)

Under the AED method, a portion of production plant investment equal to the system load factor, in this case 60.9 percent, is considered energy related. The remaining 39.9 percent is considered capacity related and allocated based on excess demand (i.e., the difference between a class' NCP demand and its average demand). It should be noted that, under the AED method, the 60.9 percent is applied against total production plant investment, not just against investment in base load facilities.

An alternative COS analysis based on the EP method is presented in Exhibit B, while an alternative analysis based on the AED method is provided in Exhibit C.

- Transmission -

Investment recorded in the transmission accounts (Acct. Nos. 350 to 359) includes facilities that are included in the following categories:

- Production - Capacity;
- Transmission; and
- Distribution Meters.

The transmission investment classified as Production - Capacity represents EKPC's investment in step-up transformers and related equipment at generating stations.

In addition, EKPC has historically recorded its investment in distribution substation meters in Transmission Acct. No. 353 rather than in Distribution Acct. No. 370. This investment, identified specifically in EKPC's subaccounts, has been assigned directly to the Distribution Meter category.

- Distribution Plant -

The amounts recorded in the Distribution Plant Accounts, which represent EKPC's investment in distribution substations that serve as delivery points for the Member-Systems, have been assigned to the distribution substation category.

- General Plant -

General Plant investment represents a common cost which cannot be directly linked to any of the production, transmission or distribution categories. Consequently, this investment must be allocated rather than directly assigned to the appropriate functional categories. There are two methods that are commonly used to allocate general plant investment. One method, which is particularly appropriate for distribution utilities, is to allocate general plant investment in proportion to the classification of production, transmission and distribution plant. This treats general plant investment as an overhead adder to all other classified plant investment.

Another approach, one that we favor for generating utilities, is to allocate general plant investment in proportion to labor expense, based on the argument that general plant is primarily required to support the labor force. Many of the more significant plant categories (e.g., structure and improvements, office furniture, and equipment) are directly supportive of labor. Most regulatory commissions, including FERC, utilize a labor expense allocation methodology for general plant investment for vertically integrated investor-owned utilities (IOUs) and G&Ts with significant production facilities. For purposes of this study, we have allocated general plant investment to the various categories based on labor expense. The labor expense functionalization allocators are developed in Schedule 2 of Exhibit A.

-Intangible Plant-

EKPC has approximately $1,800,000 recorded in Acct. No. 303, an Intangible Plant account. It is our understanding that this investment is directly related to the cost of interconnections with other utilities; and, thus, we have assigned it to the transmission component. The small remainder in the Intangible Plant accounts has been assigned on the basis of the labor allocator.

- Summary -

A summary of the results of the classification of plant investment developed in Schedule 1 of Exhibits A, B and C, which reflect the three alternative approaches to classifying production plant investment, is provided below:

Table 4.1A
Classification of Plant Investment Summary
Case A - Production Plant Classified as 100% Capacity Related

Plant Category	Total	Production Capacity	Production Energy	Steam Service	Transm.	Distribution Substations	Metering
	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Intangible	1,821	2	2	-	1,817	-	-
Production	2,402,566	2,362,331	-	40,235	-	-	-
Transmission	448,996	14,430	-	-	429,824		4,742
Distribution	156,591	-	-	-	-	156,591	-
General	73,678	30,227	28,348	886	12,421	1,129	667
Total	3,083,652	2,406,990	28,350	41,121	444,062	157,720	5,409

Table 4.1B
Classification of Plant Investment Summary
Case B - Production Plant Classified Using the Equivalent Peaker Method

Plant Category	Total	Production Capacity	Production Energy	Steam Service	Transm.	Distribution Substations	Metering
	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Intangible	1,821	2	2	-	1,817	-	-
Production	2,402,565	871,005	1,487,024	44,536	-	-	-
Transmission	448,996	14,430	-	-	429,824		4,742
Distribution	156,591	-	-	-	-	156,591	-
General	73,679	30,186	28,390	886	12,421	1,129	667
Total	3,083,652	915,623	1,515,416	45,422	444,062	157,720	5,409

Table 4.1C Classification of Plant Investment Summary Case C - Production Plant Classified Using the AED Method							
Plant Category	Total	Production Capacity	Production Energy	Steam Service	Transm.	Distribution Substations	Metering
	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Intangible	1,821	2	2	-	1,817	-	-
Production	2,402,566	1,095,039	1,263,638	43,889	-	-	-
Transmission	448,996	14,430	-	-	429,824		4,742
Distribution	156,591	-	-	-	-	156,591	-
General	73,679	30,192	28,384	886	12,421	1,129	667
Total	3,083,653	1,139,663	1,292,024	44,775	444,062	157,720	5,409

4.5.3 Classification of Accumulated Reserves for Depreciation

Accumulated reserves for depreciation were classified in Schedule 3 of Exhibits A, B and C in a manner similar to the plant investment classifications. Note that EKPC, like most G&Ts, does not record the depreciation reserves in as much detail as plant investment. Therefore, it was necessary to prorate some of the summarized account categories to the more detailed categories.

Summaries of the results of the classification of accumulated reserves for depreciation for each of the three cases are provided below:

Table 4.2A Classification of Accumulated Reserves for Depreciation Case A - Production Plant Classified as 100% Capacity Related							
Plant Category	Total	Production Capacity	Production Energy	Steam Service	Transm.	Distribution Substations	Metering
	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Intangible	(588)	-	-	-	(588)	-	-
Production	(611,787)	(601,562)	-	(10,225)	-	-	-
Transmission	(134,754)	(4,292)	-	-	28,579)	-	(1,883)
Distribution	(42,845)	-	-	-	-	(42,845)	
General	(50,015)	(20,519)	(19,244)	(601)	(8,432)	(766)	(453)
Total	(839,989)	(626,373)	(19,244)	(10,826)	137,599)	(43,611)	(2,336)

Table 4.2 B Classification of Accumulated Reserves for Depreciation Case B - Production Plant Classified Using the Equivalent Peaker Method							
Plant Category	Total	Production Capacity	Production Energy	Steam Service	Transm.	Distribution Substations	Metering
	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Intangible	(588)	-	-	-	(588)	-	-
Production	(611,787)	(222,572)	(377,897)	(11,318)	-	-	-
Transmission	(134,754)	(4,292)	-	-	(128,579)	-	(1,883)
Distribution	(42,845)	-	-	-	-	(42,845)	
General	(50,015)	(20,491)	(19,272)	(601)	(8,432)	(766)	(453)
Total	(839,989)	(247,355)	(397,169)	(11,919)	(137,599)	(43,611)	(2,336)

Table 4.2 C Classification of Accumulated Reserves for Depreciation Case C - Production Plant Classified Using the AED Method							
Plant Category	Total	Production Capacity	Production Energy	Steam Service	Transm.	Distribution Substations	Metering
	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Intangible	(588)	-	-	-	(588)	-	-
Production	(611,788)	(279,506)	(321,128)	(11,154)	-	-	-
Transmission	(134,754)	(4,292)	-	-	(128,579)	-	(1,883)
Distribution	(42,845)	-	-	-	-	(42,845)	
General	(50,015)	(20,495)	(19,268)	(601)	(8,432)	(766)	(453)
Total	(839,990)	(304,293)	(340,396)	(11,755)	(137,599)	(43,611)	(2,336)

4.5.4 Classification of Rate Base

Rate Base represents a utility's total investment in plant or other instruments that is "used and useful" in providing service to its electric customers. For an IOU, Rate Base is used to establish the utility's allowable rate of return (i.e., return on debt and return on equity). For EKPC, whose margin requirements have traditionally been set by the Kentucky PSC on the basis of a times interest earned ratio (TIER) coverage, Rate Base may also be used to classify interest expense and margin requirements.

The classification of EKPC's Rate Base for each of the three alternatives is provided in Schedule 4 of Exhibits A, B or C, respectively. Plant in service and depreciation reserves values are taken from Schedules 1 and 3 of Exhibits A, B or C, respectively. Construction Work in Progress (CWIP) is either direct assigned or allocated on the basis of the labor ratio calculated in Schedule 2 of Exhibits A, B or C, respectively. Prepayments, which primarily relate to insurance, are allocated on the basis of labor. Fuel stocks and materials and supplies (M&S) are either allocated or direct assigned depending upon their nature. Finally, cash working capital (CWC) is based on 45 days worth (i.e., 45/365ths) of operating expense in each category as developed in Schedule 5 of Exhibits A, B or C, respectively. The 45-day convention is a traditional proxy for a more detailed and costly lead-lag study.

A summary of the classified Rate Base is as follows:

Table 4.3A
Classification of Rate Base
Case A - Production Plant Classified as 100% Capacity Related

Plant Category	Total	Production Capacity	Production Energy	Steam Service	Transm.	Distribution Substations	Metering
	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Plant in Service	3,083,652	2,406,990	28,350	41,121	444,062	157,720	5,409
Acc. Depr.	(839,989)	(626,373)	(19,244)	(10,826)	(137,599)	(43,611)	(2,336)
Net Plant	2,243,663	1,780,617	9,106	30,295	306,463	114,109	3,073
CWIP	382,843	198,372	145,871	1,577	29,852	7,039	132
RWIP	(2,705)	(1,429)	(7)	-	(1,450)	181	-
Prepayments	1,571	1,247	6	21	215	80	2
M&S	40,167	25,596	-	476	10,204	3,778	113
Fuel Stocks	69,904	-	68,200	1,704	-	-	-
CWC	22,988	9,018	8,827	249	4,514	253	127
Total	2,758,431	2,013,421	232,003	34,322	349,798	125,440	3,447

Table 4.3B
Classification of Rate Base
Case B - Production Plant Classified Using the Equivalent Peaker Method

Plant Category	Total	Production Capacity	Production Energy	Steam Service	Transm.	Distribution Substations	Metering
	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Plant in Service	3,083,652	915,623	1,515,416	45,422	444,062	157,720	5,409
Acc. Depr.	(839,989)	(247,355)	(397,169)	(11,919)	(137,599)	(43,611)	(2,336)
Net Plant	2,243,663	668,268	1,118,247	33,503	306,463	114,109	3,073
CWIP	382,843	198,370	145,873	1,577	29,852	7,039	132
RWIP	(2,705)	(1,429)	(7)	-	(1,450)	181	-
Prepayments	1,571	468	783	23	215	80	2
M&S	40,168	7,950	17,596	527	10,204	3,778	113
Fuel Stocks	69,904	-	68,200	1,704	-	-	-
CWC	22,989	8,990	8,856	249	4,514	253	127
Total	2,758,433	882,617	1,359,548	37,583	349,798	125,440	3,447

Table 4.3C
Classification of Rate Base
Case C - Production Plant Classified Using the AED Method

Plant Category	Total	Production Capacity	Production Energy	Steam Service	Transm.	Distribution Substations	Metering
	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Plant in Service	3,083,653	1,139,663	1,292,024	44,775	444,062	157,720	5,409
Acc. Depr.	(839,990)	(304,293)	(340,396)	(11,755)	(137,599)	(43,611)	(2,336)
Net Plant	2,243,663	835,370	951,628	33,020	306,463	114,109	3,073
CWIP	382,843	198,370	145,873	1,577	29,852	7,039	132
RWIP	(2,705)	(1,429)	(7)	-	(1,450)	181	-
Prepayments	1,572	585	667	23	215	80	2
M&S	40,167	10,601	14,952	519	10,204	3,778	113
Fuel Stocks	69,904	-	68,200	1,704	-	-	-
CWC	22,988	8,994	8,851	249	4,514	253	127
Total	2,758,432	1,052,491	1,190,164	37,092	349,798	125,440	3,447

4.5.5 Classification of Revenue Requirements

The classification of revenue requirements is developed in Schedule 5 of Exhibits A, B and C, respectively.

- Production -

Production fuel expense is considered to be energy related and, thus, is assigned to that category. The classification of non-fuel production O&M expense is more complicated as some costs could be considered fixed (i.e., capacity related), while other costs are clearly variable (i.e., energy related). Both FERC and NARUC have adopted standard approaches for classifying non-fuel production O&M expense. While the methodologies differ in terms of details, we have found that, in many instances, the two methods produce comparable results. For convenience, we have used the FERC method for classifying non-fuel O&M expenses.

Under FERC's standard methodology, each sub-account in the production O&M category is assigned to either capacity or energy. For example, FERC considers Acct. No. 502 - Steam Operations to be capacity related, while Acct. No. 512 - Maintenance of Boiler Plant is considered to be energy related.

Purchased power expense was generally classified in accordance with the way each component is billed (e.g., demand charges were considered capacity related, while energy charges were considered energy related). The exception to this general rule is that reservation fees were assigned to the energy component as they are related to reserving a source of energy, not providing capacity. In the instant case, we determine that all of EKPC's purchased power expense in 2009 was energy related.

- Transmission -

Transmission related expenses were, for the most part, allocated on the same basis as the corresponding plant investment. Acct. 531, however, was determined to include metering expense, which was assigned to the Metering category, with the remainder assigned to Transmission. In a few instances, direct assignments were made primarily in the Load Control category. In addition, wheeling charges (Acct. 565 - Transmission by Others) from other entities were assigned to the Transmission category.

- Distribution -

Distribution O&M expenses were assigned to the Distribution Substation category.

- Consumer Accounts, Information and Service and Sales -

These expenses are primarily related to the marketing of energy and, therefore, were assigned to the Production - Energy category.

- Administrative and General -

Like general plant, administration and general (A&G) expenses were allocated based on the labor ratio developed in Schedule 2 of Exhibits A, B or C, respectively. This is consistent with FERC's standard methodology. The one exception to this general rule was that property insurance was classified in accordance with net plant.

- Depreciation -

Depreciation expense was assigned on the basis of the corresponding plant investment.

- Taxes -

In accordance with standard RUS accounting practice, property taxes were allocated to individual O&M expense accounts and, except for a very minimal amount, not addressed separately.

- Short Term Interest and Other Deductions -

Short term interest and other deductions are generally relatively minor expense items. In the instant case, however, there was over $7,000,000 of this miscellaneous expense in the Pro Forma Test Year. This expense was classified using various allocation factors that generally reflect the nature of the expense.

- Return Requirements -

Return requirements consist of long term interest expense and margin requirements. Traditionally, for an IOU, the amount of required return is determined by multiplying rate base by an allowable rate of return determined ultimately by the regulatory authority having jurisdiction in the case. While EKPC's margin requirements are not set on the basis of an allowable return on rate base, but rather on the basis of a TIER requirement, we believe that functionalizing/classifying both interest and margin on the basis of rate base is still appropriate.

- Revenue Credits -

Third party revenue and other income credits were classified based on the nature of the revenue. These revenue credits include such things as:

- Sales to third parties (i.e., non-Members);
- Interest income;
- Allowance for funds used during construction (AFUDC);
- Salt River Generation credit; and
- Miscellaneous.

- Summary -

A summary of the functionalized/classified revenue requirements provided in Schedule 5 of Exhibit A, B or C, respectively, is provided in the following tables:

Table 4.4A
Classification of Revenue Requirements
Case A - Production Plant Classified as 100% Capacity Related

Plant Category	Total	Production Capacity	Production Energy	Steam Service	Transm.	Distribution Substations	Metering
	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Prod. O&M	497,150	59,656	426,354	8,871	2,148	22	99
Trans. O&M	29,844	347	-	-	28,977	-	520
Dist. O&M	1,676	-	-	-	-	1,550	126
Cust. Accounts	-	-	-	-	-	-	-
Cust. Service	1,996	-	1,996	-	-	-	-
Sales	6	-	6	-	-	-	-
Admin. & Gen.	29,589	12,139	11,385	356	4,988	453	268
Subtotal Oper.	560,261	72,142	439,741	9,227	36,113	2,025	1,013
Depreciation	63,780	50,125	1,563	856	6,210	4,929	97
Taxes	-	-	-				
Misc. Oper. Exp.	7,244	1,334	5,339	149	339	72	11
Subtotal Exp.	631,285	123,601	446,643	10,232	42,662	7,026	1,121
L.T. Interest	113,320	82,714	9,531	1,410	14,370	5,153	142
Margin	45,862	33,476	3,857	571	5,816	2,085	57
Return	159,182	116,190	13,388	1,981	20,186	7,238	199
Gross Rev. Req.	790,467	239,791	460,031	12,213	62,848	14,264	1,320
Less: Rev. Credits	32,560	12,724	15,399	353	3,665	408	11
Memb. Rev. Req.	757,907	227,067	444,632	11,860	59,183	13,856	1,309

Table 4.4B
Classification of Revenue Requirements
Case B - Production Plant Classified Using the Equivalent Peaker Method

Plant Category	Total	Production Capacity	Production Energy	Steam Service	Transm.	Distribution Substations	Metering
	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Prod. O&M	497,151	59,447	426,563	8,872	2,148	22	99
Trans. O&M	29,844	347	-	-	28,977	-	520
Dist. O&M	1,676	-	-	-	-	1,550	126
Cust. Accounts	-	-	-	-	-	-	-
Cust. Service	1,996	-	1,996	-	-	-	-
Sales	6	-	6	-	-	-	-
Admin. & Gen.	29,589	12,123	11,401	356	4,988	453	268
Subtotal Oper.	560,262	71,917	439,966	9,228	36,113	2,025	1,013
Depreciation	63,779	20,200	31,401	942	6,210	4,929	97
Taxes	-	-	-	-	-	-	-
Misc. Oper. Exp.	7,243	835	5,836	150	339	72	11
Subtotal Exp.	631,284	92,952	477,203	10,320	42,662	7,026	1,121
L.T. Interest	113,320	36,259	55,852	1,544	14,370	5,153	142
Margin	45,863	14,675	22,604	625	5,816	2,086	57
Return	159,183	50,934	78,456	2,169	20,186	7,239	199
Gross Rev. Req.	790,467	143,886	555,659	12,489	62,848	14,265	1,320
Less: Rev. Credits	32,559	4,623	23,476	376	3,665	408	11
Memb. Rev. Req.	757,908	139,263	532,183	12,113	59,183	13,857	1,309

Table 4.4C
Classification of Revenue Requirements
Case C - Production Plant Classified Using the AED Method

Plant Category	Total	Production Capacity	Production Energy	Steam Service	Transm.	Distribution Substations	Metering
	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Prod. O&M	497,150	59,478	426,531	8,872	2,148	22	99
Trans. O&M	29,844	347	-	-	28,977	-	520
Dist. O&M	1,676	-	-	-	-	1,550	126
Cust. Accounts	-	-	-	-	-	-	-
Cust. Service	1,996	-	1,996	-	-	-	-
Sales	6	-	6	-	-	-	-
Admin. & Gen.	29,589	12,125	11,399	356	4,988	453	268
Subtotal Oper.	560,261	71,950	439,932	9,228	36,113	2,025	1,013
Depreciation	63,780	24,696	26,919	929	6,210	4,929	97
Taxes	-	-	-	-	-	-	-
Misc. Oper. Exp.	7,243	910	5,761	150	339	72	11
Subtotal Exp.	631,284	97,556	472,612	10,307	42,662	7,026	1,121
L.T. Interest	113,320	43,238	48,893	1,524	14,370	5,153	142
Margin	45,863	17,499	19,788	617	5,816	2,086	57
Return	159,183	60,737	68,681	2,141	20,186	7,239	199
Gross Rev. Req.	790,467	158,293	541,293	12,448	62,848	14,265	1,320
Less: Rev. Credits	32,559	5,840	22,263	372	3,665	408	11
Memb. Rev. Req.	757,908	152,453	519,030	12,076	59,183	13,857	1,309

4.5.6 Comparison of Alternative Methodologies

The following table provides a comparison of the results of the three different approaches to classifying production plant:

Table 4.5
East Kentucky Power Cooperative, Inc.
Comparison of Results of Alternative COS Methodologies

	Case	Total	Production		Steam		Dist.	
			Capacity	Energy	Direct	Transm.	Substa.	Metering
		($000)	($000)	($000)	($000)	($000)	($000)	($000)
A	100% Production Assigned to Capacity							
	Member Revenue Requirements	$757,909	$227,068	$444,632	$11,860	$59,182	$13,858	$ 1,310
	Average Rates							
	$/kW/mo		8.44			2.20		
	$/MWh	63.32	18.97	37.15		4.94		
	$/Substation/mo						3,701	350
B	Peaker Method							
	Member Revenue Requirements	$757,909	$139,263	$532,183	$12,113	$59,182	$13,858	$ 1,310
	Average Rates							
	$/kW/mo		5.18			2.20		
	$/MWh	63.32	11.64	44.46		4.94		
	$/Substation/mo						3,701	350
C	Average and Excess Method							
	Member Revenue Requirements	$757,909	$152,454	$519,031	$12,075	$59,182	$13,858	$ 1,310
	Average Rates							
	$/kW/mo		5.67			2.20		
	$/MWh	63.32	12.74	43.36		4.94		
	$/Substation/mo						3,701	350

It should be noted again that the environmental surcharge has been fully allocated and rolled into the above results.

While all three approaches have their supporters, we believe that the EP method is the most appropriate for EKPC to use, as it best reflects the role that energy requirements has played in determining EKPC's mix of generating resources. Consequently, the cost allocation and rate design proposed in the next section is based on the EP method.

4.6 Allocation of Revenue Requirements to Rate Classes

Table 4.6 provides the results of an allocation of revenue requirements to the various rate classes. It should be noted that for purposes of this study, the allocation of capacity revenue requirements was based on a 12 coincidental peak (12CP) demand allocator.

Table 4.6
East Kentucky Power Cooperative, Inc.
Allocation of Revenue Requirements to Rate Classes - Equivalent Peaker Method

Description	Alloc. Factor	Total	Rate B	Rate C	Rate E	Rate G [1]	Pumping Stations	Inland Steam	Gallatin
Revenue									
Demand Charge Revenue		$ 162,572,495	$ 10,633,597	$ 4,039,998	$ 130,023,387	$ 3,665,044	$ 804,097	$ 2,092,098	$ 11,314,274
Energy Charge Revenue		616,391,828	41,284,235	15,269,306	490,704,884	15,016,090	7,899,412	10,021,026	36,196,875
Interruptible Credits [2]		(8,918,101)	(484,110)	-	(24,921)		-		(8,409,070)
Power Factor Penalty Revenue		98,907	-	-	98,907		-		
Metering Revenue		512,892	-	-	511,284	1,608	-		
Substation Revenue		12,265,704	-	-	12,206,520	59,184	-		
Other Revenue		325,119	-	-	119		-		325,000
FCA Factor Revenue		(87,740,326)	(6,850,163)	(2,607,370)	(73,361,993)	(2,672,309)	-	(265,571)	(1,982,920)
Subtotal		$ 695,508,518	$ 44,583,559	$ 16,701,934	$ 560,158,187	$ 16,069,617	$ 8,703,509	$ 11,847,553	$ 37,444,159
Environmental Surcharge Revenue		62,400,512	4,064,364	1,521,660	50,303,358	1,463,447	552,025	1,072,999	3,422,659
Total Revenue		$ 757,909,030	$ 48,647,923	$ 18,223,594	$ 610,461,545	$ 17,533,064	$ 9,255,534	$ 12,920,552	$ 40,866,818

[1] Includes Inland Electric and AGC.
[2] The interruptible credit for Gallatin is estimated as the difference between the base demand charge and the interruptible demand charges times the respective interruptible demands.

Table 4.6 (continued)
East Kentucky Power Cooperative, Inc.
Allocation of Revenue Requirements to Rate Classes - Equivalent Peaker Method

Description	Alloc. Factor	Total	Rate B	Rate C	Rate E	Rate G [1]	Pumping Stations	Inland Steam	Gallatin
Allocation of Revenue Requirements									
Production Capacity									
Interruptible Credit [2]	Direct	$ (8,918,101)	$ (484,110)	$ -	$ (24,921)	$ -	$ -	$ -	$ (8,409,070)
Load Following Charge	Direct	325,000							$ 325,000
Adjusted Revenue Requirements [3]	12CP	147,856,598	7,621,802	2,748,677	125,047,381	2,759,805	-	-	9,678,933
Subtotal Production Capacity		$ 139,263,497	$ 7,137,692	$ 2,748,677	$ 125,022,460	$ 2,759,805	$ -	$ -	$ 1,594,863
Production Energy									
Energy Cost Assigned to Pipelines	Direct	$ 8,451,437	$ -	$ -	$ -	$ -	$ 8,451,437 [5]	$ -	$ -
Adjusted Revenue Requirements	ENG	523,731,782	39,070,378	14,491,862	420,360,795	14,360,780	-	-	35,447,967
Subtotal Production Energy		$ 532,183,219	$ 39,070,378	$ 14,491,862	$ 420,360,795	$ 14,360,780	$ 8,451,437	$ -	$ 35,447,967
Steam Service	Direct	$ 12,112,829	$ -	$ -	$ -	$ -	$ -	$ 12,112,829 [7]	$ -
Transmission		59200564							
Transm. Cost Assigned to Pipelines	Direct	$ 804,097	$ -	$ -	$ -	$ -	$ 804,097 [5]	$ -	$ -
Adjusted Revenue Requirements	12CP	58,378,228	3,009,317	1,085,260	49,372,464	1,089,654	-	-	3,821,533
Subtotal Transmission		$ 59,182,325	$ 3,009,317	$ 1,085,260	$ 49,372,464	$ 1,089,654	$ 804,097	$ -	$ 3,821,533
Distribution Substations	SUB	13,857,522	-	-	13,813,107	44,415	-	-	-
Meters	METER	1,309,641	-	-	1,305,443	4,198	-	-	-
Total Revenue Requirements		$ 757,909,033	$ 49,217,387	$ 18,325,799	$ 609,874,270	$ 18,258,851	$ 9,255,534	$ 12,112,829	$ 40,864,363
Revenue Requirements less Revenue		$ 3	$ 569,464	$ 102,205	$ (587,275)	$ 725,787	$ -	$ (807,723)	$ (2,455)
		0.0%	1.2%	0.6%	-0.1%	4.1%	0.0%	-6.3%	0.0%

[3] Increase the Production Capacity revenue requirements ($139,263,497) by the interruptible credits ($8,918,101).

[4] $36.53/MWh * Energy

[5] Assign the transmission charge per contract directly to the pipelines and treat this as a credit against the transmission revenue requirements recovered from the remaining classes.
Assign the difference between the energy revenue and the average system energy cost to the pipelines and treat as a credit against the energy revenue requirements assigned to the remaining classes.
Estimate the average fuel cost to serve the pipelines as equal to the average fuel cost for the system.

[6] The environmental surcharge is reallocated based on the allocated revenue requirements, with the exception that it is only applied to the off-peak energy charge revenue from the pipelines ($3,805,872).

[7] The COS allocation for Inland Steam is developed specifically for this load in Workpaper WP-4 and directly assigned to the customer.

5.0 Rate Design

5.0 Rate Design

5.1 Rate Design Objectives

In order to evaluate EKPC's rate structure, it is necessary to establish specific objectives that may be used as a standard against which the rate structure may be judged. We believe that the following rate design objectives are appropriate for a G&T cooperative such as EKPC:

1. The rate must be designed in a manner that ensures that the revenue generated will be sufficient to cover EKPC's cost of providing service.
2. The rate structure should provide a reliable and stable revenue stream for EKPC and, correspondingly, a reliable and predictable expense for the Member-Systems.
3. The rate structure should reflect the cost of providing service so that no Member-System receives a subsidy from another system or is required to provide a subsidy to another system.
4. The rate structure should result in a fair and equitable sharing of EKPC's costs by the Member-Systems.
5. The rate structure should be simple and concise to facilitate administration and Member-System understanding.
6. Abrupt departures from historical rate structures and policies should be avoided, and major changes should be tempered and/or phased in as appropriate.
7. The rate structure should promote the efficient use of energy and capacity by providing appropriate price signals, and which will facilitate the implementation of the objectives of EISA.
8. The price signals in the wholesale rate should be translatable into the Member-Systems' retail rates.
9. In as much as possible, the rate structure should be designed to enable the Member-Systems to design competitive retail rates.
10. The rate structure should be acceptable to the Member-Systems.

While each of these objectives is laudable and should be pursued, we have generally found that it is not possible to fully accomplish all of the above objectives in any single rate structure. Compromises based on the judgment of EKPC and its Member-Systems are necessary.

5.2 Energy Independence and Security Act

On December 19, 2007, President Bush signed into law the Energy Independence and Security Act of 2007 (EISA). EISA includes, among other things, a section specifically targeting the electric industry; namely, Title V - Energy Savings in Government and Public Institutions, Subtitle D, Utility Energy Efficiency Programs. This section of EISA modifies Title I of PURPA of 1978, which requires covered electric utilities and/or regulatory bodies to consider a number of "rate design" standards such as cost of service, master metering, time-of-use rates, etc. EISA adds four new standards to be considered.

In the case of regulated electric utilities, such as EKPC and its Member-Systems, the authority for "consideration" of the standards is assigned to the state regulatory body, in this case the Kentucky PSC. The Kentucky PSC opened an administrative proceeding in 2008 to consider these standards; however, no final decision of the standards has been issued by the PSC.

Title I of PURPA sets forth three purposes for implementing the rate design standards including:

1. Conservation of energy supplied by electric utilities;
2. The optimization of the efficiency and use of facilities and resources by electric utilities; and
3. Equitable rates to electric customers.

The final determination of action to take on each EISA rate design standard is to be based on these three purposes or objectives of PURPA. However, the language of EISA can be confusing unless read in conjunction with the original PURPA language. For example, one of the provisions is stated as follows:

> "Each electric utility shall integrate energy efficiency resources into utility, State, and regional plans; and adopt policies establishing cost-effective energy efficiency as a priority resource."

This language makes it appear that electric utilities covered by EISA must ("shall") adopt this standard. Actually, the language of the legislation points back to PURPA Title I which requires covered utilities to "consider" adopting such a standard. There is no requirement that the covered utilities actually adopt such a standard, but instead a covered utility or regulatory body may:

- Accept a standard;
- Reject a standard;
- Modify a standard; or
- Defer implementation of a standard.

The decision, of course, must be based on the evidence on the record for this deliberation, and the rationale for the decision on each standard must be documented in writing.

The four new "rate design" standards to be considered under EISA are:

- The inclusion of the consideration of energy efficiency in the Integrated Resource Planning (IRP) process;
- The adoption of rate design modifications to promote energy efficiency (EE) investments;
- The consideration of smart grid investments in lieu of other system improvements; and
- The provision of energy price and other information to consumers.

Two of the four new standards, the second and fourth, relate to rate design. The second standard requires consideration of a rate design approach which aligns incentives from the perspective of the utility with the delivery and promotion of cost-effective energy efficiency programs and investments. This standard is stated as follows:

> (2) *Rate Design modifications to Promote Energy Efficiency Investments.* (A) IN GENERAL - the rates allowed to be charged by any electric utility shall (I) align utility incentives with the delivery of cost-effective energy efficiency; and (II) promote energy efficiency investments. (B) POLICY OPTIONS - In complying with subparagraph (A), each utility shall consider (I) removing the throughput incentive and other regulatory and management disincentives to energy efficiency; (II) providing utility incentives for the successful management of energy efficiency programs; (III) including the impact on adoption of energy efficiency as one of the goals of retail rate design, recognizing that energy efficiency must be balanced with other objectives; (IV) adopting rate designs that encourage energy efficiency for each customer class; (V) allowing timely recovery of energy efficiency related costs; and (VI) offering home energy audits, offering demand

response programs, publicizing the financial and environmental benefits associated with making home energy efficiency improvements, and educating homeowners about all existing Federal and State incentives, including the availability of low-cost loans, that make energy efficiency improvements more affordable.

This standard requires consideration of a variety of rate design related measures intended to promote energy efficiency, including:

- Removing the throughput incentive and other regulatory and management disincentives to energy efficiency;
- Providing utility incentives for the successful management of energy efficiency programs;
- Including the impact on the adoption of energy efficiency as one of the goals of retail rate design, recognizing that energy efficiency must be balanced with other objectives;
- Adopting rate designs that encourage energy efficiency for each customer class;
- Allowing timely recovery of energy efficiency related costs;

(The sixth measure (i.e., offering home audits, etc.) goes beyond the rate design venue.)

A number of these measures seek to align the utility's self interest with the objective of energy efficiency. The issue being addressed here is the natural tendency of most utilities to seek to sell more energy. For an investor-owned utility, more energy generally equates with higher profits, while cooperatives tend to think of increased sales in terms of spreading their fixed costs over more kilowatt-hours, thereby reducing overall rates. The problem with energy efficiency is that it is often perceived as working against the overall objectives of the utility; and thus, this standard seeks to find a way to align the interests of the utility with the goals of energy efficiency.

One way of accomplishing this is to "decouple" revenue from energy sales; but that is generally easier said than done. For example, one could decrease the energy charge at the margin, which would reduce the revenue loss due to decreased energy sales. However, while that might reduce the disincentive from the utility's perspective, it would also diminish the incentive from the customer's perspective to participate in energy efficiency programs. Another approach that has been tried is to provide a regulatory rate of return incentive which rewards utilities for their success in promoting and achieving energy efficiency objectives. However, this approach is often viewed by non-profit cooperatives as a disincentive as it runs counter to the cooperatives' fundamental objective of keeping rates as low as possible. Another approach would be to develop an automatic adjustment clause, similar in some respects to a traditional fuel cost adjustment (FCA) clause, to track the loss in revenue that accompanies decreasing sales; but this can be very complex and difficult to implement. After discussions with the EKPC's staff, we have concluded that there is little enthusiasm on the part of EKPC and/or its Member-Systems to adopt such an automatic adjustment mechanism.

The fourth measure in the foregoing list seeks to incorporate EE incentives in the design of retail rates. While retail rates are the purview of EKPC's Member-Systems, EKPC's wholesale rates clearly form the base for the design of the Member retail rates. We believe that adopting the EP methodology, which inherently will shift cost recovery from the demand charge to the energy charge (in comparison to a rate design based on assigning 100 percent of production plant investment to the capacity component), goes a long way toward promoting EE without greatly diminishing the Member perceived benefits of direct load control (DLC).

The fourth standard provides 1) that electricity customers should be given direct written or electronic access to information concerning time-based electricity prices at wholesale and retail and their usage on at least a daily basis and 2) that everyone should have access to data concerning the sources of the power provided by the utility, including the greenhouse gas emissions associated with each type of generation. It reads as follows:

> (4) *Smart Grid Information*. (A) INFORMATION. - All electricity purchasers shall be provided direct access, in written or electronic machine-readable form as appropriate, and to the extent practicable, to the following information from their electricity provider: (I) PRICES. - time-based electricity prices in the wholesale electricity market, and time-based electricity prices or rates that are available to the purchasers; (II) USAGE. - Purchasers shall be provided with the number of electricity units, expressed in kwh, purchased by them; (III) INTERVALS AND PROJECTIONS. - Updates of information on prices and usage shall be offered on not less than a daily basis, shall include hourly price and use information, where available, and shall include a day-ahead projection of such price information to the extent available; and (IV) SOURCES. - Purchasers and

other interested persons shall be provided annually with written information on the sources of the power provided by the utility, to the extent it can be determined, by type of generation, including greenhouse gas emissions associated with each type of generation, for intervals during which such information is available on a cost-effective basis. (B) ACCESS. - Purchasers shall be able to access their own information at any time through the Internet and on other means of communication elected by that utility for Smart Grid applications. Other interested persons shall be able to access information not specific to any purchaser through the Internet. Information specific to any purchaser shall be provided solely to that purchaser.

The time-of-use aspect of EKPC's rate structure (Section E) is one way EKPC has historically complied with this objective. In addition, EKPC is in the process of implementing a pilot real time pricing program to evaluate the effectiveness of this rate design approach. This program began on January 1, 2010, and is expected to continue for three years. In addition, as smart grid technology advances, EKPC's Members are expected to upgrade their metering capabilities. This will likely lead to further rate design innovation and more sophisticated information systems to provide price signals that reflect real or near real time information to consumers.

5.3 Present Rate Structure

EKPC offers its Member-Systems the following rate tariffs:

Section A – Available to all Members of EKPC. (No Members are currently taking service under this rate schedule.)

Demand Charge	@	$9.47/kW/month
Energy Charge	@	$.046772/kWh

Section B – Available to all Members of EKPC for service to retail customers willing to contract for a minimum demand of 500 kW and a monthly minimum energy usage of 400 hours per kW of contract demand.

Demand Charge		
Minimum Demand	@	$6.81/kW
Excess of Minimum Demand	@	$9.47/kW
Energy Charge	@	$.046772/kWh

Section C – Available to all Members of EKPC for service to retail customers willing to contract for a minimum demand of 500 kW and a monthly minimum energy usage of 400 hours per kW of contract demand.

Demand Charge [8]	@	\$6.81/kW
Energy Charge	@	\$.046772/kWh

Section D – Available as a tariff rider for interruptible service in conjunction with service under Sections A, B, C, E and G. Available for ultimate service to consumers with a minimum interruptible load of 250 kW and a maximum interruptible load of 20,000 kW. Monthly demand credit per the following matrix:

	Annual Hours of Interruption		
Notice Minutes	200	300	400
10	\$4.20	\$4.90	\$5.60
60	\$3.50	\$4.20	\$4.90

Section E – Available to all Members of EKPC:[9]

		Option 1	Option 2
Demand Charge	@	\$7.581/kW/month	\$5.71/kW/month
Energy Charge			
On-Peak	@	\$.048908/kWh	\$.056641/kWh
Off-Peak	@	\$048359/kWh	\$048359/kWh

Section G – Special contract rate:

Demand Charge [10]	@	\$6.63/kW/month
Energy Charge	@	\$.04484/kWh

8 Subject to a 12-month ratchet.

9 All but one Member of EKPC is served under Schedule E2. Owen Electric Cooperative is the sole Member served under Schedule E1.

10 Subject to a 12-month ratchet.

Billing demand for Schedule A, B and C is defined as follows:

"The billing demand (kilowatt demand) is based on EKPC's system peak demand (coincident peak) which is the highest average rate at which energy is used during any fifteen minute interval in the below-listed hours for each month and adjusted for power factor as provided herein:

Months	Hours Applicable for Demand Billing -- EST
October through April	7:00 a.m. to 12:00 noon
	5:00 p.m. to 10:00 p.m.
May through September	10:00 a.m. to 10:00 p.m.

Billing demand applicable to this section is equal to the load center's contribution to EKPC's system peak demand minus the actual demands of Section B, Section C and Section E participants coincident with EKPC's system peak demand."

The time periods used for the time-of-use energy charges are defined as follows:

Months	On-Peak Hours-EST	Off-Peak Hours-EST
October through April	7:00 a.m. to 12:00 noon	12:00 noon to 5:00 p.m.
	5:00 p.m. to 10:00 p.m.	10:00 p.m. to 7:00 a.m.
May through September	10:00 a.m. to 10:00 p.m.	10:00 p.m. to 10:00 a.m.

In addition to the basic demand and energy charges, service to the Member-Systems includes the following delivery and adjustment charges:

1. Metering Point Charge @ $137.00/month
2. Substation Charge

Substation Capacity	Rate
1,000 – 2,999 kVA	$1,033.00/month
3,000 – 7,499 kVA	$2,598.00/month
7,500 – 14,999 kVA	$3,125.00/month
15,000 and over kVA	$5,041.00/month

3. Fuel Cost Adjustment Charge

"The fuel clause shall provide for periodic adjustment per kWh of sales when the unit cost of fuel [F(m) / S(m)] is above or below the base unit cost of $.03653 per kWh [F(b) / S(b)]. The current monthly charges shall be increased or decreased by the product of the kWh furnished during the current month and the fuel adjustment rate for the preceding month where the fuel adjustment rate is defined below:

$$\text{Fuel Adjustment Rate} = \frac{F\,(m)}{S\,(m)} - \frac{F\,(b)}{S\,(b)}$$

Where F is the expense of fossil fuel in the base (b) and current (m) periods; and S is sales in the base (b) and current (m) period. . ."

Finally, EKPC also provides wholesale services to its Members for resale to large C&I customers under individual special contract rates and provisions.

5.4 Proposed Time Periods

5.4.1 Overview

As part of this study, we reviewed EKPC's hourly data to determine whether or not the on- and off-peak periods for both the demand and energy charges were still appropriate. Our review of the demand related time-of-use (TOU) periods was based on an analysis of hourly EKPC system loads over the past three years (2007, 2008 and 2009); and the review of the energy related TOU periods was based on an analysis of hourly system lambdas (i.e., incremental energy costs). While such an analysis is seldom precise or clear cut, we found that the current time period definitions appeared to be reasonably well founded and should be continued.

5.4.2 Demand TOU Periods

The relevant metric for evaluating the time period definitions applicable to monthly billing demand is hourly system loads, since demand charges are generally intended to recover capacity related costs, and capacity requirements are driven by coincidental demand. The first question to be addressed is whether or not the time periods used to define the billing demand windows during the winter and summer season continue to be appropriate. The following two graphs provide a picture of the average hourly loads for the winter and summer seasons, respectively:

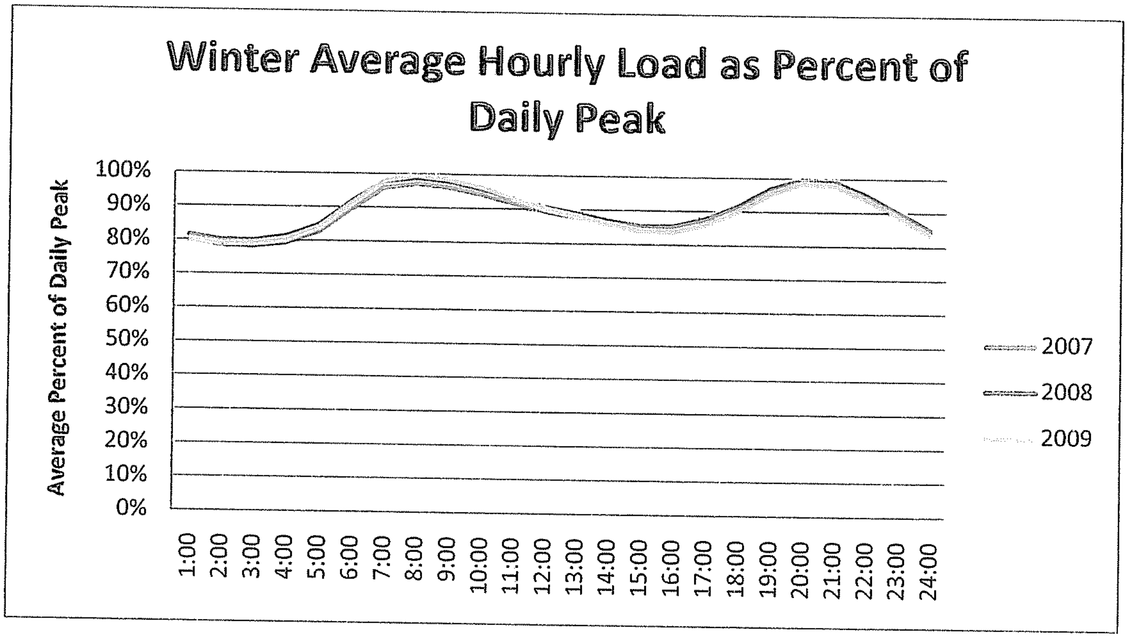

Figure 5.1

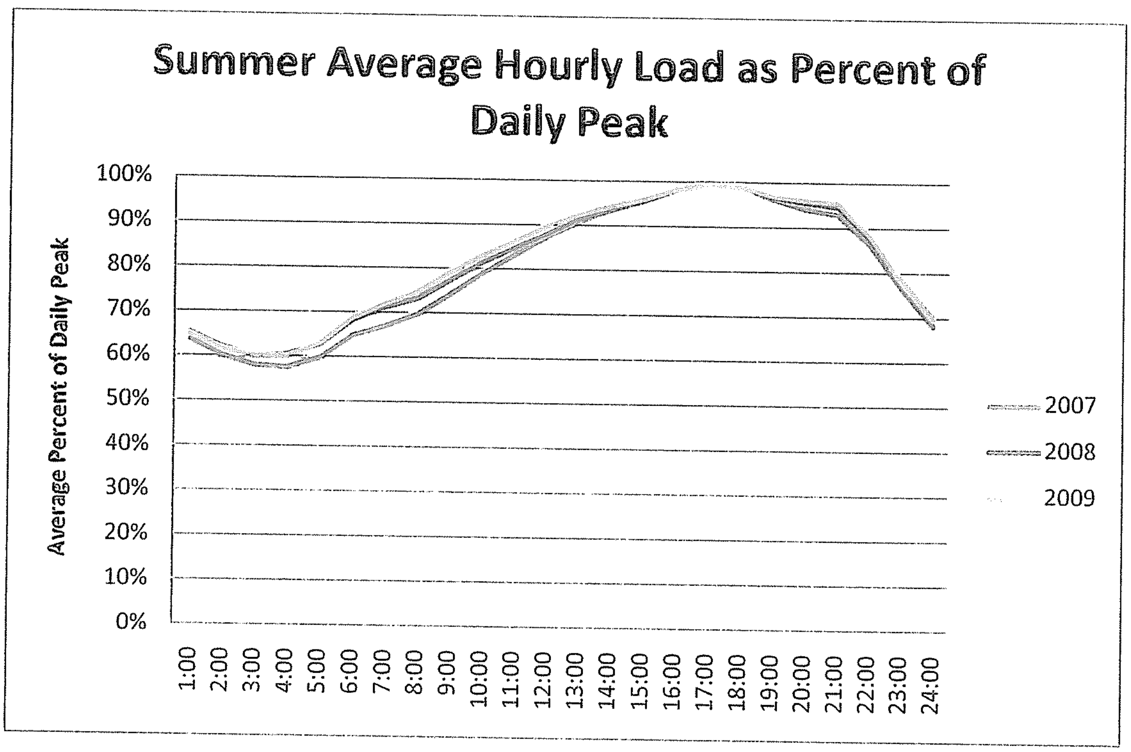

Figure 5.2

As shown, for the winter season, the hourly load typically exceeds 90 percent of the daily peak during the periods 5:00 AM (hour ending 6:00 AM) to 12:00 PM, and 5:00 PM (hour ending 6 PM) to 11:00 PM. These results correlate very closely with the current time period definition of 7:00AM to 12:00 PM and 5:00 PM to 10:00 PM.

With respect to the summer season, the above graphs shows that the hourly load typically exceeds 90 percent of the daily peak during the period 12:00 PM (hour ending 1:00 PM) to 9:00 PM. Again, this correlates fairly closely with the current billing demand window for the summer season of 10:00 AM to 10:00 PM.

The second question is whether or not it would be appropriate to exclude weekends and holidays from the billing demand window. The following table compares the weekend and holiday peak demands with the peak demands recorded for each month over the same three years:

Table 5.1
East Kentucky Power Cooperative, Inc
Monthly Peak Demand--2007, 2008 and 2009

	2007			2008			2009			3-Year Average		
Month	All Days	Weekend Holidays	%	All Days	Weekend Holidays	%	All Days	Weekends Holidays	%	All Days	Weekend Holidays	%
	(MW)	(MW)		(MW)	(MW)		(MW)	(MW)		(MW)	(MW)	
Jan	2,802	2,640	94%	3,033	2,827	93%	3,149	2,802	89%	2,995	2,756	92%
Feb	2,859	2,529	88%	2,622	2,402	92%	2,807	2,287	81%	2,763	2,406	87%
Mar	2,215	2,106	95%	2,314	2,314	100%	2,652	2,182	82%	2,394	2,201	92%
Apr	2,052	2,052	100%	1,970	1,664	84%	1,814	1,573	87%	1,945	1,763	91%
May	1,846	1,745	95%	1,681	1,681	100%	1,667	1,634	98%	1,731	1,687	97%
Jun	2,041	2,041	100%	2,184	2,116	97%	2,099	2,099	100%	2,108	2,085	99%
Jul	2,176	2,094	96%	2,254	2,123	94%	1,971	1,909	97%	2,134	2,042	96%
Aug	2,487	2,245	90%	2,158	2,136	99%	2,177	2,138	98%	2,274	2,173	96%
Sep	2,150	2,081	97%	2,072	2,072	100%	1,759	1,669	95%	1,994	1,941	97%
Oct	1,882	1,882	100%	1,825	1,490	82%	1,900	1,693	89%	1,869	1,688	90%
Nov	2,183	1,985	91%	2,404	2,404	100%	1,864	1,742	93%	2,150	2,044	95%
Dec	2,369	2,294	97%	2,842	2,728	96%	2,564	2,309	90%	2,592	2,444	94%
Annual	2,859	2,640	92%	3,033	2,827	93%	3,149	2,802	89%	2,995	2,756	92%
Average	2,255	2,141	95%	2,280	2,163	95%	2,202	2,003	91%	2,246	2,102	94%

As shown, in virtually all months the peak demand recorded on weekends and/or holidays exceeds 90 percent of the peak demand recorded for the month; and, in fact, over 20 percent of the time the peak for the month is actually set on a weekend and/or holiday. As a result of this analysis, we find little support for changing the billing demand window definition.

5.4.3 Energy TOU Periods

With respect to the time-of-use definitions used for the energy component, hourly system lambdas are the important metric. Again, we looked at the hourly data over the three-year period (2007, 2008 and 2009). The following graphs present summaries of the average hourly system lambdas expressed as a percent of the daily peaks:

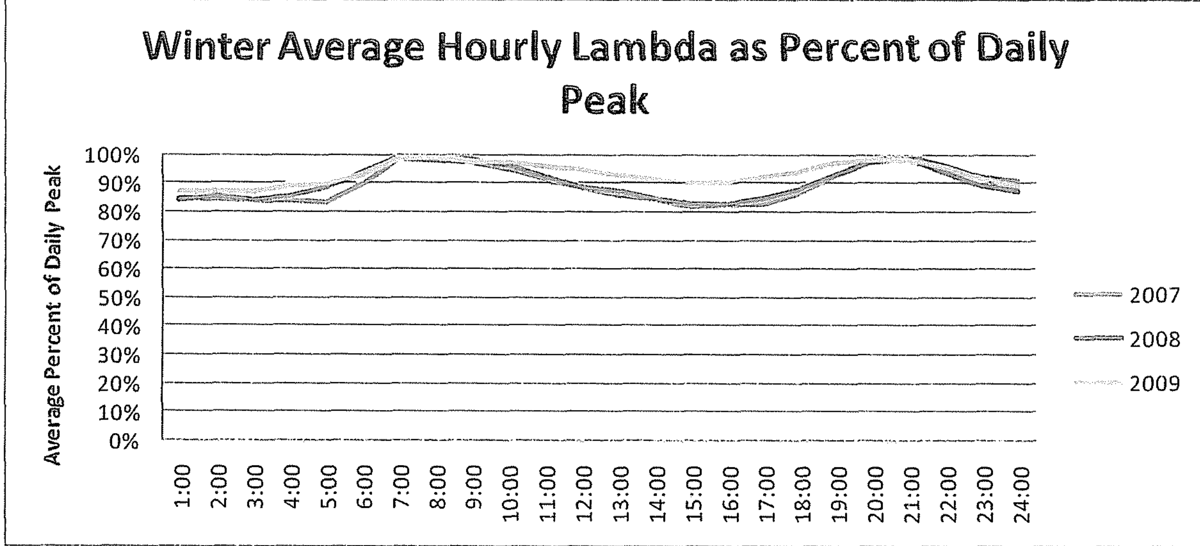

Figure 5.3

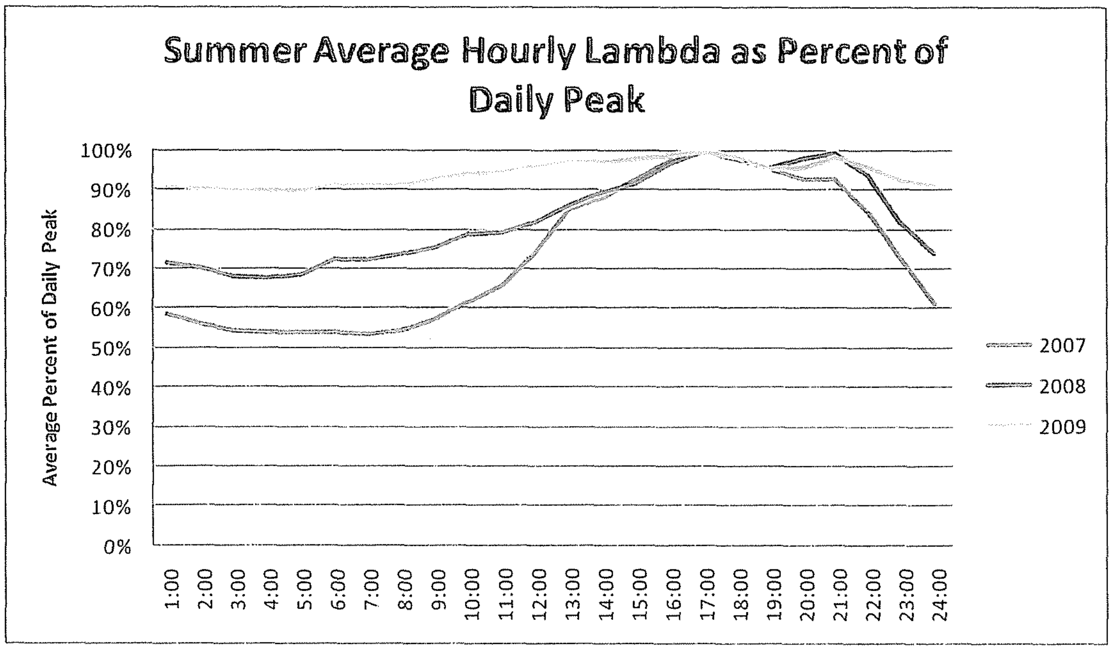

Figure 5.4

As shown, for the winter season, the average hourly system lambda is above 90 percent of the daily peak 5:00 AM (hour ending 6:00 AM) to 12:00 PM, and 4:00 PM (hour ending 5:00 PM) to 11:00 PM, although the system lambda curve is much flatter for 2009; and the curves are not nearly as well defined as for the load profile. For the summer season, the average hourly system lambda is above 90 percent of the daily peak roughly for the period 1:00 PM (hour ending 2:00 PM) to 10:00 PM, although again the profile is much flatter for 2009. This too correlates closely with the current on-peak definition for the summer of 10:00 AM to 10:00 PM.

Again, we looked at the possibility of dropping the weekends and holidays from the on-peak definition. The following table shows the results of that analysis:

Table 5.2 East Kentucky Power Cooperative, Inc. Average Hourly System Lambda												
Description	Average			2007			2008			2009		
Weekends & Holidays as % of Weekdays												
Annual On Peak	90%			88%			90%			93%		
Winter On Peak	91%			92%			87%			92%		
Summer On Peak	90%			81%			93%			95%		
Description	On-Peak	Off-Peak	All Hours	On-Peak	Off-Peak	All Hours	On-Peak	Off-Peak	All Hours	On-Peak	Off-Peak	All Hours
Weekdays Average ($/MWh)												
Annual	31.67	25.08	28.19	35.26	24.91	29.88	33.03	25.85	29.21	26.71	24.49	25.48
Winter	30.51	26.74	28.31	30.54	26.31	28.07	32.39	27.72	29.67	28.59	26.18	27.18
Summer	33.30	22.77	28.03	41.87	22.96	32.41	33.93	23.22	28.57	24.08	22.13	23.11
Weekends and Holidays Average ($/MWh)												
Annual	28.00	23.81	25.82	30.35	23.69	26.89	28.91	24.05	26.42	24.74	23.69	24.15
Winter	27.18	25.47	26.18	27.95	25.22	26.36	27.53	26.40	26.87	26.06	24.80	25.33
Summer	29.15	21.48	25.32	33.72	21.56	27.64	30.85	20.76	25.80	22.89	22.14	22.51
All days Average ($/MWh)												
Annual	30.58	24.71	27.49	33.79	24.54	28.98	31.82	25.32	28.39	26.14	24.27	25.10
Winter	29.52	26.37	27.68	29.72	25.96	27.53	30.99	27.37	28.88	27.85	25.78	26.64
Summer	32.06	22.38	27.22	39.48	22.55	31.02	32.97	22.44	27.71	23.73	22.15	22.94

The above table demonstrates that the hourly system lambda, on average, does not drop significantly on weekends and holidays. As a result of our analysis, we again have concluded that there does not appear to be any serious justification for reducing the on-peak time periods or to exclude weekends and holidays.

5.5 Proposed Rate Design

Proposed rates have been designed to recover the revenue requirements allocated to each class.

Substation and Metering Charge. The substation and metering monthly charges have been adjusted to reflect the COS results as follows:

	Present [11]	Proposed
Metering Charge	$149.29	$350.00
Substation Charge		
1,000 to 2,999 kVA	$1,126	$1,166
3,000 to 7,499 kVA	$2,831	$2,932
7,500 to 14,999 kVA	$3,405	$3,527
15,000 & above	$5,493	$5,690

[11] Includes the environmental surcharge and average 2009 FCA, as adjusted, rolled in.

In addition, we suggest that EKPC consider two changes in the structure of these charges. First, there does not appear to be a clear reason to have two separate charges: substation and metering. Consequently, we suggest that EKPC consider combining the two charges. Second, we suggest that EKPC consider changing the structure of the substation charge to include a base amount and a variable amount based on the highest non coincidental peak (NCP) demand recorded at each substation over the past 12 months. This will recognize the increased cost inherently associated with greater transformer capacity, while taking away any perverse price incentives for Members to oppose EKPC's decisions regarding the upgrade or transfer of substation transformers.

Environmental Surcharge. At the present time, environmental costs are recovered through a surcharge that is applied as a percent of revenue. We recommend that EKPC roll in the current amount, redistributing it based on the results of the COS analysis. This will enable EKPC to recover its costs on a more fair and equitable basis, while allowing the stated rates to more accurately reflect the actual charges. A base environmental charge and automatic adjustment mechanism should then be established to track changes in cost from the based amount rolled into the base rates.

Section B. The proposed Section B rate is designed to track the COS results and is presented below:

		Present[11]	Proposed
Demand Charge			
Base	@	$ 7.43/kW	$ 7.25/kW
Excess	@	$10.33/kW	$10.15/kW
Energy Charge	@	$0.04255/kWh	$0.04349/kWh

Section C. The proposed Section C rate is designed to track the COS results and is presented below:

		Present[11]	Proposed
Demand Charge	@	$7.43/kW	$7.10/kW
Energy Charge	@	$0.04232/kWh	$0.04325/kWh

Section E. At the present time, EKPC's Section E rate, which is used to serve the majority of the Member-Systems' requirements, consists of two options. However, only one Member-System is served under Option 1; and we recommend that the two options be combined. The proposed Section E rate presented below is designed to track the COS results.

		Present[11]	Proposed
Demand Charge	@	$6.22/kW	$7.38/kW
Energy Charge			
On-Peak	@	$0.05324/kWh	$0.04877/kWh
Off-Peak	@	$0.04421/kWh	$0.04277/kWh

Note that the proposed on-peak/off-peak rate differential of $0.006/kWh has been based on an analysis of the corresponding average differential of system lambda (i.e., hourly incremental energy cost) over the past three years.

Section G. The proposed Section G rate is designed to track the COS results and is presented below:

		Present[11]	Proposed
Demand Charge	@	$7.24/kW	$7.38/kW
Energy Charge	@	$0.04024/kWh	$0.04217/kWh

5.6 Comparison of Present and Proposed Rates

A comparison of the present and proposed rates is presented in the following table:

Table 5.3
East Kentucky Power Cooperative, Inc.
Comparison of Present and Proposed Rates (Average Adjusted FCA for 2009)

Rate Component	Units	Average COS	B Present	B Proposed	C Present	C Proposed	E1 Present	E1 Proposed	E2 Present	E2 Proposed	G Present	G Proposed
Demand Charge												
Base Demand Tariff Charge	$/kW/mo		6.81	7.25								
Environmental Surcharge	$/kW/mo		0.62									
Adjusted Average	$/kW/mo		7.43	7.25								
Excess Demand Tariff Charg	$/kW/mo		9.47	10.15								
Environmental Surcharge	$/kW/mo		0.86									
Adjusted Average	$/kW/mo		10.33	10.15								
Tariff Charge or Avg. Charge	$/kW/mo		6.91	7.35	6.81	7.10	7.58	7.38	5.71	7.38	6.63	7.38
Environmental Surcharge	$/kW/mo		0.63		0.62		0.68		0.51		0.61	
Adjusted Average	$/kW/mo	7.38	7.54	7.35	7.43	7.10	8.26	7.38	6.22	7.38	7.24	7.38
Energy Charge												
On-Peak Tariff Charge	$/kWh						0.04891	0.05655	0.05664	0.05655		
Average Adjusted FCA	$/kWh						(0.00787)	(0.00787)	(0.00779)	(0.00779)		
Tariff plus Average FCA	$/kWh						0.04104	0.04869	0.04885	0.04877		
Environmental Surcharge	$/kWh						0.00370		0.00438			
Adjusted Avg. On-Peak	$/kWh						0.04475	0.04869	0.05324	0.04877		
Off-Peak Tariff Charge	$/kWh						0.04836	0.05055	0.04836	0.05055		
Average Adjusted FCA	$/kWh						(0.00787)	(0.00787)	(0.00779)	(0.00779)		
Tariff plus Average FCA	$/kWh						0.04049	0.04269	0.04057	0.04277		
Environmental Surcharge	$/kWh						0.00365		0.00364			
Adjusted Avg. Off-Peak	$/kWh						0.04415	0.04269	0.04421	0.04277		
Tariff Charge or Avg. Charge	$/kWh		0.04677	0.05126	0.04677	0.05124	0.04864	0.05360	0.05255	0.05360	0.04484	0.05015
Average Adjusted FCA	$/kWh		(0.00777)	(0.00777)	(0.00799)	(0.00799)	(0.00787)	(0.00787)	(0.00779)	(0.00779)	(0.00798)	(0.00798)
Tariff plus Average FCA	$/kWh		0.03900	0.04349	0.03879	0.04325	0.04078	0.04573	0.04477	0.04581	0.03686	0.04217
Environmental Surcharge	$/kWh		0.00355		0.00353		0.00368		0.00402		0.00338	
Adjusted Average	$/kWh	0.04446	0.04255	0.04349	0.04232	0.04325	0.04446	0.04573	0.04878	0.04581	0.04024	0.04217

Table 5.3 (continued)
Comparison of Present Rate Tariff Provisions
Comparison of Present and Proposed Rates (Average Adjusted FCA for 2009)

Rate Component	Units	COS	Present As Stated	Present w/ ES @8.97%	Proposed
Metering Charge	$/mo	350.00		149.29	350.00
Substation Charge ($/mo)					
1,000 to 2,999 kVA	$/mo		1,033	1,126	1,166
3,000 to 7,4999 kVA	$/mo		2,598	2,831	2,932
7,500 to 14,999 kVA	$/mo		3,125	3,405	3,527
15,000 kVA and over	$/mo		5,041	5,493	5,690
Average	$/mo	3701.00	3,271	3,564	3,692

5.7 Comparison of Revenue From Member-Systems

A comparison of the revenue under the present and proposed rates from each of the Member-Systems is presented in the following tables:

- Table 5.4 – Schedule B
- Table 5.5 – Schedule C
- Table 5.6 – Schedule E
- Table 5.7 – Schedule G
- Table 5.8 – Special Contracts
- Table 5.9 – Total

Table 5.4
East Kentucky Power Cooperative, Inc.
Comparison of Present and Proposed Revenue - Schedule B

Member System	Present	Proposed	Increase (Decrease)	
			Amount	Percent
	($)	($)	($)	(%)
Big Sandy			-	
Blue Grass	11,631,640	11,765,913	134,273	1.2%
Clark	-		-	
Cumberland Valley	-		-	
Farmers	-		-	
Fleming Mason	-		-	
Grayson	83,102	85,037	1,935	2.3%
Inter-County	2,798,095	2,830,425	32,330	1.2%
Jackson	2,603,250	2,632,411	29,161	1.1%
Licking Valley	-		-	
Nolin	2,576,504	2,606,619	30,115	1.2%
Owen	9,697,742	9,849,430	151,688	1.6%
Salt River	5,555,872	5,619,815	63,943	1.2%
Shelby	8,969,498	9,066,103	96,605	1.1%
So Ky	3,931,692	3,969,408	37,715	1.0%
Taylor	800,529	810,478	9,949	1.2%
Total	48,647,923	49,235,638	587,715	1.2%

Table 5.5
East Kentucky Power Cooperative, Inc.
Comparison of Present and Proposed Revenue - Schedule C

Member System	Present	Proposed	Increase (Decrease) Amount	Increase (Decrease) Percent
	($)	($)	($)	(%)
Big Sandy	-		-	
Blue Grass	-		-	
Clark	-		-	
Cumberland Valley	-		-	
Farmers	2,153,024	2,163,687	10,662	0.5%
Fleming Mason	9,334,490	9,398,592	64,102	0.7%
Grayson	987,529	992,148	4,619	0.5%
Inter-County	-	-	-	
Jackson	1,225,099	1,231,153	6,054	0.5%
Licking Valley	-		-	
Nolin	-		-	
Owen	-		-	
Salt River	-		-	
Shelby	-		-	
So Ky	3,376,282	3,390,540	14,258	0.4%
Taylor	1,147,170	1,156,491	9,321	0.8%
Total	18,223,595	18,332,611	109,016	0.6%

Table 5.6
East Kentucky Power Cooperative, Inc.
Comparison of Present and Proposed Revenue - Schedule E

Total $ Rate E	Present	Proposed	Increase (Decrease) Amount	Increase (Decrease) Percent
	($)	($)	($)	(%)
Big Sandy	17,343,169	17,309,461	(33,708)	-0.2%
Blue Grass	67,071,756	67,042,586	(29,170)	0.0%
Clark	29,033,852	29,019,470	(14,382)	0.0%
Cumberland Valley	34,028,590	33,913,789	(114,802)	-0.3%
Farmers	29,211,536	29,059,142	(152,393)	-0.5%
Fleming Mason	27,684,130	27,599,798	(84,331)	-0.3%
Grayson	16,743,795	16,723,286	(20,509)	-0.1%
Inter-County	26,416,110	26,413,937	(2,173)	0.0%
Jackson	59,063,662	59,012,529	(51,133)	-0.1%
Licking Valley	17,826,624	17,786,024	(40,600)	-0.2%
Nolin	38,342,568	38,271,686	(70,881)	-0.2%
Owen	63,889,647	63,376,078	(513,570)	-0.8%
Salt River	60,458,739	60,187,775	(270,965)	-0.4%
Shelby	18,816,825	18,798,447	(18,378)	-0.1%
So Ky	76,357,497	76,364,292	6,795	0.0%
Taylor	28,173,047	28,116,998	(56,049)	-0.2%
Total	610,461,546	608,995,298	(1,466,248)	-0.2%
Green Power Premium	114,934	114,934		
Total E Incl Gr Power	610,576,480	609,110,232	(1,466,248)	-0.2%

Table 5.7 East Kentucky Power Cooperative, Inc. Comparison of Present and Proposed Revenue - Schedule G				
Member System	Present	Proposed	Increase (Decrease) Amount	Increase (Decrease) Percent
	($)	($)	($)	(%)
Big Sandy	-		-	
Blue Grass	-		-	
Clark	-		-	
Cumberland Valley	-		-	
Farmers	-		-	
Fleming Mason	12,517,200	13,045,766	528,566	4.2%
Grayson	-		-	
Inter-County	-		-	
Jackson	-		-	
Licking Valley	-		-	
Nolin	5,015,865	5,219,859	203,994	4.1%
Owen	-		-	
Salt River	-		-	
Shelby	-		-	
So Ky	-		-	
Taylor	-		-	
Total	17,533,064	18,265,625	732,560	4.2%

Table 5.8
East Kentucky Power Cooperative, Inc.
Comparison of Present and Proposed Revenue - Special Contracts

Member System	Present	Proposed	Increase (Decrease) Amount	Increase (Decrease) Percent
	($)	($)	($)	(%)
Big Sandy	-		-	
Blue Grass	-		-	
Clark	-		-	
Cumberland Valley	-		-	
Farmers	-		-	
Fleming Mason	18,348,004	18,357,166	9,163	0.0%
Grayson	-		-	
Inter-County	-		-	
Jackson	-		-	
Licking Valley	-		-	
Nolin	-		-	
Owen	40,866,819	40,887,617	20,798	0.1%
Salt River	-		-	
Shelby	-		-	
So Ky	-		-	
Taylor	3,828,082	3,829,664	1,582	0.0%
Total	63,042,905	63,074,447	31,543	0.1%

Table 5.9
East Kentucky Power Cooperative, Inc.
Comparison of Present and Proposed Revenue - Total

Member System	Present	Proposed	Increase (Decrease) Amount	Increase (Decrease) Percent
	($)	($)	($)	(%)
Big Sandy	17,343,169	17,309,461	(33,708)	-0.2%
Blue Grass	78,703,396	78,808,499	105,103	0.1%
Clark	29,033,852	29,019,470	(14,382)	0.0%
Cumberland Valley	34,028,590	33,913,789	(114,802)	-0.3%
Farmers	31,364,560	31,222,829	(141,731)	-0.5%
Fleming Mason	67,883,823	68,401,322	517,499	0.8%
Grayson	17,814,425	17,800,470	(13,955)	-0.1%
Inter-County	29,214,205	29,244,362	30,157	0.1%
Jackson	62,892,010	62,876,093	(15,918)	0.0%
Licking Valley	17,826,624	17,786,024	(40,600)	-0.2%
Nolin	45,934,936	46,098,164	163,228	0.4%
Owen	114,454,208	114,113,125	(341,084)	-0.3%
Salt River	66,014,611	65,807,589	(207,022)	-0.3%
Shelby	27,786,323	27,864,550	78,227	0.3%
So Ky	83,665,472	83,724,240	58,769	0.1%
Taylor	33,948,828	33,913,631	(35,197)	-0.1%
Total	757,909,033	757,903,618	(5,415)	0.0%
Green Power Premium	114,934	114,934		
Total Incl Green Power	758,023,967	758,018,552	(5,415)	0.0%

100% Capacity Method

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Plant in Service
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total as of 12/31/09 [1] ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		**Intangible Plant**									
3	301	Organization	LABOR	5,040	2,068	1,939	61	850	77	46	
4	302	Franchises	LABOR		-	-	-	-	-	-	
5	303	Misc. Intang. Plant	TRANS	1,815,946				1,815,946			2
6		Subtotal - Intangible Plant		1,820,987	2,068	1,939	61	1,816,796	77	46	Sum(L3 : L5)
7											
8		**Production Plant**									
9		Steam									
10	310	Land & Land Rights	3	9,135,877	8,890,847	-	245,030				
11	311	Struct. & Improve.	3	236,593,520	232,416,443	-	4,177,077				
12	312	Boiler Plant Equip.	3	1,508,357,416	1,472,790,569	-	35,566,847				
13	313	Engines & Gen.	3	-	-	-	-				
14	314	Turbogenerator Units	3	266,919,252	266,919,252	-	-				
15	315	Access. Elec. Equip.	3	90,036,611	89,942,968	-	93,643				
16	316	Misc. Plant Equipment	3	6,290,109	6,137,833	-	152,276				
17		Subtotal		2,117,332,785	2,077,097,912	-	40,234,873	-	-	-	Sum(L10 : L16)
18		Nuclear									
19	320	Land & Land Rights									
20	321	Struct. & Improve.									
21	322	Reactor Plant Equip.									
22	323	Turbogenerator Units									
23	324	Access. Elec. Equip.									
24	325	Misc. Plant Equipment									
25		Subtotal		-	-	-	-	-	-	-	Sum(L19 : L24)
26		Hydraulic									
27	330	Land & Land Rights									
28	331	Struct. & Improve.									
29	332	Rsrvr Dams & Strwys									
30	333	Wheels Turb. & Gen.									
31	334	Accessory Electrical Equip.									
32	335	Misc. Plant Equipment									
33	336	Rds RR & Bridges									
34		Subtotal		-	-	-	-	-	-	-	Sum(L27 : L33)
35		Other									
36	340	Land & Land Rights	PROD_OTH_PLNT	4,759,583	4,759,583	-	-	-	-	-	
37	341	Struct. & Improve.	PROD_OTH_PLNT	34,148,434	34,148,434	-	-	-	-	-	
38	342	Prod. & Access.	PROD_OTH_PLNT	14,370,188	14,370,188	-	-	-	-	-	
39	343	Prime Movers	PROD_OTH_PLNT	155,318,256	155,318,256	-	-	-	-	-	
40	344	Generators	PROD_OTH_PLNT	51,952,739	51,952,739	-	-	-	-	-	
41	345	Access. Elec. Equip.	PROD_OTH_PLNT	18,773,076	18,773,076	-	-	-	-	-	
42	346	Misc. Plant Equip.	PROD_OTH_PLNT	5,910,707	5,910,707	-	-	-	-	-	
43		Subtotal		285,232,982	285,232,982	-	-	-	-	-	Sum(L36 : L42)
44		Subtotal--Production		2,402,565,767	2,362,330,894	-	40,234,873	-	-	-	L17 + L43

[1] Includes Acct. 106, Plant Completed Not Yet Classified. See Workpaper WP-6. Also, includes plant investment recovered through the Environmental Surcharge.
[2] Intangible plant related to interconnections with other utilities. See Workpaper WP-21.
[3] Investment in Steam Plant facilities has been assigned first directly to Inland Steam, (see Workpaper WP-4), with the remainder allocated using PROD_PEAKER

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Plant in Service
Calendar 2009
(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total as of 12/31/09 [1] ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
45											
46		**Transmission**									
47	350	Land & Land Rights	TRANS_PLNT	46,938,315				46,938,315			
48	352	Struct. & Improve.	TRANS_PLNT					-			
49	353	Station Equip.	[4]	174,395,774	14,429,684			155,224,110		4,741,980	[5]
50	354	Towers & Fixtures	TRANS_PLNT	3,905,020				3,905,020			
51	355	Poles & Fixtures	TRANS_PLNT	130,834,247				130,834,247			
52	356	OH Cond. & Devices	TRANS_PLNT	92,899,082				92,899,082			
53	357	UG Conduit	TRANS_PLNT					-			
54	358	UG Cond. & Devices	TRANS_PLNT					-			
55	359	Roads & Trails	TRANS_PLNT	23,288				23,288			
56		Subtotal - Transmission		448,995,725	14,429,684	-	-	429,824,061	-	4,741,980	Sum(L47 : L55)
57											
58		**Distribution**									
59	360	Land & Land Rights	DISTSUB_PLANT	7,800,241					7,800,241		
60	361	Struct. & Improve.							-		
61	362	Station Equip.	DISTSUB_PLANT	147,457,361					147,457,361		
62	363	Stor. Battery Equip.							-		
63	364	Poles Tower & Fix.							-		
64	365	OH Cond. & Devices							-		
65	366	UG Conduit							-		
66	367	UG Cond. & Devices							-		
67	368	Line Transformers	DISTSUB_PLANT	1,333,351					1,333,351		
68	369	Services							-		
69	370	Meters							-		
70	371	Install on Cust. Ld							-		
71	372	Leased Ld from Cust.							-		
72	373	Street Light & Signal							-		
73		Subtotal - Distribution		156,590,953	-	-	-	-	156,590,953	-	Sum(L59 · L72)
74											
75		Subtotal - Prod, Trans. Dist Plant		3,008,152,446	2,376,760,578	-	40,234,873	429,824,061	156,590,953	4,741,980	L44 + L56 + L73
76											
77		**General**									
78	389	Land & Land Rights	LABOR	870,935	357,315	335,100	10,470	146,824	13,344	7,881	
79	390	Struct. & Improve.	LABOR	14,725,147	6,041,234	5,665,625	177,018	2,482,402	225,618	133,250	
80	391	Off. Furn. & Equip.	LABOR	6,588,264	2,702,944	2,534,890	79,201	1,110,666	100,945	59,618	
81	392	Transp. Equip.	LABOR	7,270,031	2,982,650	2,797,206	87,396	1,225,600	111,391	65,788	
82	393	Stores Equip.	LABOR	152,406	62,527	58,639	1,832	25,693	2,335	1,379	
83	394	Shop & Garage Equip.	LABOR	1,601,385	656,995	616,147	19,251	269,966	24,536	14,491	
84	395	Lab Equip.	LABOR	2,549,035	1,045,784	980,763	30,643	429,723	39,056	23,067	
85	396	Power Op. Equip.	LABOR	8,677,464	3,560,072	3,338,728	104,316	1,462,869	132,956	78,524	
86	397	Communication Equip.	LABOR	30,027,149	12,319,132	11,553,199	360,970	5,062,052	460,075	271,721	
87	398	Misc. Equip.	LABOR	1,215,623	498,729	467,721	14,614	204,933	18,626	11,000	
88	399	Other Tangible Prop.	LABOR		-	-	-	-	-	-	
89		Subtotal-General Plant		73,677,440	30,227,381	28,348,018	885,710	12,420,729	1,128,884	666,719	Sum(L78 : L88)
90											
91		Grand Total		3,083,650,873	2,406,990,027	28,349,957	41,120,643	444,061,586	157,719,914	5,408,745	L44 + L56 + L89
92											

[4] Distribution meters and Generator step Up Transformers are direct assigned, with the remainder assigned to Transmission. Distribution meters includeds $35,557 in Plant Completed Not Yet Classified.
[5] Distribution meter investment does not include meters installed on portable substations.

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Plant in Service
Calendar 2009
(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total as of 12/31/09 [1]	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
93											
94		**Allocation Factors Based on Plant**									
95	301-303	Intangible Plant		1,820,987	2,068	1,939	61	1,816,796	77	46	L6
96			INTG_PLNT	1.000000	0.001136	0.001065	0.000033	0.997699	0.000042	0.000025	
97											
98	310-316	Production Plant--Steam		2,117,332,785	2,077,097,912	-	40,234,873	-	-	-	L17
99			PROD_STM_PLNT	1.000000	0.980997	-	0.019003	-	-	-	
100											
101			PROD_CAP	1.000000	1.000000	0.000000					
102			PROD_PEAKER	1.000000	0.282600	0.717400	Applies only to production steam plant				
103			PROD_AED	1.000000	0.390561	0.609439	Applies to all production plant				
104											
105	340-346	Production Plant--Other		285,232,982	285,232,982	-	-	-	-	-	L43
106			PROD_OTH_PLNT	1.000000	1.000000	0.000000					
107											
108	301-346	Total Production Plant		2,402,565,767	2,362,330,894	-	40,234,873	-	-	-	L44
109			PROD_PLNT	1.000000	0.983253	0.000000	0.016747	0.000000	0.000000	0.000000	
110											
111	353	Transmission Stations		221,334,089	14,429,684	-	-	202,162,425	-	4,741,980	Sum(L47:L49)
112			TRANS_STA	1.000000	0.065194	0.000000	0.000000	0.913381	0.000000	0.021425	
113											
114	354-358	Transmission Lines		227,638,349	-	-	-	227,638,349	-	-	Sum(L50:L55)
115			TRANS_LINES	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	
116											
117	350-359	Total Transmission Plant		448,995,725	14,429,684	-	-	429,824,061	-	4,741,980	L56
118			TRANS_PLNT	1.000000	0.032138	0.000000	0.000000	0.957301	0.000000	0.010561	
119											
120	360-373	Distribution Plant		156,590,953	-	-	-	-	156,590,953	-	L73
121			DISTSUB_PLNT	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	
122											
123	301-373	Prod, Trans, Dist Plant		3,008,152,446	2,376,760,578	-	40,234,873	429,824,061	156,590,953	4,741,980	L75
124			PTD_PLNT	1.000000	0.790106	0.000000	0.013375	0.142886	0.052056	0.001576	
125											
126	301-399	Total Gross Plant		3,083,650,873	2,406,990,027	28,349,957	41,120,643	444,061,586	157,719,914	5,408,745	L91
127			GROSS_PLNT	1.000000	0.78056503	0.00919363	0.01333505	0.14400514	0.05114714	0.00175401	
128											

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Payroll Expense
Calendar 2009

Note: Labor expense is allocated on the same basis as the corresponding expense.

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		Power Production									
3		Steam									
4	500	Oper. Super. & Eng.		4,634,976	4,566,924	-	68,052	-	-	-	
5	501	Fuel		3,102,961	-	3,022,441	80,519	-	-	-	
6	502	Steam		3,609,377	3,557,853	-	51,524	-	-	-	
7	503	Steam-Other Sources									
8	504	Steam Transferred									
9	505	Electric		2,960,651	2,925,976	-	34,675	-	-	-	
10	506	Misc. Steam Power		1,613,121	1,586,005	-	27,116	-	-	-	
11	507	Rents									
12	510	Main. Super. & Eng.		1,802,051	-	1,773,034	29,017	-	-	-	
13	511	Main. Struct.		439,291	432,348	-	6,943	-	-	-	
14	512	Main. Boiler Plant		6,291,880	-	6,157,836	134,044	-	-	-	
15	513	Main. Electric Plant		1,495,446	-	1,485,977	9,469	-	-	-	
16	514	Main. Misc. Plant		56,422	56,164	-	258	-	-	-	
17											
18		Nuclear									
19	517	Oper. Super. & Eng.									
20	518	Nuclear Fuel									
21	519	Coolants & Water									
22	520	Steam Exp.									
23	521	Steam - Other Sources									
24	522	Steam Transferred									
25	523	Electric									
26	524	Misc. Nuclear Power									
27	525	Rents									
28	528	Main. Super. & Eng.									
29	529	Main. Struct.									
30	530	Main. Reactor Plant									
31	531	Main. Electric Plant									
32	532	Main. Misc. Plant									
33											
34		Hydraulic									
35	535	Oper. Super. & Eng.									
36	536	Water for Power									
37	537	Hydraulic									
38	538	Electric									
39	539	Misc. Hydr. Power									
40	540	Rents									
41	541	Main. Super. & Eng.									
42	542	Main. Struct.									
43	543	Main. Waterways									
44	544	Main. Electric Plant									
45	545	Main. Misc. Hydr. Plant									

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Payroll Expense
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
46											
47		**Power Production (Con't.)**									
48		**Other**									
49	546	Oper. Super. & Eng.		251,711	251,711	-	-	-	-	-	
50	547	Fuel			-	-	-	-	-	-	
51	548	Generation		791,054	791,054	-	-	-	-	-	
52	549	Misc. Other Power		205,497	205,497	-	-	-	-	-	
53	550	Rents									
54	551	Main. Super. & Eng.		16,947	16,947	-	-	-	-	-	
55	552	Main. Struct.		7,368	7,368	-	-	-	-	-	
56	553	Main. Gen. & Elec. Plant		104,586	104,586	-	-	-	-	-	
57	554	Main. Misc. Other Power		1,096	1,096	-	-	-	-	-	
58											
59		**Other Power Supply**									
60	555	Purchased Power (Net)			-	-	-	-	-	-	
61	556	System Control & Dispatch		2,118,102	105,905	741,336	-	1,213,526	-	57,335	
62	557	Other Expenses		716,357	360,801	346,708	564	6,023	2,194	66	
63											
64		Subtotal - Production		30,218,893	14,970,235	13,527,332	442,181	1,219,550	2,194	57,401	Sum(L4 : L62)
65											
66		**Transmission**									
67	560	Oper. Super. & Eng.		1,470,607	35,074	-	-	1,383,072	-	52,461	
68	561	Load Dispatching		1,231,141	-	-	-	1,074,003	-	157,138	
69	562	Oper. Station		781,484	50,948	-	-	713,793	-	16,743	
70	563	Oper. OH Line		456,603	-	-	-	456,603	-	-	
71	564	Oper. UG Line									
72	565	Trans of Electricity - Others			-	-	-	-	-	-	
73	566	Misc. Transmission Oper.		292,615	-	-	-	292,615	-	-	
74	567	Rents			-	-	-	-	-	-	
75	568	Main. Super. & Eng.		7,912	189	-	-	7,441	-	282	
76	569	Main. Struct.									
77	570	Main. Station Equip.		525,038	34,229	-	-	479,560	-	11,249	
78	571	Main. OH Lines		574,270	-	-	-	574,270	-	-	
79	572	Main. UG Lines									
80	573	Main. Misc. Trans. Plant			-	-	-	-	-	-	
81											
82		Subtotal - Transmission		5,339,672	120,440	-	-	4,981,357	-	237,874	Sum(L67 : L80)

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Payroll Expense
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
83											
84		**Distribution**									
85	580	Oper. Super. & Eng.									
86	581	Load Dispatching									
87	582	Station		48,173	-	-	-	-	10,596	37,577	
88	583	OH Line		250,750	-	-	-	-	250,750	-	
89	584	UG Line									
90	585	Street Light & Signal Sys.									
91	586	Meters									
92	587	Customer Installation									
93	588	Misc. Distribution									
94	589	Rents									
95	590	Main. Super. & Eng.									
96	591	Main. Struct.									
97	592	Main. Station Equipment		300,042	-	-	-	-	300,042	-	
98	593	Main. OH Lines									
99	594	Main. UG Lines									
100	595	Main. Line Transf.									
101	596	Main. Street Light & Sig.									
102	597	Main. Meters									
103	598	Main. Misc.									
104											
105		Subtotal - Distribution									
106				598,965	-	-	-	-	561,388	37,577	
107		**Customer Accounts**									
108	901	Supervision									
109	902	Meter Reading									
110	903	Cust. Rec. & Coll.									
111	904	Uncollectible Accts.									
112	905	Misc. Cust. Accts.									
113											
114		Subtotal - Cust. Accts.									
115				-	-	-	-	-	-	-	Sum(L108 : L112)
116		**Customer Service & Info.**									
117	907	Supervision		-							
118	908	Cust. Assistance		613,032	-	613,032		-			
119	909	Advertising		8,519	-	8,519		-			
120	910	Misc. Serv. & Info.		259	-	259		-			
121											
122		Subtotal - Cust. Service		621,810	-	621,810	-	-	-	-	Sum(L107 : L121)

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Payroll Expense
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
123											
124		Sales									
125	911	Supervision									
126	912	Demo. & Selling									
127	913	Advertising		3,283	-	3,283		-			
128	916	Misc. Sales									
129											
130		Subtotal - Sales		3,283	-	3,283	-	-	-	-	Sum(L125 : L128)
131											
132		Summary									
133		Total Labor (Excluding A&G)		36,782,622	15,090,675	14,152,425	442,181	6,200,907	563,582	332,852	L48+L66 + L89 + L98+L106+L130
134											
135		Labor Allocator	LABOR	1.000000	0.410266	0.384758	0.012021	0.168583	0.015322	0.009049	
136											
137		Breakdown by Generating Plant									

Line No.	Description	Amount ($)	% of Total (%)
138			
139	Description	Amount ($)	% of Total (%)
140			
141	Production		
142	Dale	4,943,815	13.44
143	Cooper	6,053,604	16.46
144	Spurlock	15,008,756	40.80
145	Smith	867,010	2.36
146	Other	3,345,708	9.10
147		-	-
148	Subtotal--Production	30,218,893	82.16
149	Transmission	5,339,672	14.52
150	Distribution	598,965	1.63
151	Customer Accounting	-	-
152	Customer Service	621,810	1.69
153	Sales	3,283	0.01
154	Total (Excluding A&G)	36,782,622	100.00
155			

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Accumulated Reserves for Depreciation
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total as of 12/31/09 ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		**Intangible Plant**									
3		Organization	LABOR	-	-	-	-	-	-	-	
4		Franchises	LABOR	-							
5		Misc. Intang. Plant	TRANS	(588,159)	-	-	-	(588,159)	-	-	1
6		Subtotal - Intangible Plant		(588,159)	-	-	-	(588,159)	-	-	Sum(L3 : L5)
7											
8		**Production Plant**									
9		Steam									
10	108	Land & Land Rights	2	(2,321,695)	(2,259,426)	-	(62,269)	-	-	-	
11	108	Struct. & Improve.	2	(60,125,374)	(59,063,856)	-	(1,061,518)	-	-	-	
12	108	Boiler Plant Equip.	2	(383,317,994)	(374,279,412)	-	(9,038,582)	-	-	-	
13	108	Engines & Gen.	2	-							
14	108	Turbogenerator Units	2	(67,832,035)	(67,832,035)	-	-	-	-	-	
15	108	Access. Elec. Equip.	2	(22,880,952)	(22,857,154)	-	(23,797)	-	-	-	
16	108	Misc. Plant Equipment	2	(1,598,502)	(1,559,804)	-	(38,698)	-	-	-	
17		Subtotal		(538,076,551)	(527,851,686)	-	(10,224,865)	-	-	-	Sum(L10 : L16)
18		Nuclear									
19	108	Land & Land Rights		-							
20	108	Struct. & Improve.		-							
21	108	Reactor Plant Equip.		-							
22	108	Turbogenerator Units		-							
23	108	Access. Elec. Equip.		-							
24	108	Misc. Plant Equipment		-							
25		Subtotal		-	-	-	-	-	-	-	Sum(L19 : L24)
26		Hydraulic									
27	108	Land & Land Rights		-							
28	108	Struct. & Improve.		-							
29	108	Rsrvr Dams & Strwys		-							
30	108	Wheels Turb. & Gen.		-							
31	108	Accessory Electrical Equip.		-							
32	108	Misc. Plant Equipment		-							
33	108	Rds RR & Bridges		-							
34		Subtotal		-	-	-	-	-	-	-	Sum(L27 : L33)
35		Other									
36	108	Land & Land Rights	PROD_OTH_PLNT	(1,229,975)	(1,229,975)	-	-	-	-	-	
37	108	Struct. & Improve.	PROD_OTH_PLNT	(8,824,666)	(8,824,666)	-	-	-	-	-	
38	108	Prod. & Access.	PROD_OTH_PLNT	(3,713,556)	(3,713,556)	-	-	-	-	-	
39	108	Prime Movers	PROD_OTH_PLNT	(40,137,471)	(40,137,471)	-	-	-	-	-	
40	108	Generators	PROD_OTH_PLNT	(13,425,669)	(13,425,669)	-	-	-	-	-	
41	108	Access. Elec. Equip.	PROD_OTH_PLNT	(4,851,354)	(4,851,354)	-	-	-	-	-	
42	108	Misc. Plant Equip.	PROD_OTH_PLNT	(1,527,450)	(1,527,450)	-	-	-	-	-	
43		Subtotal		(73,710,140)	(73,710,140)	-		-			Sum(L36 : L42)
44		Subtotal--Production		(611,786,692)	(601,561,827)	-	(10,224,865)	-	-	-	L17 + L43

1 Accumulated reserves for depreciation associated with interconnections with other utilities.
2 Prorate based on plant investment in each account.

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Accumulated Reserves for Depreciation
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total as of 12/31/09 ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
45											
46		Transmission									
47	108	Land & Land Rights	2	(14,087,207.88)	-	-	-	(14,087,208)	-	-	
48	108	Struct. & Improve.	2	-							
49	108	Station Equip.	1	(52,339,960)	(4,291,585)	-	-	(46,165,773)	-	(1,882,601)	
50	108	Towers & Fixtures	2	(1,171,981.43)	-	-	-	(1,171,981)	-	-	
51	108	Poles & Fixtures	2	(39,266,199.29)	-	-	-	(39,266,199)	-	-	
52	108	OH Cond. & Devices	2	(27,881,032.36)	-	-	-	(27,881,032)	-	-	
53	108	UG Conduit	2	-							
54	108	UG Cond. & Devices	2	-							
55	108	Roads & Trails	2	(6,989.13)	-	-	-	(6,989)	-	-	
56		Subtotal - Transmission		(134,753,370)	(4,291,585)	-	-	(128,579,183)	-	(1,882,601)	Sum(L47 : L55)
57											
58		Distribution									
59	108	Land & Land Rights	2	(2,134,214.43)	-	-	-	-	(2,134,214)	-	
60	108	Struct. & Improve.	2	-							
61	108	Station Equip.	2	(40,345,627.75)	-	-	-	-	(40,345,628)	-	
62	108	Stor. Battery Equip.	2	-							
63	108	Poles Tower & Fix.	2	-							
64	108	OH Cond. & Devices	2	-							
65	108	UG Conduit	2	-							
66	108	UG Cond. & Devices	2	-							
67	108	Line Transformers	2	(364,816.52)	-	-	-	-	(364,817)	-	
68	108	Services	2	-							
69	108	Meters	2	-							
70	108	Install on Cust. Ld	2	-							
71	108	Leased Ld from Cust.	2	-							
72	108	Street Light & Signal	2	-							
73		Subtotal - Distribution		(42,844,659)	-	-	-	-	(42,844,659)	-	Sum(L59 : L72)
74											
75		Subtotal - Prod. Trans. Dist Plant		(746,540,061)	(605,853,412)	-	(10,224,865)	(128,579,183)	-	(1,882,601)	L44 + L56 + L73
76		General									
77	108	Land & Land Rights	2	(591,220.47)	(242,558)	(227,477)	(7,107)	(99,669)	(9,059)	(5,350)	
78	108	Struct. & Improve.	2	(9,995,932.59)	(4,100,996)	(3,846,020)	(120,166)	(1,685,140)	(153,157)	(90,455)	
79	108	Off. Furn. & Equip.	2	(4,472,338.76)	(1,834,851)	(1,720,770)	(53,764)	(753,958)	(68,525)	(40,471)	
80	108	Transp. Equip.	2	(4,935,145.47)	(2,024,725)	(1,898,839)	(59,328)	(831,979)	(75,616)	(44,659)	
81	108	Stores Equip.	2	(103,458.34)	(42,445)	(39,806)	(1,244)	(17,441)	(1,585)	(936)	
82	108	Shop & Garage Equip.	2	(1,087,075.04)	(445,990)	(418,261)	(13,068)	(183,262)	(16,656)	(9,837)	
83	108	Lab Equip.	2	(1,730,372.19)	(709,914)	(665,775)	(20,802)	(291,711)	(26,513)	(15,658)	
84	108	Power Op. Equip.	2	(5,890,558.82)	(2,416,699)	(2,266,442)	(70,813)	(993,045)	(90,255)	(53,305)	
85	108	Communication Equip.	2	(20,383,454.39)	(8,362,647)	(7,842,706)	(245,039)	(3,436,294)	(312,315)	(184,453)	
86	108	Misc. Equip.	2	(825,206.49)	(338,555)	(317,505)	(9,920)	(139,115)	(12,644)	(7,467)	
87	108	Other Tangible Prop.	2	-							
88	108	Subtotal-General Plant		(50,014,763)	(20,519,379)	(19,243,602)	(601,250)	(8,431,615)	(766,325)	(452,592)	Sum(L77 : L87)
89											
90		Grand Total		(839,987,642)	(626,372,791)	(19,243,602)	(10,826,115)	(137,598,957)	(43,610,984)	(2,335,193)	L75 + L88

[1] Depreciation Reserves associated with distribution meters are direct assigned, with the remainder assigned based on plant investment in that account.

East Kentucky Power Cooperative, Inc.
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(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		Plant in Service		3,083,650,873	2,406,990,027	28,349,957	41,120,643	444,061,586	157,719,914	5,408,745	Ex. B, pg. 2
3		Accum. Depr. Reserves		(839,987,642)	(626,372,791)	(19,243,602)	(10,826,115)	(137,598,957)	(43,610,984)	(2,335,193)	Ex. C, pg. 2
4		Net Plant		2,243,663,231	1,780,617,237	9,106,355	30,294,528	306,462,629	114,108,931	3,073,552	L2 - L3
5	107	Construction Work in Progress									
6	107	Production-Steam	PROD_PEAKER	170,641,685	48,223,340	122,418,345	-	-	-	-	
7	107	Production-Steam Service Related	STEAM_SERV	32,149,860	8,652,905	21,966,009	1,530,946	-	-	-	
8	107	Production-Other	PROD_OTH_PLNT	139,910,500	139,910,500	-	-	-	-	-	
9	107	Transmission	TRANS	29,201,072				29,201,072			
10	107	Distribution Substations	DIST_SUB	6,979,845					6,979,845		
11	107	Ditstribution Meters	DIST_METER	96,876						96,876	
12	107	General Plant	LABOR	3,863,509	1,585,068	1,486,518	46,445	651,320	59,197	34,962	
13	107	Total CWIP		382,843,347	198,371,813	145,870,872	1,577,391	29,852,392	7,039,042	131,838	Sum(L6:L12)
14	108	Retirement Work in Progress	DIRECT	2,687,087	1,421,537	-		1,446,942	(181,392)		
15	108	Retirement Work in Progress	LABOR	18,201	7,467	7,003	219	3,068	279	165	
16		Adjusted Net Plant		2,623,801,290	1,977,560,046	154,970,223	31,871,700	334,865,010	121,329,085	3,205,225	L4+L13+L14-L15
17											
18	165	Prepayments	NET_PLNT	1,571,678	1,247,316	6,379	21,221	214,676	79,933	2,153	
19											
20	151	Fuel Stocks	FUEL_EXP	69,903,296	-	68,199,716	1,703,580	-	-	-	
21											
22		Materials and Supplies									
23	154	Production-Steam	PROD_STM_PLNT	25,053,337	24,577,258	-	476,079	-	-	-	
24	154	Production-Other	PROD_OTH_PLNT	617,287	617,287	-	-	-	-	-	
25	154	ETS	PROD_CAP	58,916	58,916						
26	154	Transmission	TRANS_PLNT	10,658,752	342,548	-	-	10,203,634	-	112,570	
27	154	Distribution Subtation	DIST_SUB	3,777,628	-	-	-	-	3,777,628	-	
28	154	Distribution Meters	DIST_METER								
29	154	General Plant	LABOR	1,049	430	404	13	177	16	9	
30		Subtotal--M&S		40,166,969	25,596,439	404	476,092	10,203,811	3,777,644	112,580	Sum(L23 : L29)
31											
32		Cash Working Capital (1/8)									
33		Production Expense									
34		Total		62,143,777	7,457,031	53,294,260	1,108,886	268,442	2,748	12,410	Exhibit A, pg. 2
35		Less: Fuel		37,115,060	-	36,210,546	904,514	-	-	-	Ex. A, pg. 1&2
36		Less: Purch. Power		9,929,559	-	9,929,559	-	-	-	-	Ex. A, pg. 2
37		Net Production		15,099,159	7,457,031	7,154,155	204,373	268,442	2,748	12,410	L34 - L35 - L36
38		Transmission O&M		3,730,511	43,429	-	-	3,622,124	-	64,958	Ex. A, pg. 2
39		Distribution O&M		209,536	-	-	-	-	193,744	15,792	Ex. A, pg. 2
40		Customer Accounts		-	-	-	-	-	-	-	Ex. A, pg. 2
41		Customer Service & Info.		249,456	-	249,456	-	-	-	-	Ex. A, pg. 3
42		Sales		763	-	763	-	-	-	-	Ex. A, pg. 3
43		Administrative & General		3,698,606	1,517,414	1,423,070	44,463	623,520	56,670	33,469	Ex. A, pg. 3
44		Subtotal--CWC		22,988,030	9,017,874	8,827,444	248,835	4,514,086	253,162	126,629	Sum(L37 : L43)
45											
46		Total Rate Base		2,758,431,263	2,013,421,675	232,004,165	34,321,429	349,797,583	125,439,824	3,446,586	L16 + L18+L20+
47											L30+L44
48				2,243,663,231	1,780,617,237	9,106,355	30,294,528	306,462,629	114,108,931	3,073,552	L4
49			NET_PLNT	1.000000	0.793621	0.004059	0.013502	0.136590	0.050858	0.001370	
50											
51				2,758,431,263	2,013,421,675	232,004,165	34,321,429	349,797,583	125,439,824	3,446,586	L46
52			RATE BASE	1.000000	0.729915	0.084107	0.012442	0.126810	0.045475	0.001249	
53											
54			STEAM_SERV	1.000000	0.269143	0.683238	0.047619				Workpaper WP-4

East Kentucky Power Cooperative, Inc.
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(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		**Power Production**									
3		Steam									1
4	500	Oper. Super. & Eng.	PROD_CAP	7,594,038 [2]	7,482,541		111,497				1
5	501	Fuel	PROD_ENG	278,856,859		271,620,750	7,236,109				1
6	502	Steam	PROD_CAP	9,135,440	9,005,031		130,409				1
7	503	Steam-Other Sources	PROD_CAP			-					1
8	504	Steam Transferred	PROD_CAP			-					1
9	505	Electric	PROD_CAP	4,949,188 [2]	4,891,224		57,964				1
10	506	Misc. Steam Power	PROD_CAP	24,293,270 [2]	23,884,908		408,362				1
11	507	Rents	PROD_CAP		-						1
12	509	Allowances	PROD_ENG	10,432,273		10,327,853	104,420				1
13	510	Main. Super. & Eng.	PROD_ENG	2,571,560		2,530,152	41,408				1
14	511	Main. Struct.	PROD_CAP	3,021,229	2,973,480		47,749				1
15	512	Main. Boiler Plant	PROD_ENG	31,487,461 [2]		30,816,643	670,818				1
16	513	Main. Electric Plant	PROD_ENG	8,866,053 [2]		8,809,914	56,139				1
17	514	Main. Misc. Plant	PROD_CAP	124,139	123,571		568				
18											
19		Nuclear									
20	517	Oper. Super. & Eng.									
21	518	Nuclear Fuel									
22	519	Coolants & Water									
23	520	Steam Exp.									
24	521	Steam - Other Sources									
25	522	Steam Transferred									
26	523	Electric									
27	524	Misc. Nuclear Power									
28	525	Rents									
29	528	Main. Super. & Eng.									
30	529	Main. Struct.									
31	530	Main. Reactor Plant									
32	531	Main. Electric Plant									
33	532	Main. Misc. Plant									
34											
35		Hydraulic									
36	535	Oper. Super. & Eng.									
37	536	Water for Power									
38	537	Hydraulic									
39	538	Electric									
40	539	Misc. Hydr. Power									
41	540	Rents									
42	541	Main. Super. & Eng.									
43	542	Main. Struct.									
44	543	Main. Waterways									
45	544	Main. Electric Plant									
46	545	Main. Misc. Hydr. Plant									

[1] Allocate O&M expense for the steam production related expense to Steam Service. See Workpaper WP-4. Assign the remainder in accordance with FERC standard methodology.

[2] Includes annualizing adjustments for 1) Spurlock No. 1 Scrubber, and Spurlock No. 4 which were commercial for only part of 2009. See Workpaper WP-22.

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Revenue Requirements
Calendar 2009
(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total (\$)	(f) Production Capacity (\$)	(g) Production Energy (\$)	(h) Production Steam Direct (\$)	(i) Transm. (\$)	(j) Distribution Substations (\$)	(k) Distribution Meters (\$)	(l) Notes
47											
48		Power Production (Con't.)									
49		Other									
50	546	Oper. Super. & Eng.	PROD_CAP	379,440	379,440						1
51	547	Fuel	PROD_ENG	18,063,618		18,063,618					1
52	548	Generation	PROD_CAP	3,174,159	3,174,159						1
53	549	Misc. Other Power	PROD_CAP	885,220	885,220						1
54	550	Rents	PROD_CAP		-						1
55	551	Main. Super. & Eng.	PROD_CAP	27,230	27,230						1
56	552	Main. Struct.	PROD_CAP	138,759	138,759						1
57	553	Main. Gen. & Elec. Plant	PROD_CAP	2,794,902	2,794,902						1
58	554	Main. Misc. Other Power	PROD_CAP	98,814	98,814						1
59											
60		Other Power Supply									
61	555	Purchased Power	PROD_ENG [1]	79,436,469 [2]		79,436,469					
62	556	System Control & Dispatch		3,643,003	182,150	1,275,051		2,087,190		98,612	
63	557	Other Expenses	DIRECT	6,754,754	3,281,126	3,473,628					4
64	557	Other Expenses	PTD_PLNT	422,340	333,694	-	5,649	60,347	21,985	666	4
65											
66		Subtotal - Production		497,150,217	59,656,249	426,354,077	8,871,092	2,147,536	21,985	99,278	Sum(L4 : L64)
67											
68		Transmission									
69	560	Oper. Super. & Eng.	TRANS_OM	2,922,646	69,705	-	-	2,748,681	-	104,260	
70	561	Load Dispatching	5	2,536,940				2,213,134		323,806	
71	562	Oper. Station	TRANS_STA	2,524,182	164,562	-	-	2,305,541	-	54,079	
72	563	Oper. OH Line	TRANS_LINES	1,690,707	-	-	-	1,690,707	-	-	
73	564	Oper. UG Line	TRANS_LINES		-	-	-	-	-	-	
74	565	Trans of Electricity - Others	TRANS	14,828,464				14,828,464			
75	566	Misc. Transmission Oper.	TRANS	567,938				567,938			
76	567	Rents	TRANS	448,288				448,288			
77	568	Main. Super. & Eng.	TRANS_OM	11,834	282	-	-	11,130	-	422	
78	569	Main. Structures	TRANS					-			
79	570	Main. Station Equipment	TRANS_STA	1,731,481	112,882	-	-	1,581,502	-	37,096	
80	571	Main. OH Lines	TRANS_LINES	2,530,289	-	-	-	2,530,289	-	-	
81	572	Main. UG Lines	TRANS_LINES		-	-	-	-	-	-	
82	573	Main. Misc. Trans. Plant	TRANS	51,317				51,317			
83											
84		Subtotal - Transmission		29,844,086	347,432	-	-	28,976,990	-	519,664	Sum(L69 : L82)

1 Breakdown provided by EKPC. See Workpapers WP-7 and WP-11.
4 Assign DLC expenses to PROD_CAP, and expenses related to power supply and ACES brokerage fees to PROD_ENG. See Workpaper WP-18. Assign the remainder of Acct. 557 based on PTD_PLNT.
5 See Workpaper WP-7 for the metering expense. Assign the remainder to Transmission.

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Revenue Requirements
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(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
85											
86		**Distribution**									
87	580	Oper. Super. & Eng.	DIST_SUB						-		
88	581	Load Dispatching	6	161,957					35,623	126,334	
89	582	Station	DIST_SUB	589,810					589,810		
90	583	OH Line	DIST_SUB						-		
91	584	UG Line	DIST_SUB						-		
92	585	Street Light & Signal System	DIST_SUB						-		
93	586	Meters	DIST_SUB						-		
94	587	Customer Installation	DIST_SUB						-		
95	588	Misc. Operations	DIST_SUB						-		
96	589	Rents	DIST_SUB						-		
97	590	Main. Super. & Eng.	DIST_SUB						-		
98	591	Main. Struct.	DIST_SUB						-		
99	592	Main. Station Equipment	DIST_SUB	924,519					924,519		
100	593	Main. OH Lines	DIST_SUB						-		
101	594	Main. UG Lines	DIST_SUB						-		
102	595	Main. Line Transf.	DIST_SUB						-		
103	596	Main. Street Light & Signal	DIST_SUB						-		
104	597	Main. Meters	DIST_SUB						-		
105	598	Misc. Maintenance	DIST_SUB						-		
106											
107		Subtotal - Distribution		1,676,285	-	-	-	-	1,549,951	126,334	Sum(L87 : L105)
108											
109		**Customer Accounts**									
110	901	Supervision	PROD_ENG			-					
111	902	Meter Reading	PROD_ENG			-					
112	903	Cust. Rec. & Coll.	PROD_ENG			-					
113	904	Uncollectible Accts.	PROD_ENG			-					
114	905	Misc. Cust. Accts.	PROD_ENG			-					
115											
116		Subtotal - Cust. Accts.		-	-	-	-	-	-	-	Sum(L110 : L114)
117											
118		**Customer Service & Info.**									
119	907	Supervision	PROD_ENG			-					
120	908	Cust. Assistance	PROD_ENG	1,983,731		1,983,731					
121	909	Advertising	PROD_ENG	11,054		11,054					
122	910	Misc. Serv. & Info.	PROD_ENG	864		864					
123											
124		Subtotal - Cust. Serv. & Info.		1,995,650	-	1,995,650	-	-	-	-	Sum(L109 : L123)
125											
126		**Sales**									
127	911	Supervision	PROD_ENG			-					
128	912	Demo. & Selling	PROD_ENG			-					
129	913	Advertising	PROD_ENG	6,101		6,101					
130	916	Misc. Sales	PROD_ENG			-					
131											
132		Subtotal - Sales		6,101	-	6,101	-	-	-	-	Sum(L127 : L130)

6 See Workpaper WP-7 for metering expense. Assign the remainder to Distribution Substations.

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Revenue Requirements
Calendar 2009
(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
133											
134		**Administrative & General**									
135	920	Salaries	LABOR	10,362,927	4,251,561	3,987,224	124,577	1,747,008	158,781	93,776	
136	921	Off. Supplies & Exp.	LABOR	4,901,663	2,010,988	1,885,956	58,925	826,335	75,103	44,356	
137	922	Admin. Transferred	LABOR		-	-	-	-	-	-	
138	923	Outside Services	LABOR	4,864,798	1,995,863	1,871,772	58,482	820,120	74,538	44,022	
139	924	Property Insurance	NET_PLNT		-	-	-	-	-	-	
140	925	Injuries & Damages	LABOR	2,005,367	822,735	771,582	24,107	338,070	30,726	18,147	
141	926	Pensions & Benefits	LABOR	1,032,872	423,753	397,406	12,417	174,124	15,826	9,347	
142	927	Franchise Req.	LABOR		-	-	-	-	-	-	
143	928	Reg. Commission	LABOR	1,215,150	498,535	467,539	14,608	204,853	18,619	10,996	
144	929	Duplicate Charges	LABOR	(483,399)	(198,322)	(185,992)	(5,811)	(81,493)	(7,407)	(4,374)	
145	930	Misc. General Expense	LABOR	4,755,366	1,950,967	1,829,667	57,166	801,672	72,862	43,032	
146	931	Rents	LABOR		-	-	-	-	-	-	
147	935	Main. Gen. Plant	LABOR	934,103	383,231	359,404	11,229	157,474	14,312	8,453	
148											
149		Subtotal - Administration & General		29,588,847	12,139,311	11,384,559	355,701	4,988,162	453,360	267,754	Sum(L135 : L147)
150											
151		Subtotal - Operating Expense		560,261,186	72,142,992	439,740,387	9,226,793	36,112,689	2,025,296	1,013,030	L66+L84 + L107 + L116 + L124 + L132 + L149
152											
153		**Depreciation**									
154	405	Intangible	INTG_PLNT	51,882	59	55	2	51,762	2	1	
155	403	Production-Steam	PROD_STM_PLNT	42,483,027	41,675,738	-	807,289	-	-	-	
156	403	Production-Other	PROD_OTH_PLNT	6,599,313	6,599,313	-	-	-	-	-	
157	403	Transmission	TRANS_PLNT	5,717,499	183,747	-	-	5,473,368	-	60,384	
158	403	Distribution	DIST_PLNT	4,867,035	-	-	-	-	4,867,035	-	
159	403	General	PTD_PLNT	4,061,000	1,666,092	1,562,504	48,819	684,614	62,223	36,749	
160											
161		Subtotal - Depreciation		63,779,756	50,124,949	1,562,559	856,110	6,209,743	4,929,260	97,134	Sum(L154 : L159)
162											
163		**Taxes**									
164	408	Property--Production		-							7
165	408	Property--Transmission		-							7
166	408	Property--Distribution		-							7
167	408	Property--General Plant		-							7
168	408	Payroll & Other	LABOR	800	328	308	10	135	12	7	7
169											
170		Subtotal - Taxes		800	328	308	10	135	12	7	Sum(L164 : L168)
171											
172	431	**Interest - Other**	NET_PLNT	35,781	28,397	145	483	4,887	1,820	49	
173											
174		**Other Deductions**									
175	426	EPA Penalties	FUEL_EXP	4,937,772	-	4,817,436	120,336	-	-	-	
176	428	Amort. Debt Exp. & Disc.	RATE_BASE	1,171,644	855,201	98,544	14,578	148,577	53,281	1,464	
177	426	Other	LABOR	1,098,105	450,516	422,505	13,201	185,121	16,825	9,937	
178											
179		Total Expenses		631,285,044	123,602,383	446,641,884	10,231,510	42,661,152	7,026,494	1,121,621	L151+L161 + L170 + L172 + L174
180											

7 Property tax is allocated back to the functional areas in Accounts 500 to 935.

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Revenue Requirements
Calendar 2009
(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
181											
182		**Return Requirements**									
183		Rate Base		2,758,431,263	2,013,421,675	232,004,165	34,321,429	349,797,583	125,439,824	3,446,586	Exhibit D, L46
184		Rate of Return		5.7708%	5.7708%	5.7708%	5.7708%	5.7708%	5.7708%	5.7708%	L188 / L187
185		Return Requirements		159,182,649	116,189,879	13,388,420	1,980,610	20,186,004	7,238,840	198,894	L183 * L184
186		Interest Expense	RATE_BASE	113,319,764	82,713,850	9,531,018	1,409,967	14,370,117	5,153,223	141,590	
187		Margin Requirements	RATE_BASE	45,862,885	33,476,029	3,857,403	570,643	5,815,888	2,085,617	57,304	TIER = 1.40
188		Total Return Requirements		159,182,649	116,189,879	13,388,420	1,980,610	20,186,004	7,238,840	198,894	L186 + L187
189											
190		**Total Gross Revenue Requirements**		790,467,693	239,792,262	460,030,304	12,212,120	62,847,156	14,265,334	1,320,516	L179 + L185
191											
192		TIER		1.40							
193		Operating TIER		1.33							
194											
195		**Revenue/Non-Operating Income Credits**									
196	447	Sales for Resale--Non-Mem.	As Billed	9,844,534	-	9,844,534					Workpaper WP-9
197	454	Other Electric Revenue	DIRECT	14,544,659	6,463,805	5,263,478	244,230	2,561,129	12,017	-	Workpaper WP-10
198		Interest Income	RATE_BASE	3,615,136	2,638,744	304,059	44,981	458,437	164,399	4,517	
199		AFUDC	RATE_BASE	4,883,872	3,564,814	410,769	60,767	619,325	222,094	6,102	
200		Cap. Credits & Pat.Dividend	RATE_BASE	264,435	193,015	22,241	3,290	33,533	12,025	330	
201		Other Non Operating Inc.	RATE_BASE	(59,871)	(43,701)	(5,036)	(745)	(7,592)	(2,723)	(75)	
202		Salt River Generation Credit	Direct	(534,105)	(92,830)	(441,275)					
203		Subtotal - Rev. Credits		32,558,660	12,723,847	15,398,771	352,523	3,664,832	407,812	10,875	Sum(L195 : L201)
204											
205		**Net Member Revenue Requirements**		757,909,033	227,068,415	444,631,534	11,859,597	59,182,325	13,857,522	1,309,641	L190 - L203
206											
207		**Average Cost - Control Area**									
208		Total Member-System Billing Units (excludes Inland Steam)									
209		12 CP Demand (MW-mo)			26,904			26,904			Form 12b
210		Energy (MWh)		11,969,336	11,969,336	11,969,336		11,969,336			Form 12b
211		No. Substations							312		
212		Average Cost Total Member Systems									
213		Demand ($/kW/mo)			8.44			2.20			
214		Energy ($/MWh)		63.32	18.97	37.15		4.94			
215		Per Substation ($/Sub/mo)							3,701	350	
216											
217		**Allocation Factors Based on Revenue Requirements**									
218		Fuel Expense		296,920,476	-	289,684,367	7,236,109	-	-	-	
219			FUEL_EXP	1.000000	0.000000	0.975629	0.024371	0.000000	0.000000	0.000000	
220											
221		Transmission O&M		11,632,854	277,444	-	-	10,940,428	-	414,982	Sum(L70:L73) + L75 +
222			TRANS_OM	1.000000	0.023850	0.000000	0.000000	0.940477	0.000000	0.035673	Sum(L78:L82)
223											
224	s	The targeted TIER is designed to match Member Revenue Requirements to Member Revenue Under Present Rates.									
225		Member Revenue Under Present Rates		757,909,033							
226		Other Operating Revenue		23,855,088							L196 + L197
227		Non Operating Income		8,703,572							Sum(L198 : L201)
228		Total Income		790,467,693							Sum(L225 : L227)
229		Less: Operating Expenses		631,285,044							L179
230		Net Revenue		159,182,649							L228 - L229
231		Interest Expense		113,319,764							L186
232		Implied TIER		1.40							L230 / L231

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Plant in Service
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total as of 12/31/09 [1] ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		**Intangible Plant**									
3	301	Organization	LABOR	5,040	2,065	1,942	61	850	77	46	
4	302	Franchises	LABOR		-	-	-	-	-	-	
5	303	Misc. Intang. Plant	TRANS	1,815,946				1,815,946			2
6		Subtotal - Intangible Plant		1,820,987	2,065	1,942	61	1,816,796	77	46	Sum(L3 : L5)
7											
8		**Production Plant**									
9		Steam									
10	310	Land & Land Rights	3	9,135,877	2,505,151	6,359,502	271,224				
11	311	Struct. & Improve.	3	236,593,520	65,554,700	166,415,222	4,623,599				
12	312	Boiler Plant Equip.	3	1,508,357,416	415,136,161	1,053,852,378	39,368,877				
13	313	Engines & Gen.	3	-	-	-	-				
14	314	Turbogenerator Units	3	266,919,252	75,431,381	191,487,872	-				
15	315	Access. Elec. Equip.	3	90,036,611	25,415,054	64,517,904	103,653				
16	316	Misc. Plant Equipment	3	6,290,109	1,729,952	4,391,604	168,554				
17		Subtotal		2,117,332,785	585,772,398	1,487,024,481	44,535,907	-	-	-	Sum(L10 : L16)
18		Nuclear									
19	320	Land & Land Rights									
20	321	Struct. & Improve.									
21	322	Reactor Plant Equip.									
22	323	Turbogenerator Units									
23	324	Access. Elec. Equip.									
24	325	Misc. Plant Equipment									
25		Subtotal		-	-	-	-	-	-	-	Sum(L19 : L24)
26		Hydraulic									
27	330	Land & Land Rights									
28	331	Struct. & Improve.									
29	332	Rsrvr Dams & Strwys									
30	333	Wheels Turb. & Gen.									
31	334	Accessory Electrical Equip.									
32	335	Misc. Plant Equipment									
33	336	Rds RR & Bridges									
34		Subtotal		-	-	-	-	-	-	-	Sum(L27 : L33)
35		Other									
36	340	Land & Land Rights	PROD_OTH_PLNT	4,759,583	4,759,583	-	-	-	-	-	
37	341	Struct. & Improve.	PROD_OTH_PLNT	34,148,434	34,148,434	-	-	-	-	-	
38	342	Prod. & Access.	PROD_OTH_PLNT	14,370,188	14,370,188	-	-	-	-	-	
39	343	Prime Movers	PROD_OTH_PLNT	155,318,256	155,318,256	-	-	-	-	-	
40	344	Generators	PROD_OTH_PLNT	51,952,739	51,952,739	-	-	-	-	-	
41	345	Access. Elec. Equip.	PROD_OTH_PLNT	18,773,076	18,773,076	-	-	-	-	-	
42	346	Misc. Plant Equip.	PROD_OTH_PLNT	5,910,707	5,910,707	-	-	-	-	-	
43		Subtotal		285,232,982	285,232,982	-	-	-	-	-	Sum(L36 : L42)
44		Subtotal--Production		2,402,565,767	871,005,380	1,487,024,481	44,535,907	-	-	-	L17 + L43

[1] Includes Acct. 106. Plant Completed Not Yet Classified. See Workpaper WP-6. Also, includes plant investment recovered through the Environmental Surcharge.
[2] Intangible plant related to interconnections with other utilities. See Workpaper WP-21.
[3] Investment in Steam Plant facilities has been assigned first directly to Inland Steam, (see Workpaper WP-4), with the remainder allocated using PROD_PEAKER

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Plant in Service
Calendar 2009
(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total as of 12/31/09 [1] ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
45											
46		**Transmission**									
47	350	Land & Land Rights	TRANS_PLNT	46,938,315				46,938,315			
48	352	Struct. & Improve.	TRANS_PLNT					-			
49	353	Station Equip.	[4]	174,395,774	14,429,684			155,224,110		4,741,980	[5]
50	354	Towers & Fixtures	TRANS_PLNT	3,905,020				3,905,020			
51	355	Poles & Fixtures	TRANS_PLNT	130,834,247				130,834,247			
52	356	OH Cond. & Devices	TRANS_PLNT	92,899,082				92,899,082			
53	357	UG Conduit	TRANS_PLNT					-			
54	358	UG Cond. & Devices	TRANS_PLNT					-			
55	359	Roads & Trails	TRANS_PLNT	23,288				23,288			
56		Subtotal - Transmission		448,995,725	14,429,684	-	-	429,824,061	-	4,741,980	Sum(L47 : L55)
57											
58		**Distribution**									
59	360	Land & Land Rights	DISTSUB_PLANT	7,800,241					7,800,241		
60	361	Struct. & Improve.							-		
61	362	Station Equip.	DISTSUB_PLANT	147,457,361					147,457,361		
62	363	Stor. Battery Equip.							-		
63	364	Poles Tower & Fix.							-		
64	365	OH Cond. & Devices							-		
65	366	UG Conduit							-		
66	367	UG Cond. & Devices							-		
67	368	Line Transformers	DISTSUB_PLANT	1,333,351					1,333,351		
68	369	Services							-		
69	370	Meters							-		
70	371	Install on Cust. Ld							-		
71	372	Leased Ld from Cust.							-		
72	373	Street Light & Signal							-		
73		Subtotal - Distribution		156,590,953	-	-	-	-	156,590,953	-	Sum(L59 : L72)
74											
75		Subtotal - Prod, Trans, Dist Plant		3,008,152,446	885,435,064	1,487,024,481	44,535,907	429,824,061	156,590,953	4,741,980	L44 + L56 + L73
76											
77		**General**									
78	389	Land & Land Rights	LABOR	870,935	356,821	335,593	10,471	146,824	13,344	7,881	
79	390	Struct. & Improve.	LABOR	14,725,147	6,032,867	5,673,967	177,042	2,482,402	225,618	133,250	
80	391	Off. Furn. & Equip.	LABOR	6,588,264	2,699,201	2,538,623	79,211	1,110,666	100,945	59,618	
81	392	Transp. Equip.	LABOR	7,270,031	2,978,519	2,801,325	87,408	1,225,600	111,391	65,788	
82	393	Stores Equip.	LABOR	152,406	62,440	58,726	1,832	25,693	2,335	1,379	
83	394	Shop & Garage Equip.	LABOR	1,601,385	656,085	617,054	19,254	269,966	24,536	14,491	
84	395	Lab Equip.	LABOR	2,549,035	1,044,335	982,207	30,647	429,723	39,056	23,067	
85	396	Power Op. Equip.	LABOR	8,677,464	3,555,142	3,343,644	104,330	1,462,869	132,956	78,524	
86	397	Communication Equip.	LABOR	30,027,149	12,302,071	11,570,211	361,019	5,062,052	460,075	271,721	
87	398	Misc. Equip.	LABOR	1,215,623	498,039	468,410	14,616	204,933	18,626	11,000	
88	399	Other Tangible Prop.	LABOR	-	-	-	-	-	-	-	
89		Subtotal-General Plant		73,677,440	30,185,521	28,389,758	885,831	12,420,729	1,128,884	666,719	Sum(L78 : L88)
90											
91		Grand Total		3,083,650,873	915,622,649	1,515,416,181	45,421,798	444,061,586	157,719,914	5,408,745	L44 + L56 + L89
92											

[4] Distribution meters and Generator step Up Transformers are direct assigned, with the remainder assigned to Transmission. Distribution meters includeds $35,557 in Plant Completed Not Yet Classified.

[5] Distribution meter investment does not include meters installed on portable substations.

Exhibit A
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East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Plant in Service
Calendar 2009
(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total as of 12/31/09 [1]	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
93											
94		**Allocation Factors Based on Plant**									
95	301-303	Intangible Plant		1,820,987	2,065	1,942	61	1,816,796	77	46	L6
96			INTG_PLNT	1.000000	0.001134	0.001067	0.000033	0.997699	0.000042	0.000025	
97											
98	310-316	Production Plant--Steam		2,117,332,785	585,772,398	1,487,024,481	44,535,907	-	-	-	L17
99			PROD_STM_PLNT	1.000000	0.276656	0.702310	0.021034	-	-	-	
100											
101			PROD_CAP	1.000000	1.000000	0.000000					
102			PROD_PEAKER	1.000000	0.282600	0.717400	Applies only to production steam plant				
103			PROD_AED	1.000000	0.390561	0.609439	Applies to all production plant				
104											
105	340-346	Production Plant--Other		285,232,982	285,232,982	-	-	-	-	-	L43
106			PROD_OTH_PLNT	1.000000	1.000000	0.000000					
107											
108	301-346	Total Production Plant		2,402,565,767	871,005,380	1,487,024,481	44,535,907	-	-	-	L44
109			PROD_PLNT	1.000000	0.362531	0.618932	0.018537	0.000000	0.000000	0.000000	
110											
111	353	Transmission Stations		221,334,089	14,429,684	-	-	202,162,425	-	4,741,980	Sum(L47:L49)
112			TRANS_STA	1.000000	0.065194	0.000000	0.000000	0.913381	0.000000	0.021425	
113											
114	354-358	Transmission Lines		227,638,349	-	-	-	227,638,349	-	-	Sum(L50:L55)
115			TRANS_LINES	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	
116											
117	350-359	Total Transmission Plant		448,995,725	14,429,684	-	-	429,824,061	-	4,741,980	L56
118			TRANS_PLNT	1.000000	0.032138	0.000000	0.000000	0.957301	0.000000	0.010561	
119											
120	360-373	Distribution Plant		156,590,953	-	-	-	-	156,590,953	-	L73
121			DISTSUB_PLNT	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	
122											
123	301-373	Prod. Trans. Dist Plant		3,008,152,446	885,435,064	1,487,024,481	44,535,907	429,824,061	156,590,953	4,741,980	L75
124			PTD_PLNT	1.000000	0.294345	0.494331	0.014805	0.142886	0.052056	0.001576	
125											
126	301-399	Total Gross Plant		3,083,650,873	915,622,649	1,515,416,181	45,421,798	444,061,586	157,719,914	5,408,745	L91
127			GROSS_PLNT	1.000000	0.29692812	0.49143572	0.01472988	0.14400514	0.05114714	0.00175401	
128											

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Payroll Expense
Calendar 2009

Note: Labor expense is allocated on the same basis as the corresponding expense.

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		**Power Production**									
3		Steam									
4	500	Oper. Super. & Eng.		4,634,976	4,566,924	-	68,052	-	-	-	
5	501	Fuel		3,102,961	-	3,022,441	80,519	-	-	-	
6	502	Steam		3,609,377	3,557,853	-	51,524	-	-	-	
7	503	Steam-Other Sources									
8	504	Steam Transferred									
9	505	Electric		2,960,651	2,925,976	-	34,675	-	-	-	
10	506	Misc. Steam Power		1,613,121	1,586,005	-	27,116	-	-	-	
11	507	Rents									
12	510	Main. Super. & Eng.		1,802,051	-	1,773,034	29,017	-	-	-	
13	511	Main. Struct.		439,291	432,348	-	6,943	-	-	-	
14	512	Main. Boiler Plant		6,291,880	-	6,157,836	134,044	-	-	-	
15	513	Main. Electric Plant		1,495,446	-	1,485,977	9,469	-	-	-	
16	514	Main. Misc. Plant		56,422	56,164	-	258	-	-	-	
17											
18		Nuclear									
19	517	Oper. Super. & Eng.									
20	518	Nuclear Fuel									
21	519	Coolants & Water									
22	520	Steam Exp.									
23	521	Steam - Other Sources									
24	522	Steam Transferred									
25	523	Electric									
26	524	Misc. Nuclear Power									
27	525	Rents									
28	528	Main. Super. & Eng.									
29	529	Main. Struct.									
30	530	Main. Reactor Plant									
31	531	Main. Electric Plant									
32	532	Main. Misc. Plant									
33											
34		Hydraulic									
35	535	Oper. Super. & Eng.									
36	536	Water for Power									
37	537	Hydraulic									
38	538	Electric									
39	539	Misc. Hydr. Power									
40	540	Rents									
41	541	Main. Super. & Eng.									
42	542	Main. Struct.									
43	543	Main. Waterways									
44	544	Main. Electric Plant									
45	545	Main. Misc. Hydr. Plant									

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Payroll Expense
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
46											
47		**Power Production (Con't.)**									
48		**Other**									
49	546	Oper. Super. & Eng.		251,711	251,711	-	-	-	-	-	
50	547	Fuel			-	-	-	-	-	-	
51	548	Generation		791,054	791,054	-	-	-	-	-	
52	549	Misc. Other Power		205,497	205,497	-	-	-	-	-	
53	550	Rents				-	-	-	-	-	
54	551	Main. Super. & Eng.		16,947	16,947	-	-	-	-	-	
55	552	Main. Struct.		7,368	7,368	-	-	-	-	-	
56	553	Main. Gen. & Elec. Plant		104,586	104,586	-	-	-	-	-	
57	554	Main. Misc. Other Power		1,096	1,096	-	-	-	-	-	
58											
59		**Other Power Supply**									
60	555	Purchased Power (Net)			-	-	-	-	-	-	
61	556	System Control & Dispatch		2,118,102	105,905	741,336	-	1,213,526	-	57,335	
62	557	Other Expenses		716,357	339,902	367,546	624	6,023	2,194	66	
63											
64		Subtotal - Production		30,218,893	14,949,337	13,548,171	442,241	1,219,550	2,194	57,401	Sum(L4 : L62)
65											
66		**Transmission**									
67	560	Oper. Super. & Eng.		1,470,607	35,074	-	-	1,383,072	-	52,461	
68	561	Load Dispatching		1,231,141	-	-	-	1,074,003	-	157,138	
69	562	Oper. Station		781,484	50,948	-	-	713,793	-	16,743	
70	563	Oper. OH Line		456,603	-	-	-	456,603	-	-	
71	564	Oper. UG Line									
72	565	Trans of Electricity - Others			-	-	-	-	-	-	
73	566	Misc. Transmission Oper.		292,615	-	-	-	292,615	-	-	
74	567	Rents			-	-	-	-	-	-	
75	568	Main. Super. & Eng.		7,912	189	-	-	7,441	-	282	
76	569	Main. Struct.									
77	570	Main. Station Equip.		525,038	34,229	-	-	479,560	-	11,249	
78	571	Main. OH Lines		574,270	-	-	-	574,270	-	-	
79	572	Main. UG Lines									
80	573	Main. Misc. Trans. Plant			-	-	-	-	-	-	
81											
82		Subtotal - Transmission		5,339,672	120,440	-	-	4,981,357	-	237,874	Sum(L67 : L80)

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Payroll Expense
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
83											
84		**Distribution**									
85	580	Oper. Super. & Eng.		48,173	-	-	-	-	10,596	37,577	
86	581	Load Dispatching		250,750	-	-	-	-	250,750	-	
87	582	Station									
88	583	OH Line									
89	584	UG Line									
90	585	Street Light & Signal Sys.									
91	586	Meters									
92	587	Customer Installation									
93	588	Misc. Distribution									
94	589	Rents									
95	590	Main. Super. & Eng.									
96	591	Main. Struct.		300,042	-	-	-	-	300,042	-	
97	592	Main. Station Equipment									
98	593	Main. OH Lines									
99	594	Main. UG Lines									
100	595	Main. Line Transf.									
101	596	Main. Street Light & Sig.									
102	597	Main. Meters									
103	598	Main. Misc.									
104											
105		Subtotal - Distribution		598,965	-	-	-	-	561,388	37,577	
106											
107		**Customer Accounts**									
108	901	Supervision									
109	902	Meter Reading									
110	903	Cust. Rec. & Coll.									
111	904	Uncollectible Accts.									
112	905	Misc. Cust. Accts.									
113											
114		Subtotal - Cust. Accts.		-	-	-	-	-	-	-	Sum(L108 : L112)
115											
116		**Customer Service & Info.**		-							
117	907	Supervision		613,032	-	613,032		-			
118	908	Cust. Assistance		8,519	-	8,519		-			
119	909	Advertising		259	-	259		-			
120	910	Misc. Serv. & Info.									
121											
122		Subtotal - Cust. Service		621,810	-	621,810	-	-	-	-	Sum(L107 : L121)

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Payroll Expense
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
123											
124		**Sales**									
125	911	Supervision									
126	912	Demo. & Selling									
127	913	Advertising		3,283	-	3,283		-			
128	916	Misc. Sales									
129											
130		Subtotal - Sales		3,283	-	3,283	-	-	-	-	Sum(L125 : L128)
131											
132		**Summary**									
133		Total Labor (Excluding A&G)		36,782,622	15,069,777	14,173,263	442,241	6,200,907	563,582	332,852	L48+L66 + L89 + L98+L106+L130
134											
135		Labor Allocator	LABOR	1.000000	0.409698	0.385325	0.012023	0.168583	0.015322	0.009049	
136											
137		**Breakdown by Generating Plant**									
138					% of						
139		Description		Amount	Total						
140				($)	(%)						
141		Production									
142		Dale		4,943,815	13.44						
143		Cooper		6,053,604	16.46						
144		Spurlock		15,008,756	40.80						
145		Smith		867,010	2.36						
146		Other		3,345,708	9.10						
147					-						
148		Subtotal--Production		30,218,893	82.16						
149		Transmission		5,339,672	14.52						
150		Distribution		598,965	1.63						
151		Customer Accounting		-	-						
152		Customer Service		621,810	1.69						
153		Sales		3,283	0.01						
154		Total (Excluding A&G)		36,782,622	100.00						
155											

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East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Accumulated Reserves for Depreciation
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total as of 12/31/09 ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		**Intangible Plant**									
3		Organization	LABOR	-	-	-	-	-	-	-	
4		Franchises	LABOR	-							1
5		Misc. Intang. Plant	TRANS	(588,159)	-	-	-	(588,159)	-	-	
6		Subtotal - Intangible Plant		(588,159)	-	-	-	(588,159)	-	-	Sum(L3 : L5)
7											
8		**Production Plant**									
9		Steam									
10	108	Land & Land Rights	2	(2,321,695)	(636,633)	(1,616,137)	(68,926)	-	-	-	
11	108	Struct. & Improve.	2	(60,125,374)	(16,659,378)	(42,291,004)	(1,174,993)	-	-	-	
12	108	Boiler Plant Equip.	2	(383,317,994)	(105,498,312)	(267,814,893)	(10,004,790)	-	-	-	
13	108	Engines & Gen.	2	-							
14	108	Turbogenerator Units	2	(67,832,035)	(19,169,333)	(48,662,702)	-	-	-	-	
15	108	Access. Elec. Equip.	2	(22,880,952)	(6,458,713)	(16,395,897)	(26,341)	-	-	-	
16	108	Misc. Plant Equipment	2	(1,598,502)	(439,632)	(1,116,036)	(42,835)	-	-	-	
17		Subtotal		(538,076,551)	(148,861,999)	(377,896,668)	(11,317,884)	-	-	-	Sum(L10 : L16)
18		Nuclear									
19	108	Land & Land Rights		-							
20	108	Struct. & Improve.		-							
21	108	Reactor Plant Equip.		-							
22	108	Turbogenerator Units		-							
23	108	Access. Elec. Equip.		-							
24	108	Misc. Plant Equipment		-							
25		Subtotal		-	-	-	-	-	-	-	Sum(L19 : L24)
26		Hydraulic									
27	108	Land & Land Rights		-							
28	108	Struct. & Improve.		-							
29	108	Rsrvr Dams & Strwys		-							
30	108	Wheels Turb. & Gen.		-							
31	108	Accessory Electrical Equip.		-							
32	108	Misc. Plant Equipment		-							
33	108	Rds RR & Bridges		-							
34		Subtotal		-	-	-	-	-	-	-	Sum(L27 : L33)
35		Other									
36	108	Land & Land Rights	PROD_OTH_PLNT	(1,229,975)	(1,229,975)	-	-	-	-	-	
37	108	Struct. & Improve.	PROD_OTH_PLNT	(8,824,666)	(8,824,666)	-	-	-	-	-	
38	108	Prod. & Access.	PROD_OTH_PLNT	(3,713,556)	(3,713,556)	-	-	-	-	-	
39	108	Prime Movers	PROD_OTH_PLNT	(40,137,471)	(40,137,471)	-	-	-	-	-	
40	108	Generators	PROD_OTH_PLNT	(13,425,669)	(13,425,669)	-	-	-	-	-	
41	108	Access. Elec. Equip.	PROD_OTH_PLNT	(4,851,354)	(4,851,354)	-	-	-	-	-	
42	108	Misc. Plant Equip.	PROD_OTH_PLNT	(1,527,450)	(1,527,450)	-		-	-	-	
43		Subtotal		(73,710,140)	(73,710,140)	-		-			Sum(L36 : L42)
44		Subtotal--Production		(611,786,692)	(222,572,140)	(377,896,668)	(11,317,884)	-	-	-	L17 + L43

[1] Accumulated reserves for depreciation associated with interconnections with other utilities.

[2] Prorate based on plant investment in each account.

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Accumulated Reserves for Depreciation
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total as of 12/31/09 ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
45											
46		**Transmission**									
47	108	Land & Land Rights	2	(14,087,207.88)	-	-	-	(14,087,208)	-	-	
48	108	Struct. & Improve.	2	-							
49	108	Station Equip.	1	(52,339,960)	(4,291,585)	-	-	(46,165,773)	-	(1,882,601)	
50	108	Towers & Fixtures	2	(1,171,981.43)	-	-	-	(1,171,981)	-	-	
51	108	Poles & Fixtures	2	(39,266,199.29)	-	-	-	(39,266,199)	-	-	
52	108	OH Cond. & Devices	2	(27,881,032.36)	-	-	-	(27,881,032)	-	-	
53	108	UG Conduit	2	-							
54	108	UG Cond. & Devices	2	-							
55	108	Roads & Trails	2	(6,989.13)	-	-	-	(6,989)	-	-	
56		Subtotal - Transmission		(134,753,370)	(4,291,585)	-	-	(128,579,183)	-	(1,882,601)	Sum(L47 : L55)
57											
58		**Distribution**									
59	108	Land & Land Rights	2	(2,134,214.43)	-	-	-	-	(2,134,214)	-	
60	108	Struct. & Improve.	2	-							
61	108	Station Equip.	2	(40,345,627.75)	-	-	-	-	(40,345,628)	-	
62	108	Stor. Battery Equip.	2	-							
63	108	Poles Tower & Fix.	2	-							
64	108	OH Cond. & Devices	2	-							
65	108	UG Conduit	2	-							
66	108	UG Cond. & Devices	2	-							
67	108	Line Transformers	2	(364,816.52)	-	-	-	-	(364,817)	-	
68	108	Services	2	-							
69	108	Meters	2	-							
70	108	Install on Cust. Ld	2	-							
71	108	Leased Ld from Cust.	2	-							
72	108	Street Light & Signal	2	-							
73		Subtotal - Distribution		(42,844,659)	-	-	-	-	(42,844,659)	-	Sum(L59 : L72)
74											
75		Subtotal - Prod, Trans, Dist Plant		(746,540,061)	(226,863,725)	(377,896,668)	(11,317,884)	(128,579,183)	-	(1,882,601)	L44 + L56 + L73
76		**General**									
77	108	Land & Land Rights	2	(591,220.47)	(242,222)	(227,812)	(7,108)	(99,669)	(9,059)	(5,350)	
78	108	Struct. & Improve.	2	(9,995,932.59)	(4,095,316)	(3,851,682)	(120,182)	(1,685,140)	(153,157)	(90,455)	
79	108	Off. Furn. & Equip.	2	(4,472,338.76)	(1,832,309)	(1,723,304)	(53,771)	(753,958)	(68,525)	(40,471)	
80	108	Transp. Equip.	2	(4,935,145.47)	(2,021,921)	(1,901,635)	(59,336)	(831,979)	(75,616)	(44,659)	
81	108	Stores Equip.	2	(103,458.34)	(42,387)	(39,865)	(1,244)	(17,441)	(1,585)	(936)	
82	108	Shop & Garage Equip.	2	(1,087,075.04)	(445,373)	(418,877)	(13,070)	(183,262)	(16,656)	(9,837)	
83	108	Lab Equip.	2	(1,730,372.19)	(708,931)	(666,756)	(20,804)	(291,711)	(26,513)	(15,658)	
84	108	Power Op. Equip.	2	(5,890,558.82)	(2,413,352)	(2,269,779)	(70,823)	(993,045)	(90,255)	(53,305)	
85	108	Communication Equip.	2	(20,383,454.39)	(8,351,066)	(7,854,254)	(245,072)	(3,436,294)	(312,315)	(184,453)	
86	108	Misc. Equip.	2	(825,206.49)	(338,086)	(317,973)	(9,922)	(139,115)	(12,644)	(7,467)	
87	108	Other Tangible Prop.	2	-							
88	108	Subtotal-General Plant		(50,014,763)	(20,490,962)	(19,271,937)	(601,332)	(8,431,615)	(766,325)	(452,592)	Sum(L77 : L87)
89											
90		Grand Total		(839,987,642)	(247,354,687)	(397,168,605)	(11,919,216)	(137,598,957)	(43,610,984)	(2,335,193)	L75 + L88

[1] Depreciation Reserves associated with distribution meters are direct assigned, with the remainder assigned based on plant investment in that account.

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Rate Base
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		Plant in Service		3,083,650,873	915,622,649	1,515,416,181	45,421,798	444,061,586	157,719,914	5,408,745	Ex. B, pg. 2
3		Accum. Depr. Reserves		(839,987,642)	(247,354,687)	(397,168,605)	(11,919,216)	(137,598,957)	(43,610,984)	(2,335,193)	Ex. C, pg. 2
4		Net Plant		2,243,663,231	668,267,962	1,118,247,576	33,502,582	306,462,629	114,108,931	3,073,552	L2 - L3
5	107	Construction Work in Progress									
6	107	Production-Steam	PROD_PEAKER	170,641,685	48,223,340	122,418,345	-	-	-	-	
7	107	Production-Steam Service Related	STEAM_SERV	32,149,860	8,652,905	21,966,009	1,530,946	-	-	-	
8	107	Production-Other	PROD_OTH_PLNT	139,910,500	139,910,500	-	-	-	-	-	
9	107	Transmission	TRANS	29,201,072				29,201,072			
10	107	Distribution Substations	DIST_SUB	6,979,845					6,979,845		
11	107	Distribution Meters	DIST_METER	96,876						96,876	
12	107	General Plant	LABOR	3,863,509	1,582,873	1,488,707	46,451	651,320	59,197	34,962	
13	107	Total CWIP		382,843,347	198,369,618	145,873,060	1,577,397	29,852,392	7,039,042	131,838	Sum(L6:L12)
14	108	Retirement Work in Progress	DIRECT	2,687,087	1,421,537	-		1,446,942	(181,392)		
15	108	Retirement Work in Progress	LABOR	18,201	7,457	7,013	219	3,068	279	165	
16		Adjusted Net Plant		2,623,801,290	865,208,587	1,264,113,623	35,079,760	334,865,010	121,329,085	3,205,225	L4+L13+L14-L15
17											
18	165	Prepayments	NET_PLNT	1,571,678	468,119	783,328	23,468	214,676	79,933	2,153	
19											
20	151	Fuel Stocks	FUEL_EXP	69,903,296	-	68,199,716	1,703,580	-	-	-	
21											
22		Materials and Supplies									
23	154	Production-Steam	PROD_STM_PLNT	25,053,337	6,931,151	17,595,215	526,971	-	-	-	
24	154	Production-Other	PROD_OTH_PLNT	617,287	617,287	-	-	-	-	-	
25	154	ETS	PROD_CAP	58,916	58,916						
26	154	Transmission	TRANS_PLNT	10,658,752	342,548	-	-	10,203,634	-	112,570	
27	154	Distribution Subtation	DIST_SUB	3,777,628	-	-	-	-	3,777,628	-	
28	154	Distribution Meters	DIST_METER								
29	154	General Plant	LABOR	1,049	430	404	13	177	16	9	
30		Subtotal--M&S		40,166,969	7,950,331	17,595,619	526,984	10,203,811	3,777,644	112,580	Sum(L23 : L29)
31											
32		Cash Working Capital (1/8)									
33		Production Expense									
34		Total		62,143,777	7,430,859	53,320,357	1,108,962	268,442	2,748	12,410	Exhibit A, pg. 2
35		Less: Fuel		37,115,060	-	36,210,546	904,514	-	-	-	Ex. A, pg. 1&2
36		Less: Purch. Power		9,929,559	-	9,929,559	-	-	-	-	Ex. A, pg. 2
37		Net Production		15,099,159	7,430,859	7,180,252	204,448	268,442	2,748	12,410	L34 - L35 - L36
38		Transmission O&M		3,730,511	43,429	-	-	3,622,124	-	64,958	Ex. A, pg. 2
39		Distribution O&M		209,536	-	-	-	-	193,744	15,792	Ex. A, pg. 2
40		Customer Accounts		-	-	-	-	-	-	-	Ex. A, pg. 2
41		Customer Service & Info.		249,456	-	249,456	-	-	-	-	Ex. A, pg. 3
42		Sales		763	-	763	-	-	-	-	Ex. A, pg. 3
43		Administrative & General		3,698,606	1,515,312	1,425,165	44,469	623,520	56,670	33,469	Ex. A, pg. 3
44		Subtotal--CWC		22,988,030	8,989,600	8,855,636	248,917	4,514,086	253,162	126,629	Sum(L37 : L43)
45											
46		Total Rate Base		2,758,431,263	882,616,637	1,359,547,922	37,582,710	349,797,583	125,439,824	3,446,586	L16 + L18+L20+ L30+L44
47				2,243,663,231	668,267,962	1,118,247,576	33,502,582	306,462,629	114,108,931	3,073,552	L4
48			NET_PLNT	1.000000	0.297847	0.498403	0.014932	0.136590	0.050858	0.001370	
49											
50				2,758,431,263	882,616,637	1,359,547,922	37,582,710	349,797,583	125,439,824	3,446,586	L46
51			RATE BASE	1.000000	0.319971	0.492870	0.013625	0.126810	0.045475	0.001249	
52											
53			STEAM_SERV	1.000000	0.269143	0.683238	0.047619				
54											

Workpaper WP-4

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Revenue Requirements
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		Power Production									
3		Steam									
4	500	Oper. Super. & Eng.	PROD_CAP	7,594,038 [2]	7,482,541		111,497				1
5	501	Fuel	PROD_ENG	278,856,859		271,620,750	7,236,109				1
6	502	Steam	PROD_CAP	9,135,440	9,005,031		130,409				1
7	503	Steam-Other Sources	PROD_CAP			-					1
8	504	Steam Transferred	PROD_CAP			-					1
9	505	Electric	PROD_CAP	4,949,188 [2]	4,891,224		57,964				1
10	506	Misc. Steam Power	PROD_CAP	24,293,270 [2]	23,884,908		408,362				1
11	507	Rents	PROD_CAP		-						1
12	509	Allowances	PROD_ENG	10,432,273		10,327,853	104,420				1
13	510	Main. Super. & Eng.	PROD_ENG	2,571,560		2,530,152	41,408				1
14	511	Main. Struct.	PROD_CAP	3,021,229	2,973,480		47,749				1
15	512	Main. Boiler Plant	PROD_ENG	31,487,461 [2]		30,816,643	670,818				1
16	513	Main. Electric Plant	PROD_ENG	8,866,053 [2]		8,809,914	56,139				1
17	514	Main. Misc. Plant	PROD_CAP	124,139	123,571		568				1
18											
19		Nuclear									
20	517	Oper. Super. & Eng.									
21	518	Nuclear Fuel									
22	519	Coolants & Water									
23	520	Steam Exp.									
24	521	Steam - Other Sources									
25	522	Steam Transferred									
26	523	Electric									
27	524	Misc. Nuclear Power									
28	525	Rents									
29	528	Main. Super. & Eng.									
30	529	Main. Struct.									
31	530	Main. Reactor Plant									
32	531	Main. Electric Plant									
33	532	Main. Misc. Plant									
34											
35		Hydraulic									
36	535	Oper. Super. & Eng.									
37	536	Water for Power									
38	537	Hydraulic									
39	538	Electric									
40	539	Misc. Hydr. Power									
41	540	Rents									
42	541	Main. Super. & Eng.									
43	542	Main. Struct.									
44	543	Main. Waterways									
45	544	Main. Electric Plant									
46	545	Main. Misc. Hydr. Plant									

[1] Allocate O&M expense for the steam production related expense to Steam Service. See Workpaper WP-4. Assign the remainder in accordance with FERC standard methodology.

[2] Includes annualizing adjustments for 1) Spurlock No. 1 Scrubber, and Spurlock No. 4 which were commercial for only part of 2009. See Workpaper WP-22.

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Revenue Requirements
Calendar 2009
(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total (S)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct (S)	(i) Transm. (S)	(j) Distribution Substations (S)	(k) Distribution Meters (S)	(l) Notes
47											
48		**Power Production (Con't.)**									
49		**Other**									
50	546	Oper. Super. & Eng.	PROD_CAP	379,440	379,440						[1]
51	547	Fuel	PROD_ENG	18,063,618		18,063,618					[1]
52	548	Generation	PROD_CAP	3,174,159	3,174,159						[1]
53	549	Misc. Other Power	PROD_CAP	885,220	885,220						[1]
54	550	Rents	PROD_CAP		-						[1]
55	551	Main. Super. & Eng.	PROD_CAP	27,230	27,230						[1]
56	552	Main. Struct.	PROD_CAP	138,759	138,759						[1]
57	553	Main. Gen. & Elec. Plant	PROD_CAP	2,794,902	2,794,902						[1]
58	554	Main. Misc. Other Power		98,814	98,814						[1]
59											
60		**Other Power Supply**									
61	555	Purchased Power	PROD_ENG	79,436,469 [2]		79,436,469					
62	556	System Control & Dispatch	[3]	3,643,003	182,150	1,275,051		2,087,190		98,612	
63	557	Other Expenses	DIRECT	6,754,754	3,281,126	3,473,628					[4]
64	557	Other Expenses	PTD_PLNT	422,340	124,314	208,776	6,253	60,347	21,985	666	[4]
65											
66		Subtotal - Production		497,150,217	59,446,869	426,562,853	8,871,696	2,147,536	21,985	99,278	Sum(L4 : L64)
67											
68		Transmission									
69	560	Oper. Super. & Eng.	TRANS_OM	2,922,646	69,705	-	-	2,748,681	-	104,260	
70	561	Load Dispatching	[5]	2,536,940				2,213,134		323,806	
71	562	Oper. Station	TRANS_STA	2,524,182	164,562	-	-	2,305,541	-	54,079	
72	563	Oper. OH Line	TRANS_LINES	1,690,707	-	-	-	1,690,707	-	-	
73	564	Oper. UG Line	TRANS_LINES		-	-	-	-	-	-	
74	565	Trans of Electricity - Others	TRANS	14,828,464				14,828,464			
75	566	Misc. Transmission Oper.	TRANS	567,938				567,938			
76	567	Rents	TRANS	448,288				448,288			
77	568	Main. Super. & Eng.	TRANS_OM	11,834	282	-	-	11,130	-	422	
78	569	Main. Structures	TRANS					-			
79	570	Main. Station Equipment	TRANS_STA	1,731,481	112,882	-	-	1,581,502	-	37,096	
80	571	Main. OH Lines	TRANS_LINES	2,530,289	-	-	-	2,530,289	-	-	
81	572	Main. UG Lines	TRANS_LINES		-	-	-	-	-	-	
82	573	Main. Misc. Trans. Plant	TRANS	51,317				51,317			
83											
84		Subtotal - Transmission		29,844,086	347,432	-	-	28,976,990	-	519,664	Sum(L69 : L82)

[3] Breakdown provided by EKPC. See Workpapers WP-7 and WP-11.

[4] Assign DLC expenses to PROD_CAP, and expenses related to power supply and ACES brokerage fees to PROD_ENG. See Workpaper WP-18. Assign the remainder of Acct. 557 based on PTD_PLNT.

[5] See Workpaper WP-7 for the metering expense. Assign the remainder to Transmission.

East Kentucky Power Cooperative, Inc.
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(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
85											
86		**Distribution**									
87	580	Oper. Super. & Eng.	DIST_SUB						-		
88	581	Load Dispatching	[6]	161,957					35,623	126,334	
89	582	Station	DIST_SUB	589,810					589,810		
90	583	OH Line	DIST_SUB						-		
91	584	UG Line	DIST_SUB						-		
92	585	Street Light & Signal System	DIST_SUB						-		
93	586	Meters	DIST_SUB						-		
94	587	Customer Installation	DIST_SUB						-		
95	588	Misc. Operations	DIST_SUB						-		
96	589	Rents	DIST_SUB						-		
97	590	Main. Super. & Eng.	DIST_SUB						-		
98	591	Main. Struct.	DIST_SUB						-		
99	592	Main. Station Equipment	DIST_SUB	924,519					924,519		
100	593	Main. OH Lines	DIST_SUB						-		
101	594	Main. UG Lines	DIST_SUB						-		
102	595	Main. Line Transf.	DIST_SUB						-		
103	596	Main. Street Light & Signal	DIST_SUB						-		
104	597	Main. Meters	DIST_SUB						-		
105	598	Misc. Maintenance	DIST_SUB						-		
106											
107		Subtotal - Distribution		1,676,285	-	-	-	-	1,549,951	126,334	Sum(L87 : L105)
108											
109		**Customer Accounts**									
110	901	Supervision	PROD_ENG			-					
111	902	Meter Reading	PROD_ENG			-					
112	903	Cust. Rec. & Coll.	PROD_ENG			-					
113	904	Uncollectible Accts.	PROD_ENG			-					
114	905	Misc. Cust. Accts.	PROD_ENG			-					
115											
116		Subtotal - Cust. Accts.		-	-	-	-	-	-	-	Sum(L110 : L114)
117											
118		**Customer Service & Info.**									
119	907	Supervision	PROD_ENG			-					
120	908	Cust. Assistance	PROD_ENG	1,983,731		1,983,731					
121	909	Advertising	PROD_ENG	11,054		11,054					
122	910	Misc. Serv. & Info.	PROD_ENG	864		864					
123											
124		Subtotal - Cust. Serv. & Info.		1,995,650	-	1,995,650	-	-	-	-	Sum(L109 : L123)
125											
126		**Sales**									
127	911	Supervision	PROD_ENG			-					
128	912	Demo. & Selling	PROD_ENG			-					
129	913	Advertising	PROD_ENG	6,101		6,101					
130	916	Misc. Sales	PROD_ENG			-					
131											
132		Subtotal - Sales		6,101	-	6,101	-	-	-	-	Sum(L127 : L130)

[6] See Workpaper WP-7 for metering expense. Assign the remainder to Distribution Substations.

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(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total (S)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct (S)	(i) Transm. ($)	(j) Distribution Substations (S)	(k) Distribution Meters (S)	(l) Notes
133											
134		Administrative & General									
135	920	Salaries	LABOR	10,362,927	4,245,673	3,993,095	124,594	1,747,008	158,781	93,776	
136	921	Off. Supplies & Exp.	LABOR	4,901,663	2,008,203	1,888,733	58,933	826,335	75,103	44,356	
137	922	Admin. Transferred	LABOR		-	-	-	-	-	-	
138	923	Outside Services	LABOR	4,864,798	1,993,099	1,874,528	58,490	820,120	74,538	44,022	
139	924	Property Insurance	NET_PLNT		-	-	-	-	-	-	
140	925	Injuries & Damages	LABOR	2,005,367	821,595	772,718	24,111	338,070	30,726	18,147	
141	926	Pensions & Benefits	LABOR	1,032,872	423,166	397,991	12,418	174,124	15,826	9,347	
142	927	Franchise Req.	LABOR		-	-	-	-	-	-	
143	928	Reg. Commission	LABOR	1,215,150	497,845	468,228	14,610	204,853	18,619	10,996	
144	929	Duplicate Charges	LABOR	(483,399)	(198,048)	(186,266)	(5,812)	(81,493)	(7,407)	(4,374)	
145	930	Misc. General Expense	LABOR	4,755,366	1,948,265	1,832,361	57,174	801,672	72,862	43,032	
146	931	Rents	LABOR		-	-	-	-	-	-	
147	935	Main. Gen. Plant	LABOR	934,103	382,701	359,933	11,231	157,474	14,312	8,453	
148											
149		Subtotal - Administration & General		29,588,847	12,122,500	11,401,322	355,749	4,988,162	453,360	267,754	Sum(L135 : L147)
150											
151		Subtotal - Operating Expense		560,261,186	71,916,801	439,965,926	9,227,445	36,112,689	2,025,296	1,013,030	L66+L84 + L107 + L116 + L124 + L132 + L149
152											
153		Depreciation									
154	405	Intangible	INTG_PLNT	51,882	59	55	2	51,762	2	1	
155	403	Production-Steam	PROD_STM_PLNT	42,483,027	11,753,176	29,836,265	893,587	-	-	-	
156	403	Production-Other	PROD_OTH_PLNT	6,599,313	6,599,313	-	-	-	-	-	
157	403	Transmission	TRANS_PLNT	5,717,499	183,747	-	-	5,473,368	-	60,384	
158	403	Distribution	DIST_PLNT	4,867,035	-	-	-	-	4,867,035	-	
159	403	General	PTD_PLNT	4,061,000	1,663,785	1,564,805	48,826	684,614	62,223	36,749	
160											
161		Subtotal - Depreciation		63,779,756	20,200,080	31,401,125	942,414	6,209,743	4,929,260	97,134	Sum(L154 : L159)
162											
163		Taxes									
164	408	Property--Production		-							7
165	408	Property--Transmission		-							7
166	408	Property--Distribution		-							7
167	408	Property--General Plant		-							7
168	408	Payroll & Other	LABOR	800	328	308	10	135	12	7	7
169											
170		Subtotal - Taxes		800	328	308	10	135	12	7	Sum(L164 : L168)
171											
172	431	Interest - Other	NET_PLNT	35,781	10,657	17,833	534	4,887	1,820	49	
173											
174		Other Deductions									
175	426	EPA Penalties	FUEL_EXP	4,937,772	-	4,817,436	120,336	-	-	-	
176	428	Amort. Debt Exp. & Disc.	RATE_BASE	1,171,644	374,892	577,468	15,963	148,577	53,281	1,464	
177	426	Other	LABOR	1,098,105	449,892	423,127	13,203	185,121	16,825	9,937	
178											
179		Total Expenses		631,285,044	92,952,649	477,203,223	10,319,905	42,661,152	7,026,494	1,121,621	L151+L161 + L170 + L172 + L174
180											

7 Property tax is allocated back to the functional areas in Accounts 500 to 935.

East Kentucky Power Cooperative, Inc.
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(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
181											
182		**Return Requirements**									
183		Rate Base		2,758,431,263	882,616,637	1,359,547,922	37,582,710	349,797,583	125,439,824	3,446,586	Exhibit D, L46
184		Rate of Return		5.7708%	5.7708%	5.7708%	5.7708%	5.7708%	5.7708%	5.7708%	L188 / L187
185		Return Requirements		159,182,649	50,933,752	78,456,347	2,168,811	20,186,004	7,238,840	198,894	L183 * L184
186		Interest Expense	RATE_BASE	113,319,764	36,258,982	55,851,908	1,543,944	14,370,117	5,153,223	141,590	
187		Margin Requirements	RATE_BASE	45,862,885	14,674,770	22,604,438	624,867	5,815,888	2,085,617	57,304	TIER = 1.40
188		Total Return Requirements		159,182,649	50,933,752	78,456,347	2,168,811	20,186,004	7,238,840	198,894	L186 + L187
189											
190		**Total Gross Revenue Requirements**		790,467,693	143,886,401	555,659,570	12,488,716	62,847,156	14,265,334	1,320,516	L179 + L185
191											
192		TIER		1.40							
193		Operating TIER		1.33							
194											
195		**Revenue/Non-Operating Income Credits**									
196	447	Sales for Resale--Non-Mem.	As Billed	9,844,534	-	9,844,534					Workpaper WP-9
197	454	Other Electric Revenue	DIRECT	14,544,659	1,930,847	9,783,363	257,303	2,561,129	12,017	-	Workpaper WP-10
198		Interest Income	RATE_BASE	3,615,136	1,156,737	1,781,792	49,255	458,437	164,399	4,517	
199		AFUDC	RATE_BASE	4,883,872	1,562,695	2,407,114	66,541	619,325	222,094	6,102	
200		Cap. Credits & Pat.Dividend	RATE_BASE	264,435	84,611	130,332	3,603	33,533	12,025	330	
201		Other Non Operating Inc.	RATE_BASE	(59,871)	(19,157)	(29,509)	(816)	(7,592)	(2,723)	(75)	
202		Salt River Generation Credit	Direct	(534,105)	(92,830)	(441,275)					
203		Subtotal - Rev. Credits		32,558,660	4,622,904	23,476,351	375,887	3,664,832	407,812	10,875	Sum(L195 : L201)
204											
205		**Net Member Revenue Requirements**		**757,909,033**	**139,263,497**	**532,183,219**	**12,112,829**	**59,182,325**	**13,857,522**	**1,309,641**	L190 - L203
206											
207		**Average Cost - Control Area**									
208		Total Member-System Billing Units (excludes Inland Steam)									
209		12 CP Demand (MW-mo)			26,904			26,904			Form 12b
210		Energy (MWh)		11,969,336	11,969,336	11,969,336		11,969,336			Form 12b
211		No. Substations							312		
212		Average Cost Total Member Systems									
213		Demand ($/kW/mo)			5.18			2.20			
214		Energy ($/MWh)		63.32	11.64	44.46		4.94			
215		Per Substation ($/Sub/mo)							3,701	350	
216											
217		**Allocation Factors Based on Revenue Requirements**									
218		Fuel Expense		296,920,476	-	289,684,367	7,236,109	-	-	-	
219			FUEL_EXP	1.000000	0.000000	0.975629	0.024371	0.000000	0.000000	0.000000	
220											
221		Transmission O&M		11,632,854	277,444	-	-	10,940,428	-	414,982	Sum(L70:L73) + L75 +
222			TRANS_OM	1.000000	0.023850	0.000000	0.000000	0.940477	0.000000	0.035673	Sum(L78:L82)
223											
224	*	The targeted TIER is designed to match Member Revenue Requirements to Member Revenue Under Present Rates.									
225		Member Revenue Under Present Rates		757,909,033							
226		Other Operating Revenue		23,855,088							L196 + L197
227		Non Operating Income		8,703,572							Sum(L198 : L201)
228		Total Income		790,467,693							Sum(L225 : L227)
229		Less: Operating Expenses		631,285,044							L179
230		Net Revenue		159,182,649							L228 - L229
231		Interest Expense		113,319,764							L186
232		Implied TIER		1.40							L230 / L231

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(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total as of 12/31/09 [1] ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		**Intangible Plant**									
3	301	Organization	LABOR	5,040	2,065	1,942	61	850	77	46	
4	302	Franchises	LABOR		-	-	-	-	-	-	
5	303	Misc. Intang. Plant	TRANS	1,815,946				1,815,946			[2]
6		Subtotal - Intangible Plant		1,820,987	2,065	1,942	61	1,816,796	77	46	Sum(L3 : L5)
7											
8		**Production Plant**									
9		Steam									
10	310	Land & Land Rights	[3]	9,135,877	3,463,726	5,404,869	267,282				
11	311	Struct. & Improve.	[3]	236,593,520	90,624,616	141,412,502	4,556,402				
12	312	Boiler Plant Equip.	[3]	1,508,357,416	573,952,889	895,607,815	38,796,712				
13	313	Engines & Gen.	[3]	-	-	-	-				
14	314	Turbogenerator Units	[3]	266,919,252	104,248,212	162,671,040	-				
15	315	Access. Elec. Equip.	[3]	90,036,611	35,124,898	54,809,609	102,104				
16	316	Misc. Plant Equipment	[3]	6,290,109	2,391,797	3,732,209	166,104				
17		Subtotal		2,117,332,785	809,806,138	1,263,638,044	43,888,604	-	-	-	Sum(L10 : L16)
18		Nuclear									
19	320	Land & Land Rights									
20	321	Struct. & Improve.									
21	322	Reactor Plant Equip.									
22	323	Turbogenerator Units									
23	324	Access. Elec. Equip.									
24	325	Misc. Plant Equipment									
25		Subtotal		-	-	-	-	-	-	-	Sum(L19 : L24)
26		Hydraulic									
27	330	Land & Land Rights									
28	331	Struct. & Improve.									
29	332	Rsrvr Dams & Strwys									
30	333	Wheels Turb. & Gen.									
31	334	Accessory Electrical Equip.									
32	335	Misc. Plant Equipment									
33	336	Rds RR & Bridges									
34		Subtotal		-	-	-	-	-	-	-	Sum(L27 : L33)
35		Other									
36	340	Land & Land Rights	PROD_OTH_PLNT	4,759,583	4,759,583	-	-	-	-	-	
37	341	Struct. & Improve.	PROD_OTH_PLNT	34,148,434	34,148,434	-	-	-	-	-	
38	342	Prod. & Access.	PROD_OTH_PLNT	14,370,188	14,370,188	-	-	-	-	-	
39	343	Prime Movers	PROD_OTH_PLNT	155,318,256	155,318,256	-	-	-	-	-	
40	344	Generators	PROD_OTH_PLNT	51,952,739	51,952,739	-	-	-	-	-	
41	345	Access. Elec. Equip.	PROD_OTH_PLNT	18,773,076	18,773,076	-	-	-	-	-	
42	346	Misc. Plant Equip.	PROD_OTH_PLNT	5,910,707	5,910,707	-	-	-	-	-	
43		Subtotal		285,232,982	285,232,982	-	-	-	-	-	Sum(L36 : L42)
44		Subtotal--Production		2,402,565,767	1,095,039,120	1,263,638,044	43,888,604	-	-	-	L17 + L43

[1] Includes Acct. 106, Plant Completed Not Yet Classified. See Workpaper WP-6. Also, includes plant investment recovered through the Environmental Surcharge.

[2] Intangible plant related to interconnections with other utilities. See Workpaper WP-21.

[3] Investment in Steam Plant facilities has been assigned first directly to Inland Steam, (see Workpaper WP-4), with the remainder allocated using PROD_PEAKER

East Kentucky Power Cooperative, Inc.
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(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total as of 12/31/09 [1] ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
45											
46		**Transmission**									
47	350	Land & Land Rights	TRANS_PLNT	46,938,315				46,938,315			
48	352	Struct. & Improve.	TRANS_PLNT					-			
49	353	Station Equip.	4	174,395,774	14,429,684			155,224,110		4,741,980	5
50	354	Towers & Fixtures	TRANS_PLNT	3,905,020				3,905,020			
51	355	Poles & Fixtures	TRANS_PLNT	130,834,247				130,834,247			
52	356	OH Cond. & Devices	TRANS_PLNT	92,899,082				92,899,082			
53	357	UG Conduit	TRANS_PLNT					-			
54	358	UG Cond. & Devices	TRANS_PLNT					-			
55	359	Roads & Trails	TRANS_PLNT	23,288				23,288			
56		Subtotal - Transmission		448,995,725	14,429,684	-	-	429,824,061	-	4,741,980	Sum(L47 : L55)
57											
58		**Distribution**									
59	360	Land & Land Rights	DISTSUB_PLANT	7,800,241					7,800,241		
60	361	Struct. & Improve.							-		
61	362	Station Equip.	DISTSUB_PLANT	147,457,361					147,457,361		
62	363	Stor. Battery Equip.							-		
63	364	Poles Tower & Fix.							-		
64	365	OH Cond. & Devices							-		
65	366	UG Conduit							-		
66	367	UG Cond. & Devices							-		
67	368	Line Transformers	DISTSUB_PLANT	1,333,351					1,333,351		
68	369	Services							-		
69	370	Meters							-		
70	371	Install on Cust. Ld							-		
71	372	Leased Ld from Cust.							-		
72	373	Street Light & Signal							-		
73		Subtotal - Distribution		156,590,953	-	-	-	-	156,590,953	-	Sum(L59 : L72)
74											
75		Subtotal - Prod. Trans. Dist Plant		3,008,152,446	1,109,468,804	1,263,638,044	43,888,604	429,824,061	156,590,953	4,741,980	L44 + L56 + L73
76											
77		**General**									
78	389	Land & Land Rights	LABOR	870,935	356,895	335,519	10,471	146,824	13,344	7,881	
79	390	Struct. & Improve.	LABOR	14,725,147	6,034,124	5,672,714	177,038	2,482,402	225,618	133,250	
80	391	Off. Furn. & Equip.	LABOR	6,588,264	2,699,763	2,538,062	79,210	1,110,666	100,945	59,618	
81	392	Transp. Equip.	LABOR	7,270,031	2,979,140	2,800,706	87,406	1,225,600	111,391	65,788	
82	393	Stores Equip.	LABOR	152,406	62,453	58,713	1,832	25,693	2,335	1,379	
83	394	Shop & Garage Equip.	LABOR	1,601,385	656,221	616,917	19,253	269,966	24,536	14,491	
84	395	Lab Equip.	LABOR	2,549,035	1,044,553	981,990	30,647	429,723	39,056	23,067	
85	396	Power Op. Equip.	LABOR	8,677,464	3,555,883	3,342,905	104,328	1,462,869	132,956	78,524	
86	397	Communication Equip.	LABOR	30,027,149	12,304,634	11,567,655	361,012	5,062,052	460,075	271,721	
87	398	Misc. Equip.	LABOR	1,215,623	498,142	468,306	14,615	204,933	18,626	11,000	
88	399	Other Tangible Prop.	LABOR		-	-	-	-	-	-	
89		Subtotal-General Plant		73,677,440	30,191,809	28,383,487	885,812	12,420,729	1,128,884	666,719	Sum(L78 : L88)
90											
91		Grand Total		3,083,650,873	1,139,662,678	1,292,023,473	44,774,477	444,061,586	157,719,914	5,408,745	L44 + L56 + L89
92											

[4] Distribution meters and Generator step Up Transformers are direct assigned, with the remainder assigned to Transmission. Distribution meters includeds $35,557 in Plant Completed Not Yet Classified.
[5] Distribution meter investment does not include meters installed on portable substations.

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Plant in Service
Calendar 2009
(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total as of 12/31/09 [1]	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
93											
94		**Allocation Factors Based on Plant**									
95	301-303	Intangible Plant		1,820,987	2,065	1,942	61	1,816,796	77	46	L6
96			INTG_PLNT	1.000000	0.001134	0.001066	0.000033	0.997699	0.000042	0.000025	
97											
98	310-316	Production Plant--Steam		2,117,332,785	809,806,138	1,263,638,044	43,888,604	-	-	-	L17
99			PROD_STM_PLNT	1.000000	0.382465	0.596807	0.020728	-	-	-	
100											
101			PROD_CAP	1.000000	1.000000	0.000000					
102			PROD_PEAKER	1.000000	0.282600	0.717400	Applies only to production steam plant				
103			PROD_AED	1.000000	0.390561	0.609439	Applies to all production plant				
104											
105	340-346	Production Plant--Other		285,232,982	285,232,982	-	-	-	-	-	L43
106			PROD_OTH_PLNT	1.000000	1.000000	0.000000					
107											
108	301-346	Total Production Plant		2,402,565,767	1,095,039,120	1,263,638,044	43,888,604	-	-	-	L44
109			PROD_PLNT	1.000000	0.455779	0.525954	0.018267	0.000000	0.000000	0.000000	
110											
111	353	Transmission Stations		221,334,089	14,429,684	-	-	202,162,425	-	4,741,980	Sum(L47:L49)
112			TRANS_STA	1.000000	0.065194	0.000000	0.000000	0.913381	0.000000	0.021425	
113											
114	354-358	Transmission Lines		227,638,349	-	-	-	227,638,349	-	-	Sum(L50:L55)
115			TRANS_LINES	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	
116											
117	350-359	Total Transmission Plant		448,995,725	14,429,684	-	-	429,824,061	-	4,741,980	L56
118			TRANS_PLNT	1.000000	0.032138	0.000000	0.000000	0.957301	0.000000	0.010561	
119											
120	360-373	Distribution Plant		156,590,953	-	-	-	-	156,590,953	-	L73
121			DISTSUB_PLNT	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	
122											
123	301-373	Prod. Trans. Dist Plant		3,008,152,446	1,109,468,804	1,263,638,044	43,888,604	429,824,061	156,590,953	4,741,980	L75
124			PTD_PLNT	1.000000	0.368821	0.420071	0.014590	0.142886	0.052056	0.001576	
125											
126	301-399	Total Gross Plant		3,083,650,873	1,139,662,678	1,292,023,473	44,774,477	444,061,586	157,719,914	5,408,745	L91
127			GROSS_PLNT	1.000000	0.36958227	0.41899149	0.01451996	0.14400514	0.05114714	0.00175401	
128											

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Payroll Expense
Calendar 2009

Note: Labor expense is allocated on the same basis as the corresponding expense.

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		Power Production									
3		Steam									
4	500	Oper. Super. & Eng.		4,634,976	4,566,924	-	68,052	-	-	-	
5	501	Fuel		3,102,961	-	3,022,441	80,519	-	-	-	
6	502	Steam		3,609,377	3,557,853	-	51,524	-	-	-	
7	503	Steam-Other Sources									
8	504	Steam Transferred									
9	505	Electric		2,960,651	2,925,976	-	34,675	-	-	-	
10	506	Misc. Steam Power		1,613,121	1,586,005	-	27,116	-	-	-	
11	507	Rents									
12	510	Main. Super. & Eng.		1,802,051	-	1,773,034	29,017	-	-	-	
13	511	Main. Struct.		439,291	432,348	-	6,943	-	-	-	
14	512	Main. Boiler Plant		6,291,880	-	6,157,836	134,044	-	-	-	
15	513	Main. Electric Plant		1,495,446	-	1,485,977	9,469	-	-	-	
16	514	Main. Misc. Plant		56,422	56,164	-	258	-	-	-	
17											
18		Nuclear									
19	517	Oper. Super. & Eng.									
20	518	Nuclear Fuel									
21	519	Coolants & Water									
22	520	Steam Exp.									
23	521	Steam - Other Sources									
24	522	Steam Transferred									
25	523	Electric									
26	524	Misc. Nuclear Power									
27	525	Rents									
28	528	Main. Super. & Eng.									
29	529	Main. Struct.									
30	530	Main. Reactor Plant									
31	531	Main. Electric Plant									
32	532	Main. Misc. Plant									
33											
34		Hydraulic									
35	535	Oper. Super. & Eng.									
36	536	Water for Power									
37	537	Hydraulic									
38	538	Electric									
39	539	Misc. Hydr. Power									
40	540	Rents									
41	541	Main. Super. & Eng.									
42	542	Main. Struct.									
43	543	Main. Waterways									
44	544	Main. Electric Plant									
45	545	Main. Misc. Hydr. Plant									

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Payroll Expense
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
46											
47		**Power Production (Con't.)**									
48		**Other**									
49	546	Oper. Super. & Eng.		251,711	251,711	-	-	-	-	-	
50	547	Fuel			-	-	-	-	-	-	
51	548	Generation		791,054	791,054	-	-	-	-	-	
52	549	Misc. Other Power		205,497	205,497	-	-	-	-	-	
53	550	Rents									
54	551	Main. Super. & Eng.		16,947	16,947	-	-	-	-	-	
55	552	Main. Struct.		7,368	7,368	-	-	-	-	-	
56	553	Main. Gen. & Elec. Plant		104,586	104,586	-	-	-	-	-	
57	554	Main. Misc. Other Power		1,096	1,096	-	-	-	-	-	
58											
59		**Other Power Supply**									
60	555	Purchased Power (Net)			-	-	-	-	-	-	
61	556	System Control & Dispatch		2,118,102	105,905	741,336	-	1,213,526	-	57,335	
62	557	Other Expenses		716,357	343,042	364,416	615	6,023	2,194	66	
63											
64		Subtotal - Production		30,218,893	14,952,476	13,545,040	442,232	1,219,550	2,194	57,401	Sum(L4 : L62)
65											
66		Transmission									
67	560	Oper. Super. & Eng.		1,470,607	35,074	-	-	1,383,072	-	52,461	
68	561	Load Dispatching		1,231,141	-	-	-	1,074,003	-	157,138	
69	562	Oper. Station		781,484	50,948	-	-	713,793	-	16,743	
70	563	Oper. OH Line		456,603	-	-	-	456,603	-	-	
71	564	Oper. UG Line									
72	565	Trans of Electricity - Others			-	-	-	-	-	-	
73	566	Misc. Transmission Oper.		292,615	-	-	-	292,615	-	-	
74	567	Rents			-	-	-	-	-	-	
75	568	Main. Super. & Eng.		7,912	189	-	-	7,441	-	282	
76	569	Main. Struct.									
77	570	Main. Station Equip.		525,038	34,229	-	-	479,560	-	11,249	
78	571	Main. OH Lines		574,270	-	-	-	574,270	-	-	
79	572	Main. UG Lines									
80	573	Main. Misc. Trans. Plant			-	-	-	-	-	-	
81											
82		Subtotal - Transmission		5,339,672	120,440	-	-	4,981,357	-	237,874	Sum(L67 : L80)

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Payroll Expense
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
83											
84		**Distribution**									
85	580	Oper. Super. & Eng.									
86	581	Load Dispatching		48,173	-	-	-	-	10,596	37,577	
87	582	Station		250,750	-	-	-	-	250,750	-	
88	583	OH Line									
89	584	UG Line									
90	585	Street Light & Signal Sys.									
91	586	Meters									
92	587	Customer Installation									
93	588	Misc. Distribution									
94	589	Rents									
95	590	Main. Super. & Eng.									
96	591	Main. Struct.									
97	592	Main. Station Equipment		300,042	-	-	-	-	300,042	-	
98	593	Main. OH Lines									
99	594	Main. UG Lines									
100	595	Main. Line Transf.									
101	596	Main. Street Light & Sig.									
102	597	Main. Meters									
103	598	Main. Misc.									
104											
105		Subtotal - Distribution		598,965	-	-	-	-	561,388	37,577	
106											
107		**Customer Accounts**									
108	901	Supervision									
109	902	Meter Reading									
110	903	Cust. Rec. & Coll.									
111	904	Uncollectible Accts.									
112	905	Misc. Cust. Accts.									
113											
114		Subtotal - Cust. Accts.		-	-	-	-	-	-	-	Sum(L108 : L112)
115											
116		**Customer Service & Info.**									
117	907	Supervision		-							
118	908	Cust. Assistance		613,032	-	613,032		-			
119	909	Advertising		8,519	-	8,519		-			
120	910	Misc. Serv. & Info.		259	-	259		-			
121											
122		Subtotal - Cust. Service		621,810	-	621,810	-	-	-	-	Sum(L107 : L121)

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Payroll Expense
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
123											
124		Sales									
125	911	Supervision									
126	912	Demo. & Selling									
127	913	Advertising		3,283	-	3,283		-			
128	916	Misc. Sales									
129											
130		Subtotal - Sales		3,283	-	3,283	-	-	-	-	Sum(L125 : L128)
131											
132		Summary									
133		Total Labor (Excluding A&G)		36,782,622	15,072,916	14,170,132	442,232	6,200,907	563,582	332,852	L48+L66 + L89 + L98+L106+L130
134											
135		Labor Allocator	LABOR	1.000000	0.409784	0.385240	0.012023	0.168583	0.015322	0.009049	
136											
137		Breakdown by Generating Plant									
138					% of						
139		Description		Amount	Total						
140				($)	(%)						
141		Production									
142		Dale		4,943,815	13.44						
143		Cooper		6,053,604	16.46						
144		Spurlock		15,008,756	40.80						
145		Smith		867,010	2.36						
146		Other		3,345,708	9.10						
147					-						
148		Subtotal--Production		30,218,893	82.16						
149		Transmission		5,339,672	14.52						
150		Distribution		598,965	1.63						
151		Customer Accounting		-	-						
152		Customer Service		621,810	1.69						
153		Sales		3,283	0.01						
154		Total (Excluding A&G)		36,782,622	100.00						
155											

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East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Accumulated Reserves for Depreciation
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total as of 12/31/09 ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		**Intangible Plant**									
3		Organization	LABOR	-	-	-	-	-	-	-	
4		Franchises	LABOR	-							
5		Misc. Intang. Plant	TRANS	(588,159)	-	-	-	(588,159)	-	-	[1]
6		*Subtotal - Intangible Plant*		(588,159)	-	-	-	(588,159)	-	-	Sum(L3 : L5)
7											
8		**Production Plant**									
9		Steam									
10	108	Land & Land Rights	[2]	(2,321,695)	(880,235)	(1,373,536)	(67,924)	-	-	-	
11	108	Struct. & Improve.	[2]	(60,125,374)	(23,030,381)	(35,937,077)	(1,157,916)	-	-	-	
12	108	Boiler Plant Equip.	[2]	(383,317,994)	(145,858,314)	(227,600,294)	(9,859,386)	-	-	-	
13	108	Engines & Gen.	[2]	-							
14	108	Turbogenerator Units	[2]	(67,832,035)	(26,492,538)	(41,339,497)	-	-	-	-	
15	108	Access. Elec. Equip.	[2]	(22,880,952)	(8,926,270)	(13,928,734)	(25,948)	-	-	-	
16	108	Misc. Plant Equipment	[2]	(1,598,502)	(607,826)	(948,464)	(42,212)	-	-	-	
17		Subtotal		(538,076,551)	(205,795,564)	(321,127,602)	(11,153,385)	-	-	-	Sum(L10 : L16)
18		Nuclear									
19	108	Land & Land Rights		-							
20	108	Struct. & Improve.		-							
21	108	Reactor Plant Equip.		-							
22	108	Turbogenerator Units		-							
23	108	Access. Elec. Equip.		-							
24	108	Misc. Plant Equipment		-							
25		Subtotal		-	-	-	-	-	-	-	Sum(L19 : L24)
26		Hydraulic									
27	108	Land & Land Rights		-							
28	108	Struct. & Improve.		-							
29	108	Rsrvr Dams & Strwys		-							
30	108	Wheels Turb. & Gen.		-							
31	108	Accessory Electrical Equip.		-							
32	108	Misc. Plant Equipment		-							
33	108	Rds RR & Bridges		-							
34		Subtotal		-	-	-	-	-	-	-	Sum(L27 : L33)
35		Other									
36	108	Land & Land Rights	PROD_OTH_PLNT	(1,229,975)	(1,229,975)	-	-	-	-	-	
37	108	Struct. & Improve.	PROD_OTH_PLNT	(8,824,666)	(8,824,666)	-	-	-	-	-	
38	108	Prod. & Access.	PROD_OTH_PLNT	(3,713,556)	(3,713,556)	-	-	-	-	-	
39	108	Prime Movers	PROD_OTH_PLNT	(40,137,471)	(40,137,471)	-	-	-	-	-	
40	108	Generators	PROD_OTH_PLNT	(13,425,669)	(13,425,669)	-	-	-	-	-	
41	108	Access. Elec. Equip.	PROD_OTH_PLNT	(4,851,354)	(4,851,354)	-	-	-	-	-	
42	108	Misc. Plant Equip.	PROD_OTH_PLNT	(1,527,450)	(1,527,450)	-	-	-	-	-	
43		Subtotal		(73,710,140)	(73,710,140)	-	-	-	-	-	Sum(L36 : L42)
44		Subtotal--Production		(611,786,692)	(279,505,704)	(321,127,602)	(11,153,385)	-	-	-	L17 + L43

[1] Accumulated reserves for depreciation associated with interconnections with other utilities.
[2] Prorate based on plant investment in each account.

East Kentucky Power Cooperative, Inc.
Functionalization/Classification of Accumulated Reserves for Depreciation
Calendar 2009

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total as of 12/31/09 ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
45											
46		**Transmission**									
47	108	Land & Land Rights	2	(14,087,207.88)	-	-	-	(14,087,208)	-	-	
48	108	Struct. & Improve.	2	-							
49	108	Station Equip.	1	(52,339,960)	(4,291,585)	-	-	(46,165,773)	-	(1,882,601)	
50	108	Towers & Fixtures	2	(1,171,981.43)	-	-	-	(1,171,981)	-	-	
51	108	Poles & Fixtures	2	(39,266,199.29)	-	-	-	(39,266,199)	-	-	
52	108	OH Cond. & Devices	2	(27,881,032.36)	-	-	-	(27,881,032)	-	-	
53	108	UG Conduit	2	-							
54	108	UG Cond. & Devices	2	-							
55	108	Roads & Trails	2	(6,989.13)	-	-	-	(6,989)	-	-	
56		Subtotal - Transmission		(134,753,370)	(4,291,585)	-	-	(128,579,183)	-	(1,882,601)	Sum(L47 : L55)
57											
58		**Distribution**									
59	108	Land & Land Rights	2	(2,134,214.43)	-	-	-	-	(2,134,214)	-	
60	108	Struct. & Improve.	2	-							
61	108	Station Equip.	2	(40,345,627.75)	-	-	-	-	(40,345,628)	-	
62	108	Stor. Battery Equip.	2	-							
63	108	Poles Tower & Fix.	2	-							
64	108	OH Cond. & Devices	2	-							
65	108	UG Conduit	2	-							
66	108	UG Cond. & Devices	2	-							
67	108	Line Transformers	2	(364,816.52)	-	-	-	-	(364,817)	-	
68	108	Services	2	-							
69	108	Meters	2	-							
70	108	Install on Cust. Ld	2	-							
71	108	Leased Ld from Cust.	2	-							
72	108	Street Light & Signal	2	-							
73		Subtotal - Distribution		(42,844,659)	-	-	-	-	(42,844,659)	-	Sum(L59 : L72)
74											
75		Subtotal - Prod. Trans. Dist Plant		(746,540,061)	(283,797,289)	(321,127,602)	(11,153,385)	(128,579,183)	-	(1,882,601)	L44 + L56 + L73
76		**General**									
77	108	Land & Land Rights	2	(591,220.47)	(242,272)	(227,762)	(7,108)	(99,669)	(9,059)	(5,350)	
78	108	Struct. & Improve.	2	(9,995,932.59)	(4,096,170)	(3,850,832)	(120,180)	(1,685,140)	(153,157)	(90,455)	
79	108	Off. Furn. & Equip.	2	(4,472,338.76)	(1,832,691)	(1,722,923)	(53,770)	(753,958)	(68,525)	(40,471)	
80	108	Transp. Equip.	2	(4,935,145.47)	(2,022,342)	(1,901,215)	(59,334)	(831,979)	(75,616)	(44,659)	
81	108	Stores Equip.	2	(103,458.34)	(42,396)	(39,856)	(1,244)	(17,441)	(1,585)	(936)	
82	108	Shop & Garage Equip.	2	(1,087,075.04)	(445,466)	(418,785)	(13,070)	(183,262)	(16,656)	(9,837)	
83	108	Lab Equip.	2	(1,730,372.19)	(709,078)	(666,608)	(20,804)	(291,711)	(26,513)	(15,658)	
84	108	Power Op. Equip.	2	(5,890,558.82)	(2,413,855)	(2,269,278)	(70,821)	(993,045)	(90,255)	(53,305)	
85	108	Communication Equip.	2	(20,383,454.39)	(8,352,806)	(7,852,519)	(245,067)	(3,436,294)	(312,315)	(184,453)	
86	108	Misc. Equip.	2	(825,206.49)	(338,156)	(317,902)	(9,921)	(139,115)	(12,644)	(7,467)	
87	108	Other Tangible Prop.	2	-							
88	108	Subtotal-General Plant		(50,014,763)	(20,495,231)	(19,267,681)	(601,320)	(8,431,615)	(766,325)	(452,592)	Sum(L77 : L87)
89											
90		Grand Total		(839,987,642)	(304,292,520)	(340,395,283)	(11,754,705)	(137,598,957)	(43,610,984)	(2,335,193)	L75 + L88

[1] Depreciation Reserves associated with distribution meters are direct assigned, with the remainder assigned based on plant investment in that account.

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(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total	(f) Production Capacity	(g) Production Energy	(h) Production Steam Direct	(i) Transm.	(j) Distribution Substations	(k) Distribution Meters	(l) Notes
1				($)	($)	($)	($)	($)	($)	($)	
2		Plant in Service		3,083,650,873	1,139,662,678	1,292,023,473	44,774,477	444,061,586	157,719,914	5,408,745	Ex. B, pg. 2
3		Accum. Depr. Reserves		(839,987,642)	(304,292,520)	(340,395,283)	(11,754,705)	(137,598,957)	(43,610,984)	(2,335,193)	Ex. C, pg. 2
4		Net Plant		2,243,663,231	835,370,158	951,628,190	33,019,772	306,462,629	114,108,931	3,073,552	L2 - L3
5	107	Construction Work in Progress									
6	107	Production-Steam	PROD_PEAKER	170,641,685	48,223,340	122,418,345	-	-	-	-	
7	107	Production-Steam Service Related	STEAM_SERV	32,149,860	8,652,905	21,966,009	1,530,946	-	-	-	
8	107	Production-Other	PROD_OTH_PLNT	139,910,500	139,910,500	-	-	-	-	-	
9	107	Transmission	TRANS	29,201,072				29,201,072			
10	107	Distribution Substations	DIST_SUB	6,979,845					6,979,845		
11	107	Ditsribution Meters	DIST_METER	96,876						96,876	
12	107	General Plant	LABOR	3,863,509	1,583,203	1,488,378	46,450	651,320	59,197	34,962	
13	107	Total CWIP		382,843,347	198,369,948	145,872,732	1,577,396	29,852,392	7,039,042	131,838	Sum(L6:L12)
14	108	Retirement Work in Progress	DIRECT	2,687,087	1,421,537	-		1,446,942	(181,392)		
15	108	Retirement Work in Progress	LABOR	18,201	7,458	7,012	219	3,068	279	165	
16		Adjusted Net Plant		2,623,801,290	1,032,311,111	1,097,493,910	34,596,949	334,865,010	121,329,085	3,205,225	L4+L13+L14-L15
17											
18	165	Prepayments	NET_PLNT	1,571,678	585,174	666,612	23,130	214,676	79,933	2,153	
19											
20	151	Fuel Stocks	FUEL_EXP	69,903,296	-	68,199,716	1,703,580	-	-	-	
21											
22		Materials and Supplies									
23	154	Production-Steam	PROD_STM_PLNT	25,053,337	9,582,030	14,951,995	519,312	-	-	-	
24	154	Production-Other	PROD_OTH_PLNT	617,287	617,287	-	-	-	-	-	
25	154	ETS	PROD_CAP	58,916	58,916						
26	154	Transmission	TRANS_PLNT	10,658,752	342,548	-	-	10,203,634	-	112,570	
27	154	Distribution Subtation	DIST_SUB	3,777,628	-	-	-	-	3,777,628	-	
28	154	Distribution Meters	DIST_METER								
29	154	General Plant	LABOR	1,049	430	404	13	177	16	9	
30		Subtotal--M&S		40,166,969	10,601,210	14,952,399	519,324	10,203,811	3,777,644	112,580	Sum(L23 : L29)
31											
32		Cash Working Capital (1/8)									
33		Production Expense									
34		Total		62,143,777	7,434,790	53,316,436	1,108,951	268,442	2,748	12,410	Exhibit A, pg. 2
35		Less: Fuel		37,115,060	-	36,210,546	904,514	-	-	-	Ex. A, pg. 1&2
36		Less: Purch. Power		9,929,559	-	9,929,559	-	-	-	-	Ex. A, pg. 2
37		Net Production		15,099,159	7,434,790	7,176,332	204,437	268,442	2,748	12,410	L34 - L35 - L36
38		Transmission O&M		3,730,511	43,429	-	-	3,622,124	-	64,958	Ex. A, pg. 2
39		Distribution O&M		209,536	-	-	-	-	193,744	15,792	Ex. A, pg. 2
40		Customer Accounts		-	-	-	-	-	-	-	Ex. A, pg. 2
41		Customer Service & Info.		249,456	-	249,456	-	-	-	-	Ex. A, pg. 3
42		Sales		763	-	763	-	-	-	-	Ex. A, pg. 3
43		Administrative & General		3,698,606	1,515,628	1,424,850	44,468	623,520	56,670	33,469	Ex. A, pg. 3
44		Subtotal--CWC		22,988,030	8,993,848	8,851,401	248,905	4,514,086	253,162	126,629	Sum(L37 : L43)
45											
46		Total Rate Base		2,758,431,263	1,052,491,342	1,190,164,038	37,091,889	349,797,583	125,439,824	3,446,586	L16 + L18+L20+ L30+L44
47											
48				2,243,663,231	835,370,158	951,628,190	33,019,772	306,462,629	114,108,931	3,073,552	L4
49			NET_PLNT	1.000000	0.372324	0.424140	0.014717	0.136590	0.050858	0.001370	
50											
51				2,758,431,263	1,052,491,342	1,190,164,038	37,091,889	349,797,583	125,439,824	3,446,586	L46
52			RATE BASE	1.000000	0.381554	0.431464	0.013447	0.126810	0.045475	0.001249	
53											
54			STEAM_SERV	1.000000	0.269143	0.683238	0.047619				Workpaper WP-4

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(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		Power Production									
3		Steam									
4	500	Oper. Super. & Eng.	PROD_CAP	7,594,038 [2]	7,482,541		111,497				1
5	501	Fuel	PROD_ENG	278,856,859		271,620,750	7,236,109				1
6	502	Steam	PROD_CAP	9,135,440	9,005,031		130,409				1
7	503	Steam-Other Sources	PROD_CAP			-					1
8	504	Steam Transferred	PROD_CAP			-					1
9	505	Electric	PROD_CAP	4,949,188 [2]	4,891,224		57,964				1
10	506	Misc. Steam Power	PROD_CAP	24,293,270 [2]	23,884,908		408,362				1
11	507	Rents	PROD_CAP		-						1
12	509	Allowances	PROD_ENG	10,432,273		10,327,853	104,420				1
13	510	Main. Super. & Eng.	PROD_ENG	2,571,560		2,530,152	41,408				1
14	511	Main. Struct.	PROD_CAP	3,021,229	2,973,480		47,749				1
15	512	Main. Boiler Plant	PROD_ENG	31,487,461 [2]		30,816,643	670,818				1
16	513	Main. Electric Plant	PROD_ENG	8,866,053 [2]		8,809,914	56,139				1
17	514	Main. Misc. Plant	PROD_CAP	124,139	123,571		568				1
18											
19		Nuclear									
20	517	Oper. Super. & Eng.									
21	518	Nuclear Fuel									
22	519	Coolants & Water									
23	520	Steam Exp.									
24	521	Steam - Other Sources									
25	522	Steam Transferred									
26	523	Electric									
27	524	Misc. Nuclear Power									
28	525	Rents									
29	528	Main. Super. & Eng.									
30	529	Main. Struct.									
31	530	Main. Reactor Plant									
32	531	Main. Electric Plant									
33	532	Main. Misc. Plant									
34											
35		Hydraulic									
36	535	Oper. Super. & Eng.									
37	536	Water for Power									
38	537	Hydraulic									
39	538	Electric									
40	539	Misc. Hydr. Power									
41	540	Rents									
42	541	Main. Super. & Eng.									
43	542	Main. Struct.									
44	543	Main. Waterways									
45	544	Main. Electric Plant									
46	545	Main. Misc. Hydr. Plant									

[1] Allocate O&M expense for the steam production related expense to Steam Service. See Workpaper WP-4. Assign the remainder in accordance with FERC standard methodology.

[2] Includes annualizing adjustments for 1) Spurlock No. 1 Scrubber, and Spurlock No. 4 which were commercial for only part of 2009. See Workpaper WP-22.

East Kentucky Power Cooperative, Inc.
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(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
47											
48		**Power Production (Con't.)**									
49		**Other**									
50	546	Oper. Super. & Eng.	PROD_CAP	379,440	379,440						1
51	547	Fuel	PROD_ENG	18,063,618		18,063,618					1
52	548	Generation	PROD_CAP	3,174,159	3,174,159						1
53	549	Misc. Other Power	PROD_CAP	885,220	885,220						1
54	550	Rents	PROD_CAP		-						1
55	551	Main. Super. & Eng.	PROD_CAP	27,230	27,230						1
56	552	Main. Struct.	PROD_CAP	138,759	138,759						1
57	553	Main. Gen. & Elec. Plant	PROD_CAP	2,794,902	2,794,902						1
58	554	Main. Misc. Other Power		98,814	98,814						1
59											
60		**Other Power Supply**									
61	555	Purchased Power	PROD_ENG	79,436,469 [2]		79,436,469					
62	556	System Control & Dispatch	[3]	3,643,003	182,150	1,275,051		2,087,190		98,612	
63	557	Other Expenses	DIRECT	6,754,754	3,281,126	3,473,628					4
64	557	Other Expenses	PTD_PLNT	422,340	155,768	177,413	6,162	60,347	21,985	666	4
65											
66		Subtotal - Production		497,150,217	59,478,323	426,531,490	8,871,605	2,147,536	21,985	99,278	Sum(L4 : L64)
67											
68		**Transmission**									
69	560	Oper. Super. & Eng.	TRANS_OM	2,922,646	69,705	-	-	2,748,681	-	104,260	
70	561	Load Dispatching	[5]	2,536,940				2,213,134		323,806	
71	562	Oper. Station	TRANS_STA	2,524,182	164,562	-	-	2,305,541	-	54,079	
72	563	Oper. OH Line	TRANS_LINES	1,690,707	-	-	-	1,690,707	-	-	
73	564	Oper. UG Line	TRANS_LINES		-	-	-	-	-	-	
74	565	Trans of Electricity - Others	TRANS	14,828,464				14,828,464			
75	566	Misc. Transmission Oper.	TRANS	567,938				567,938			
76	567	Rents	TRANS	448,288				448,288			
77	568	Main. Super. & Eng.	TRANS_OM	11,834	282	-	-	11,130	-	422	
78	569	Main. Structures	TRANS					-			
79	570	Main. Station Equipment	TRANS_STA	1,731,481	112,882	-	-	1,581,502	-	37,096	
80	571	Main. OH Lines	TRANS_LINES	2,530,289	-	-	-	2,530,289	-	-	
81	572	Main. UG Lines	TRANS_LINES		-	-	-	-	-	-	
82	573	Main. Misc. Trans. Plant	TRANS	51,317				51,317			
83											
84		Subtotal - Transmission		29,844,086	347,432	-	-	28,976,990	-	519,664	Sum(L69 : L82)

[3] Breakdown provided by EKPC. See Workpapers WP-7 and WP-11.
[4] Assign DLC expenses to PROD_CAP, and expenses related to power supply and ACES brokerage fees to PROD_ENG. See Workpaper WP-18. Assign the remainder of Acct. 557 based on PTD_PLNT.
[5] See Workpaper WP-7 for the metering expense. Assign the remainder to Transmission.

East Kentucky Power Cooperative, Inc.
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(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
85											
86		**Distribution**									
87	580	Oper. Super. & Eng.	DIST_SUB						-		
88	581	Load Dispatching	[6]	161,957					35,623	126,334	
89	582	Station	DIST_SUB	589,810					589,810		
90	583	OH Line	DIST_SUB						-		
91	584	UG Line	DIST_SUB						-		
92	585	Street Light & Signal System	DIST_SUB						-		
93	586	Meters	DIST_SUB						-		
94	587	Customer Installation	DIST_SUB						-		
95	588	Misc. Operations	DIST_SUB						-		
96	589	Rents	DIST_SUB						-		
97	590	Main. Super. & Eng.	DIST_SUB						-		
98	591	Main. Struct.	DIST_SUB						-		
99	592	Main. Station Equipment	DIST_SUB	924,519					924,519		
100	593	Main. OH Lines	DIST_SUB						-		
101	594	Main. UG Lines	DIST_SUB						-		
102	595	Main. Line Transf.	DIST_SUB						-		
103	596	Main. Street Light & Signal	DIST_SUB						-		
104	597	Main. Meters	DIST_SUB						-		
105	598	Misc. Maintenance	DIST_SUB						-		
106											
107		Subtotal - Distribution		1,676,285	-	-	-	-	1,549,951	126,334	Sum(L87 : L105)
108											
109		**Customer Accounts**									
110	901	Supervision	PROD_ENG			-					
111	902	Meter Reading	PROD_ENG			-					
112	903	Cust. Rec. & Coll.	PROD_ENG			-					
113	904	Uncollectible Accts.	PROD_ENG			-					
114	905	Misc. Cust. Accts.	PROD_ENG			-					
115											
116		Subtotal - Cust. Accts.		-	-	-	-	-	-	-	Sum(L110 : L114)
117											
118		**Customer Service & Info.**									
119	907	Supervision	PROD_ENG			-					
120	908	Cust. Assistance	PROD_ENG	1,983,731		1,983,731					
121	909	Advertising	PROD_ENG	11,054		11,054					
122	910	Misc. Serv. & Info.	PROD_ENG	864		864					
123											
124		Subtotal - Cust. Serv. & Info.		1,995,650	-	1,995,650	-	-	-	-	Sum(L109 : L123)
125											
126		**Sales**									
127	911	Supervision	PROD_ENG			-					
128	912	Demo. & Selling	PROD_ENG			-					
129	913	Advertising	PROD_ENG	6,101		6,101					
130	916	Misc. Sales	PROD_ENG			-					
131											
132		Subtotal - Sales		6,101	-	6,101	-	-	-	-	Sum(L127 : L130)

[6] See Workpaper WP-7 for metering expense. Assign the remainder to Distribution Substations.

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East Kentucky Power Cooperative, Inc.
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(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
133											
134		**Administrative & General**									
135	920	Salaries	LABOR	10,362,927	4,246,558	3,992,213	124,592	1,747,008	158,781	93,776	
136	921	Off. Supplies & Exp.	LABOR	4,901,663	2,008,621	1,888,316	58,932	826,335	75,103	44,356	
137	922	Admin. Transferred	LABOR		-	-	-	-	-	-	
138	923	Outside Services	LABOR	4,864,798	1,993,515	1,874,114	58,489	820,120	74,538	44,022	
139	924	Property Insurance	NET_PLNT		-	-	-	-	-	-	
140	925	Injuries & Damages	LABOR	2,005,367	821,767	772,547	24,110	338,070	30,726	18,147	
141	926	Pensions & Benefits	LABOR	1,032,872	423,254	397,903	12,418	174,124	15,826	9,347	
142	927	Franchise Req.	LABOR		-	-	-	-	-	-	
143	928	Reg. Commission	LABOR	1,215,150	497,949	468,124	14,610	204,853	18,619	10,996	
144	929	Duplicate Charges	LABOR	(483,399)	(198,089)	(186,225)	(5,812)	(81,493)	(7,407)	(4,374)	
145	930	Misc. General Expense	LABOR	4,755,366	1,948,671	1,831,957	57,173	801,672	72,862	43,032	
146	931	Rents	LABOR		-	-	-	-	-	-	
147	935	Main. Gen. Plant	LABOR	934,103	382,780	359,854	11,231	157,474	14,312	8,453	
148											
149		Subtotal - Administration & General		29,588,847	12,125,025	11,398,804	355,742	4,988,162	453,360	267,754	Sum(L135 : L147)
150											
151		Subtotal - Operating Expense		560,261,186	71,950,780	439,932,044	9,227,347	36,112,689	2,025,296	1,013,030	L66+L84 + L107 + L116 + L124 + L132 + L149
152											
153		**Depreciation**									
154	405	Intangible	INTG_PLNT	51,882	59	55	2	51,762	2	1	
155	403	Production-Steam	PROD_STM_PLNT	42,483,027	16,248,280	25,354,148	880,599	-	-	-	
156	403	Production-Other	PROD_OTH_PLNT	6,599,313	6,599,313	-	-	-	-	-	
157	403	Transmission	TRANS_PLNT	5,717,499	183,747	-	-	5,473,368	-	60,384	
158	403	Distribution	DIST_PLNT	4,867,035	-	-	-	-	4,867,035	-	
159	403	General	PTD_PLNT	4,061,000	1,664,131	1,564,459	48,825	684,614	62,223	36,749	
160											
161		Subtotal - Depreciation		63,779,756	24,695,531	26,918,662	929,425	6,209,743	4,929,260	97,134	Sum(L154 : L159)
162											
163		**Taxes**									
164	408	Property--Production		-							7
165	408	Property--Transmission		-							7
166	408	Property--Distribution		-							7
167	408	Property--General Plant		-							7
168	408	Payroll & Other	LABOR	800	328	308	10	135	12	7	7
169											
170		Subtotal - Taxes		800	328	308	10	135	12	7	Sum(L164 : L168)
171											
172	431	**Interest - Other**	NET_PLNT	35,781	13,322	15,176	527	4,887	1,820	49	
173											
174		**Other Deductions**									
175	426	EPA Penalties	FUEL_EXP	4,937,772	-	4,817,436	120,336	-	-	-	
176	428	Amort. Debt Exp. & Disc.	RATE_BASE	1,171,644	447,046	505,522	15,755	148,577	53,281	1,464	
177	426	Other	LABOR	1,098,105	449,985	423,034	13,202	185,121	16,825	9,937	
178											
179		Total Expenses		631,285,044	97,556,992	472,612,183	10,306,602	42,661,152	7,026,494	1,121,621	L151+L161 + L170 + L172 + L174
180											

[7] Property tax is allocated back to the functional areas in Accounts 500 to 935.

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(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Total (\$)	(f) Production Capacity (\$)	(g) Production Energy (\$)	(h) Steam Direct (\$)	(i) Transm. (\$)	(j) Distribution Substations (\$)	(k) Distribution Meters (\$)	(l) Notes
181											
182		**Return Requirements**									
183		Rate Base		2,758,431,263	1,052,491,342	1,190,164,038	37,091,889	349,797,583	125,439,824	3,446,586	Exhibit D. L46
184		Rate of Return		5.7708%	5.7708%	5.7708%	5.7708%	5.7708%	5.7708%	5.7708%	L188 / L187
185		Return Requirements		159,182,649	60,736,826	68,681,597	2,140,487	20,186,004	7,238,840	198,894	L183 * L184
186		Interest Expense	RATE_BASE	113,319,764	43,237,645	48,893,409	1,523,781	14,370,117	5,153,223	141,590	
187		Margin Requirements	RATE_BASE	45,862,885	17,499,181	19,788,188	616,706	5,815,888	2,085,617	57,304	TIER = 1.40
188		Total Return Requirements		159,182,649	60,736,826	68,681,597	2,140,487	20,186,004	7,238,840	198,894	L186 + L187
189											
190		**Total Gross Revenue Requirements**		790,467,693	158,293,818	541,293,780	12,447,088	62,847,156	14,265,334	1,320,516	L179 + L185
191											
192		TIER		1.40							
193		Operating TIER		1.33							
194											
195		**Revenue/Non-Operating Income Credits**									
196	447	Sales for Resale--Non-Mem.	As Billed	9,844,534	-	9,844,534					Workpaper WP-9
197	454	Other Electric Revenue	DIRECT	14,544,659	2,611,809	9,104,368	255,336	2,561,129	12,017	-	Workpaper WP-10
198		Interest Income	RATE_BASE	3,615,136	1,379,371	1,559,801	48,612	458,437	164,399	4,517	
199		AFUDC	RATE_BASE	4,883,872	1,863,462	2,107,215	65,672	619,325	222,094	6,102	
200		Cap. Credits & Pat.Dividend	RATE_BASE	264,435	100,896	114,094	3,556	33,533	12,025	330	
201		Other Non Operating Inc.	RATE_BASE	(59,871)	(22,844)	(25,832)	(805)	(7,592)	(2,723)	(75)	
202		Salt River Generation Credit	Direct	(534,105)	(92,830)	(441,275)					
203		Subtotal - Rev. Credits		32,558,660	5,839,864	22,262,906	372,371	3,664,832	407,812	10,875	Sum(L195 : L201)
204											
205		**Net Member Revenue Requirements**		757,909,033	152,453,954	519,030,874	12,074,718	59,182,325	13,857,522	1,309,641	L190 - L203
206											
207		**Average Cost - Control Area**									
208		Total Member-System Billing Units (excludes Inland Steam)									
209		12 CP Demand (MW-mo)			26,904			26,904			Form 12b
210		Energy (MWh)		11,969,336	11,969,336	11,969,336		11,969,336			Form 12b
211		No. Substations							312		
212		Average Cost Total Member Systems									
213		Demand (\$/kW/mo)			5.67			2.20			
214		Energy (\$/MWh)		63.32	12.74	43.36		4.94			
215		Per Substation (\$/Sub/mo)							3,701	350	
216											
217		**Allocation Factors Based on Revenue Requirements**									
218		Fuel Expense		296,920,476	-	289,684,367	7,236,109	-	-	-	
219			FUEL_EXP	1.000000	0.000000	0.975629	0.024371	0.000000	0.000000	0.000000	
220											
221		Transmission O&M		11,632,854	277,444	-	-	10,940,428	-	414,982	Sum(L70:L73) + L75 +
222			TRANS_OM	1.000000	0.023850	0.000000	0.000000	0.940477	0.000000	0.035673	Sum(L78:L82)
223											
224	s	The targeted TIER is designed to match Member Revenue Requirements to Member Revenue Under Present Rates.									
225		Member Revenue Under Present Rates		757,909,033							
226		Other Operating Revenue		23,855,088							L196 + L197
227		Non Operating Income		8,703,572							Sum(L198 : L201)
228		Total Income		790,467,693							Sum(L225 : L227)
229		Less: Operating Expenses		631,285,044							L179
230		Net Revenue		159,182,649							L228 - L229
231		Interest Expense		113,319,764							L186
232		Implied TIER		1.40							L230 / L231

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OWEN ELECTRIC COOPERATIVE
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SUPPLEMENTAL RESPONSE IN REPLY TO THE ATTORNEY GENERAL'S MOTION TO COMPEL REQUEST

Confirm that without decoupling, EKPC, as Owen's primary generation source, has the ability to sell conserved power on the wholesale unregulated market in excess of both the wholesale rates EKPC charges to Owen, and the retail regulated rates Owen charges to its ratepayers.

Response:

Owen states that the answer to this question is answered in the response to Question 31 a., as listed in Owen's response to the Attorney General's Initial Data Request. In the interest of clarity, however, the response is: Whether EKPC can sell and fully recover its imbedded power costs depends upon the market conditions at that time.

a. Question:

Confirm that when Owen's ratepayers conserve energy, EKPC is able to sell that conserved power on the wholesale market, thereby reducing Owen's proportionate costs.

a. Response:

Whether EKPC can sell and fully recover its imbedded power cost depends upon the market conditions at that time. The reduction in Owen's cost is in wholesale power cost, all distribution costs remain the same.

b. Question:

Confirm that from a general perspective, the more power Owen sells, the more its costs will increase.

b. Response:

The more power Owen sells, the more its wholesale power costs increase. All distribution costs remain the same.

OWEN ELECTRIC COOPERATIVE
CASE NO. 2011-00037
SUPPLEMENTAL RESPONSE IN REPLY TO THE ATTORNEY GENERAL'S MOTION TO COMPEL REQUEST

Question:

Confirm that EKPC system-wide experienced a record decline in consumption during 2009.

Response:

As stated in Owen's response to Question 32 a. of the Attorney General's Initial Data Request, EKPC's sales did decrease in calendar year 2009. Owen is not aware whether this reduction constituted a record decline in consumption.

a. Question:

Confirm further that Owen's use of a 2009 test year in the instant proceeding to establish average use per customer will lead to customers paying for that historic decline.

a. Response:

EKPC's sales did decrease in calendar year 2009. Owen disagrees with the statement that establishing average use per customer will lead to customers paying for a decline. We have based this application on the matching of revenue and usage.

OWEN ELECTRIC COOPERATIVE
CASE NO. 2011-00037
SUPPLEMENTAL RESPONSE IN REPLY TO THE ATTORNEY GENERAL'S MOTION TO COMPEL REQUEST

Reference the Stallons testimony, p. 2, wherein he states the purpose of the instant filing is to align the member charge with the company's fixed costs over a five-year period. Provide any and all documentation to support Owen's forecasted fixed costs over the next five years, including any and all assumptions underlying such forecasts.

Response:

Owen states that the response to this question was answered in the response to Question 60 a. and b. to the Attorney General's Initial Data Request. In the interest of clarity, however, the answer to the question is: The application did not utilize a forecasted test period, and all of its consumer related costs discussed in this rate application were calculated as a part of the Cost of Service Study prepared for this application and are based on the actual costs for our calendar year test period ending December 31, 2009. As no forecasted test period was utilized, there are no forecasted fixed costs, no assumptions underlying such forecasts, and no documentation exists.

a. Question:

State to what extent, if any, the company's forecasted fixed costs are dependent upon the 2008 load forecast.

a. Response:

None. The application did not utilize a forecasted test period.

b. Question:

State to what extent, if any, the company's forecasted fixed costs in the instant case relies upon the most recent load forecast.

b. Response:

Owen's consumer related costs discussed in this rate application were calculated as a part of the Cost of Service Study done for this application and are based on the actual costs for our calendar year test period ending December 31, 2009.

OWEN ELECTRIC COOPERATIVE
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SUPPLEMENTAL RESPONSE IN REPLY TO THE ATTORNEY GENERAL'S MOTION TO COMPEL REQUEST

Reference the Stallons testimony, p.5, question no. 18, wherein Mr. Stallons defines the "throughput incentive" as an incentive "to increase fixed cost[s] and margin recovery." Does Mr. Stallons acknowledge that Owen is likewise under an incentive to maximize its fixed costs? If he does not so admit, explain why not in complete detail.

Response:

Owen states that the response to this question was answered in the responses to Question 23 a. and 67 a. to the Attorney General's Initial Data Request. In the interest of clarity, however, the answer to the question is: Owen does not admit that it is incentivized to increase its fixed costs. Owen believes that the cooperative form of governance provides adequate incentive for Owen to effectively and efficiently manage its fixed costs.

a. Question:

Is the concept of providing the lowest cost energy possible to its members not enough incentive for Owen to reduce its fixed costs? If not, why not? Please explain in complete detail.

a. Response:

The cooperative form of governance provides adequate incentive for Owen to manage its distribution costs. Refer to the response to Question 23(a).

b. Question:

Please explain the nature of the legal duty Owen believes it owes to its members.

b. Response:

The company owes its member owners the duty to operate efficiently, effectively and in accordance with cooperative principles and state and federal laws".

OWEN ELECTRIC COOPERATIVE
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SUPPLEMENTAL RESPONSE IN REPLY TO THE ATTORNEY GENERAL'S MOTION TO COMPEL REQUEST

c. Question:

If Owen institutes DSM programs and attempts to recover any sales lost as a result of the "energy innovations" Mr. Stallons describes in his answer to this question, would that not eliminate the purported"disincentive" described therein? If not, why not? Describe in complete detail.

c. Response:

The existing rate structure provides Owen an incentive to increase energy sales and a corresponding disincentive to decrease energy sales. As a consequence Owen, in this case, is proposing to move to a cost of service rate structure where the throughput incentive is lessened. For more information please refer to Owen's response to Question 8 in Commission Staff's First Data Request.

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SUPPLMENTAL RESPONSE IN REPLY TO THE ATTORNEY GENERAL'S MOTION TO COMPEL REQUEST

Question:

Reference the Stallons testimony, p.6, question no. 19, wherein he states that raising the customer charge is the "simplest way for a rural electric cooperative to mitigate the throughput incentive." Would doing so also be the most effective and efficient way? If so, why? If not, why not? Explain in complete detail.

Response:

Owen states that the responses to questions 68, 68a, and 68b were answered in the response to Question 68 b. to the Attorney General's Initial Data Request. In the interest of clarity, however, the answer to the question is: Owen believes increasing the customer charge and lowering the energy charge in a revenue neutral manner is the simplest, most effective, and efficient way to mitigate the throughput incentive. For a more thorough analysis of same please refer to Owen's response to Question 8 in Commission Staff's First Data Request.

a. Question:

If Owen also instituted DSM programs designed to recover its lost sales resulting from the implementation of energy efficiency measures, would Mr. Stallons continue to believe that raising the customer charge remains the "simplest way" to mitigate the throughput incentive?

a. Response:

Yes, please refer to the answer to question 68 above.

b. Question:

If Owen also instituted DSM programs designed to recover its lost sales resulting from the implementation of energy efficiency measures, would Mr. Stallons believe that raising the customer charge would be the most effective and efficient means of mitigating the throughput incentive? If not, explain why not in complete detail.

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SUPPLEMENTAL RESPONSE IN REPLY TO THE ATTORNEY GENERAL'S MOTION TO COMPEL REQUEST

b. Response:

Owen has no desire to recover lost sales revenue in a DSM surcharge format. Please refer to Owen's response to Question 8 in Commission Staff's First Data Request.