DORSEY, KING, GRAY, NORMENT & HOPGOOD
ATTORNEYS-AT-LAW
318 SECOND STREET
HENDERSON, KENTUCKY 42420

JOHN DORSEY (1920-1986)
FRANK N. KING, JR.
STEPHEN D. GRAY
WILLIAM B. NORMENT, JR.
J. CHRISTOPHER HOPGOOD
S. MADISON GRAY

TELEPHONE
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April 7, 2011

FEDERAL EXPRESS

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40601

RECEIVED
APR 08 2011
PUBLIC SERVICE
COMMISSION

Re: Kenergy Corp.
Case No. 2011-00035

Dear Mr. Derouen:

Enclosed for filing please find Kenergy's Responses to Second Data Requests (original plus 10 copies) in the above referenced matter.

Your assistance in this matter is appreciated.

Very truly yours,

DORSEY, KING, GRAY, NORMENT & HOPGOOD

By

J. Christopher Hopgood
Attorney for Kenergy Corp.

JCH/cds
Encls.
COPY/w/encls. Office of Attorney General, Utility and Rate Intervention Division
Steve Thompson, Kenergy Corp.
KIUC

CASE NO. 2011-00035

VERIFICATION

I verify, state and affirm that the data request responses filed with this verification and for which I am listed as a witness are true and correct to the best of my knowledge, information and belief formed after a reasonable inquiry.

Sanford Novick

Sanford Novick, President & CEO

STATE OF KENTUCKY

COUNTY OF: DAVIESS

The foregoing was signed, acknowledged and sworn to before me by Sanford Novick, this 6th day of April, 2011.

My commission expires October 16, 2012

Benita M. Martin

Notary Public, KY. State at Large

(seal)

CASE NO. 2011-00035

VERIFICATION

I verify, state and affirm that the data request responses filed with this verification and for which I am listed as a witness are true and correct to the best of my knowledge, information and belief formed after a reasonable inquiry.

Steve Thompson

Steve Thompson, Vice President - Finance

STATE OF KENTUCKY

COUNTY OF: DAVIESS

The foregoing was signed, acknowledged and sworn to before me by Steve Thompson, this 6th day of April, 2011.

My commission expires October 16, 2012

Benita M. Martin

Notary Public, KY. State at Large

(seal)

CASE NO. 2011-00035

VERIFICATION

I verify, state and affirm that the data request responses filed with this verification and for which I am listed as a witness are true and correct to the best of my knowledge, information and belief formed after a reasonable inquiry.

David Hamilton

David Hamilton, Director of Member Services

STATE OF KENTUCKY

COUNTY OF: DAVIESS

The foregoing was signed, acknowledged and sworn to before me by David Hamilton, this 6th day of April, 2011.

My commission expires October 16, 2012

Benita M. Martin

Notary Public, KY. State at Large

(seal)

CASE NO. 2011-00035

VERIFICATION

I verify, state and affirm that the data request responses filed with this verification and for which I am listed as a witness are true and correct to the best of my knowledge, information and belief formed after a reasonable inquiry.

John E Newland

John Newland, Vice President - Engineering

STATE OF KENTUCKY

COUNTY OF: DAVIESS

The foregoing was signed, acknowledged and sworn to before me by John Newland, this 6th day of April, 2011.

My commission expires October 16, 2012

Benita M. Martin

Notary Public, KY. State at Large

(seal)

CASE NO. 2011-00035

VERIFICATION

I verify, state and affirm that the data request responses filed with this verification and for which I am listed as a witness are true and correct to the best of my knowledge, information and belief formed after a reasonable inquiry.

Keith Ellis

Keith Ellis, Vice President - Human Resources

STATE OF KENTUCKY

COUNTY OF: DAVIESS

The foregoing was signed, acknowledged and sworn to before me by Keith Ellis, this 6th day of April, 2011.

My commission expires October 16, 2012

Benita M. Martin

Notary Public, KY. State at Large

(seal)

CASE NO. 2011-00035

VERIFICATION

I verify, state and affirm that the data request responses filed with this verification and for which I am listed as a witness are true and correct to the best of my knowledge, information and belief formed after a reasonable inquiry.

Jack D. Gaines, JDG Consulting

STATE OF GEORGIA

COUNTY OF: Fulton

The foregoing was signed, acknowledged and sworn to before me by Jack D. Gaines, this 4th day of April, 2011.

My commission expires July 2, 2012

Notary Public

(seal)

FRANCESCA CUNEO
NOTARY PUBLIC
MY COMMISSION EXPIRES JULY 02, 2012
FULTON COUNTY, GEORGIA

CASE NO. 2011-00035

VERIFICATION

I verify, state and affirm that the data request responses filed with this verification and for which am listed as a witness are true and correct to the best of my knowledge, information and belief after a reasonable inquiry.

Robert Welsh
Robert Welsh
President, Welsh Group, LLC

COMMONWEATH OF VIRGINIA
COUNTY OF: FAIRFAX

The foregoing was signed, acknowledged and sworn to before me by Robert N. Welsh, this 4th day of April, 2011.

My commission expires Jan. 31. 2014

SHAHEEN KAUSAR
Notary Public
Commonwealth of Virginia
318113
My Commission Expires Jan 31, 2014

Shaheen Kausar
Notary Public

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 1) Refer to Exhibit 3B of the Application.

a. Refer to First Revised Sheet No. 15. State whether Kenergy included the footnote at the bottom of this tariff page solely to provide explanation to assist in the processing of the Application or if Kenergy intends for the footnote to be part of its tariff.

Response) Upon further review, the new light shown on the proposed tariff Sheet No. 15 was not left off the current tariff sheet 15 approved in Case No. 2008-00323. The 20,000 lumen - 200 watt and 27,000 lumen - 250 watt were combined at a rate of $9.69 prior to Case No. 2008-00323. They were also combined in Case No. 2008-00323 and a proposed rate of $9.98 was approved. Due to a billing error, four lights per month have continued to be billed at $9.69 vs. $9.98. A revised Sheet No. 15 is attached as Item 1a, page 2 of 3. Also attached as Item 1a, page 3 of 3 is a revised Exhibit 10a, page 6, reflecting the correct proposed rate of $10.96 vs. $10.66. The proposed revenue increases $13.00.

Witness) Steve Thompson

Kenergy

Henderson, Kentucky

FOR ALL TERRITORY SERVED
Community, Town or City
PSC NO. 2
First Revised SHEET NO. 15
CANCELLING PSC NO. 2
Original SHEET NO. 15

CLASSIFICATION OF SERVICE
Schedule 15 – Private Outdoor Lighting

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this schedule is offered, under the conditions set out hereinafter, for lighting applications on private property such as, but not limited to, residential, commercial and industrial plant site or parking lot, other commercial area lighting, etc. to customers now receiving electric service from Kenergy at the same location. Service will be provided under written contract signed by customer prior to service commencing, when facilities are required other than fixture(s).

Standard (Served Overhead)

	Type Light	Watts	Approx. Lumens	Avg. Monthly Energy (KWH)	(per lamp per month) Rates
T	***Not Available for New Installations after April 1, 2011 - will be replaced with the nearest equivalent lumen fixture***				
I	Mercury Vapor	175	7,000	70	$ 7.87
	Mercury Vapor	250	12,000	97	$ 9.27
	Mercury Vapor	400	20,000	155	$10.91
T	***Available for New Installations after April 1, 2011:***				
I	High Pressure Sodium	100	9,500	44	$ 7.65
I	High Pressure Sodium	200/ 250	20,000/27,000	101	$10.96
I	High Pressure Sodium--Flood Light	400	61,000	159	$12.47
I	Metal Halide	100	9,000	42	$ 7.19
I	Metal Halide	400	24,000	156	$14.75

In the event existing facilities cannot be utilized, customer will be required to make an advance contribution equal to the estimated cost of labor and materials in excess of the cost to install the lighting unit on existing facilities.

Customer shall be responsible for losses due to vandalism.

DATE OF ISSUE March 1, 2011
Month / Date / Year

DATE EFFECTIVE April 1, 2011
Month / Date / Year

ISSUED BY
(Signature of Officer)

TITLE President and CEO

BY AUTHORITY OF ORDER OF THE PUBLIC SERVICE COMMISSION
IN CASE NO. 2011-00035 DATED

KENERGY CORP.
2011 RATE APPLICATION
PRIVATE AND OUTDOOR LIGHTING CONSUMPTION ANALYSIS

	(a) DESCRIPTION	(b) Number billed	(c) Monthly Assigned kwh/light	(d) kwh booked	(e) Present rate	(f) wholesale Proposed rate	(g) Present Revenue	(h) Wholesale Proposed Revenue	Distribution proposed rate	Distribution Proposed revenue
1	**Private Outdoor Lighting**									
2	**Tariff sheet 15**									
3	**Standard(served overhead)**									
4	7000 LUMEN-175W-MERCURY VAPOR	133,868	70	9,370,760	$ 7.16	$7.80	$ 958,495	$ 1,044,170	$ 7.87	$ 1,053,541
5	12000 LUMEN-250W-MERCURY VAPOR	2,417	97	234,449	$ 8.45	$9.19	$ 20,424	$ 22,212	$ 9.27	$ 22,406
6	20000 LUMEN-400W-MERCURY VAPOR	6,744	155	1,045,320	$ 9.98	$10.82	$ 67,305	$ 72,970	$ 10.91	$ 73,577
7	9500 LUMEN-100W-HPS	3,195	44	140,580	$ 6.95	$7.59	$ 22,205	$ 24,250	$ 7.65	$ 24,442
8	27000 LUMEN-250W-HPS	1,804	101	182,204	$ 9.98	$10.87	$ 18,004	$ 19,609	$ 10.96	$ 19,772
9	61000 LUMEN-400W-HPS-FLOOD LGT	266	159	42,294	$11.39	$12.36	$ 3,030	$ 3,288	$ 12.47	$ 3,317
10	9000 LUMEN-100W METAL HA	5,021	42	210,882	$ 6.53	$7.13	$ 32,787	$ 35,800	$ 7.19	$ 36,101
11	24000 LUMEN-400W METAL H	139	156	21,684	$13.45	$14.63	$ 1,870	$ 2,034	$ 14.75	$ 2,050
12	20000 LUMEN-200W-HPS	45	75	3,375	$ 9.69	$10.87	$ 436	$ 489	$ 10.96	$ 493
13	**Tariff sheet 15A**				(1)					
14	**Commercial and Industrial Lighting**									
15	**Flood Lighting Fixture**									
16	28000 LUMEN HPS-250W-FLOOD LGT	978	103	100,734	$ 8.99	$9.78	$ 8,792	$ 9,565	$ 9.86	$ 9,643
17	61000 LUMEN-400W-HPS-FLOOD LGT	1,420	160	227,200	$11.39	$12.36	$ 16,174	$ 17,551	$ 12.47	$ 17,707
18	140000 LUM-1000W-HPS-FLOOD LGT	132	377	49,764	$26.17	$28.40	$ 3,454	$ 3,749	$ 28.64	$ 3,780
19	19500 LUMEN-250W-MH-FLOOD LGT	211	98	20,678	$ 8.69	$9.45	$ 1,834	$ 1,994	$ 9.53	$ 2,011
20	32000 LUMEN-400W-MH-FLOOD LGT	1,233	156	192,348	$11.36	$12.34	$ 14,007	$ 15,215	$ 12.44	$ 15,339
21	107000 LUM-1000W-MH-FLOOD LGT	438	373	163,374	$26.17	$28.40	$ 11,462	$ 12,439	$ 28.64	$ 12,544
22	**Contemporary(Shoebox)**									
23	28000 LUMEN-250W-HPS SHOEBOX	36	103	3,708	$10.27	$11.19	$ 370	$ 403	$ 11.29	$ 406
24	61000 LUMEN-400W-HPS SHOEBOX	168	160	26,880	$12.75	$13.85	$ 2,142	$ 2,327	$ 13.97	$ 2,347
25	107000 LUMENS-100W-MH SHOEBOX	432	377	162,864	$26.17	$28.40	$ 11,305	$ 12,269	$ 28.64	$ 12,372
26	19500 LUMEN-250W-MH SHOEBOX	30	98	2,940	$ 9.91	$10.79	$ 297	$ 324	$ 10.88	$ 326
27	32000 LUMENS-400W-MH SHOEBOX	1,188	156	185,328	$12.50	$13.59	$ 14,850	$ 16,145	$ 13.71	$ 16,287
28	107000 LUMENS-1000W-MH SHOEBOX	-	373	-	$26.17	$28.40	$ -	$ -	$ 28.64	$ -
29	**Decorative Lighting**									
30	9000 LUMEN MH ACORN GLOBE	11	42	462	$ 9.67	$10.58	$ 106	$ 116	$ 10.67	$ 117
31	16600 LUM-175W-MH ACORN GLOBE	284	71	20,164	$11.74	$12.83	$ 3,334	$ 3,644	$ 12.94	$ 3,675
32	9000 LUM-175W-MH ROUND GLOBE	-	42	-	$ 9.48	$10.37	$ -	$ -	$ 10.46	$ -
33	16600 LUM-175W-MH ROUND GLOBE	88	71	6,248	$10.84	$11.85	$ 954	$ 1,043	$ 11.95	$ 1,052
34	16600 LUM-175W-MH LANTERN GLOBE	-	71	-	$10.96	$11.98	$ -	$ -	$ 12.08	$ -
35	28000 LUM - HPS ACORN GLOBE	32	42	1,344	$10.95	$11.99	$ 350	$ 384	$ 12.09	$ 387
36	**Tariff sheet 15B**									
37	**Pedestal Mounted Pole**									
38	STEEL 25 FT PEDESTAL MT POLE	384			$ 6.35	$6.97	$ 2,438	$ 2,676	$ 7.03	$ 2,700
39	STEEL 30 FT PEDESTAL MT POLE	1,164			$ 7.15	$7.85	$ 8,323	$ 9,137	$ 7.92	$ 9,219
40	STEEL 39 FT PEDESTAL MT POLE	198			$12.02	$13.20	$ 2,380	$ 2,614	$ 13.31	$ 2,635
41	WOOD 30 FT DIRECT BURIAL POLE	514			$ 3.98	$4.37	$ 2,046	$ 2,246	$ 4.41	$ 2,267
42	ALUMINUM 28 FT DIRECT BURIAL	57			$ 8.18	$8.98	$ 466	$ 512	$ 9.06	$ 516
43	FLUTED FIBERGLASS 15 FT POLE	255			$ 8.74	$9.60	$ 2,229	$ 2,448	$ 9.68	$ 2,468
44	FLUTED ALUMINUM 14FT POLE	104			$ 9.60	$10.54	$ 998	$ 1,096	$ 10.63	$ 1,106
45	**Street Lighting Service**									
46	**Tariff sheet 16**									
47	7000 LUMEN-175W-MERCURY VAPOR	4,662	70	326,340	$ 7.16	$7.80	$ 33,380	$ 36,364	$ 7.87	$ 36,690
48	20000 LUMEN-400W-MERCURY VAPOR	2,036	155	315,580	$10.02	$10.87	$ 20,401	$ 22,131	$ 10.96	$ 22,315
49	9500 LUMEN-100W-HPS STREET LGT	7,301	43	313,943	$ 6.95	$7.59	$ 50,742	$ 55,415	$ 7.65	$ 55,853
50	27000 LUMEN-250W-HPS ST LIGHT	654	85	55,590	$10.10	$11.01	$ 6,605	$ 7,201	$ 11.10	$ 7,259
51	9000 LUMEN-100W METAL HA	3	42	126	$ 6.53	$7.13	$ 20	$ 21	$ 7.19	$ 22
52	24000 LUMEN-400W METAL H	24	156	3,744	$13.24	$14.40	$ 318	$ 346	$ 14.52	$ 348
53	**Tariff sheet 16A**									
54	**Underground service with non-std. pole**									
55	UG NON-STD POLE-GOVT & DISTRICT	6,340			$ 5.12	$5.62	$ 32,461	$ 35,631	$ 5.67	$ 35,948
56	**Overhead service to street lighting districts**									
57	OH FAC-STREET LIGHT DISTRICT	132			$ 2.13	$2.34	$ 281	$ 309	$ 2.36	$ 312
58	**Decorative Underground service**									
59	6300 LUMEN-DECOR-70W-HPS ACORN	4,340	30	130,200	$ 9.83	$10.77	$ 42,662	$ 46,742	$ 10.86	$ 47,132
60	6300 LUM DECOR-70W-HPS LANTERN	1,845	30	55,350	$ 9.83	$10.77	$ 18,136	$ 19,871	$ 10.86	$ 20,037
61	12600 LUM HPS-70W-2 DECOR FIX	360	60	21,600	$17.36	$19.02	$ 6,250	$ 6,847	$ 19.18	$ 6,905
62	28000 LUM - HPS ACORN GL 14 FT POLI	127	43	5,461	$18.98	$20.81	$ 2,410	$ 2,643	$ 20.99	$ 2,666
63	**Special street lighting districts**									
64	BASKETT STREET LIGHTING	868	23	19,964	$ 2.49	$2.71	$ 2,161	$ 2,352	$ 2.73	$ 2,370
65	MEADOW HILL STREET LIGHTING	360	23	8,280	$ 2.25	$2.45	$ 810	$ 882	$ 2.47	$ 889
66	SPOTTSVILLE STREET LIGHTING	835	23	19,205	$ 2.83	$3.09	$ 2,363	$ 2,580	$ 3.12	$ 2,605
67										
68										
69				13,690,967			$1,451,868	$ 1,582,053		$ 1,595,954
70		Rounding difference		-1,104			$ 31	$ 31		$ -
71		Per books kwh		13,689,863	Per books revenue		$ 1,451,899	$ 1,582,083		$ 1,595,954
72					sum of unwind factors		-			
73					Per books revenue		$ 1,451,899			
74	Wholesale factor sum of .002 effective 7/01/10 adjusted for line losses			0.00208728	times	13,689,863	28,575	27,328		27,328
75	Wholesale Non-Fac PPA of $(0.000963) less base rate roll in			-0.00009102	Normalized revenue		$ 1,480,474			
76	of .000876 adjusted for normalized test year kwh sales.				Proposed revenue			$ 1,609,412		$ 1,623,283
77	(1) should have been billed $9.98.						increase	$ 128,938	increase	$ 13,871

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 1) **b.** Refer to First Revised Sheet No. 15A through Second Revised Sheet No. 16B. On each of these pages, Kenergy has added the language "Not Available for New Installations after April 1, 2011." Explain why this language was added.

Response) In an effort to reduce the number of fixtures and poles to be inventoried and maintained by Kenergy, we will no longer lease these poles and fixtures after April 1, 2011. Kenergy will, however, continue to maintain any poles or fixtures leased to members prior to April 1, 2011.

Witness) David Hamilton

KENERGY CORP.
RESPONSE TO THE COMMISSION'S SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 1) **c.** Refer to First Revised Sheet No. 16. The "Availability of Service" section refers to a service agreement for the subdivisions of Baskett, Meadow Hills, and Spottsville. Provide a copy of the agreement

Response) These lights were installed in the early 1970's. A copy of one of the agreements is shown on page 2 of Item 1c.

Witness) Steve Thompson

FS-2808-4 (1.50) OK 9-13-73

9-76-50

APPLICATION FOR SECURITY LIGHT SERVICE

HENDERSON-UNION R. E. C. C.

I, ______________________________, hereby petition to the Henderson-Union Rural Electric Cooperative Corporation for street light service in the area of Meadow Hill Subdivision, Henderson County, and do hereby agree that an amount not to exceed three dollars $2.00 (~~$3.00~~) per month may be added to my light bill. This agreement may be terminated by either party giving to the other sixty (60) days notice in writing.

The Cooperative will agree to furnish 10 lights, install, and maintain, street light fixtures with 189 watt bulbs, at locations suitable for such installations, under their regular S. L. schedule.

Approved

J. R. Hardin, Manager
Henderson-Union R. E. C. C.

B. R.

9-20-73 dk

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 1) **d.** Refer to First Revised Sheet No. 23D. In the middle of the page, relating to the KWH adder, did Kenergy intend to reference 3.5476 cents, rather than 3.46 cents?

Response) Yes, 3.5476 cents should have been shown.

Witness) Steve Thompson

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 1 **e.** Refer to Second Revised Sheet No. 32, the "Special Meter Reading Charge" section. Explain the reason for the text change from three months to six months.

Response) Kenergy decided to wait six months before sending a service technician to obtain the meter reading to lessen the workload requirements and charges to the customer.

Witness) Steve Thompson

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 1 **f.** Refer to Original Sheet No. 33B and First Revised Sheet No. 36B. Excluding differences in dollar amounts, explain the differences in the calculation of the facilities charge between these two pages.

Response) There is only one methodology difference. First Revised Sheet No. 35B includes a "Replacement Cost Factor" on line 14 that is not part of the formula Original Sheet No. 33B. The purpose of this factor is to add a revenue component to recover replacement cost based on the probability of equipment failure before the end of the useful life as reflected by the depreciation rate. The only other difference is that lines 28 and 29 on Original Sheet No. 33B were a breakout of line 13. That breakout is not shown on First revised Sheet 35B. The comparable amount is the "Capital Recovery Factor" on line 30.

Witness) Jack Gaines

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 1 **g.** Refer to First Revised Sheet No. 76E. Kenergy is proposing a text change to allow for electronic notification to cable television operators for abandonment of facilities. State how Kenergy will retain proof of any electronic notification.

Response) The request anticipates making use of available technology and better accommodation for all parties involved for notice of any type, including abandonment. Kenergy will continue to retain all pertinent correspondence.

Witness) John Newland

Item 1 **h.** Refer to Original Sheet No. 76 (Exhibit A), pages 1 and 2, and First Revised Sheet No. 76 (Exhibit A), pages 1 and 2, specifically the sections containing the calculation of the weighted average cost of poles and anchors.

(1) Page 1 of the tariff sheets shows that the cost for 35' - 40' poles increased $2,709,494, from $25,722,873 on December 31, 2007 to $28,432,367 on June 30, 2010. During this same period, the number of poles increased from 71,524 to 71,965, an increase of 441. Dividing the increase in cost of $2,709,494 by the increase in poles of 441 produces an average cost of $6,144 per pole. Is it correct that Kenergy has paid an average of $6,144 for each new 35' - 40' pole purchased since December 31, 2007? Explain.

(2) Part 1 of the tariff sheets shows that the cost for 40' - 45' poles increased $2,734,995 from $22,827,781 on December 31, 2007 to $25,562,776 on June 30, 2010. During this same period, the number of poles increased from 50,135 to 51,720, an increase of 1,585. Dividing the increase in cost of $2,734,995 by the increase in poles of 1,585 produces an average cost of $1,725 per pole. Is it correct that Kenergy has paid an average of $1,725 for each new 40' - 45' pole purchased since December 31, 2007? Explain.

(3) Page 2 of the tariff sheets shows that the cost for anchors increased $2,996,036, from $14,797,194 on December 31, 2007 to $17,793,230 on June 30, 2010. During this same period, the number of anchors increased from 101,155 to 102,513, an increase of 1,358. Dividing the increase in cost of $2,996,036 by the increase in anchors of 1,358 produces an average cost of $2,206 per anchor. Is it correct that Kenergy has paid an average of $2,206 for each new anchor purchased since December 31, 2007? Explain.

Response h.) **(1)** No. The number of poles added was 5,402 at a cost of $3,495,295, or an average of $647. The number of poles retired was 4,961, with the original cost of $785,801, or an average of $158 (first in - first out basis). The net increase in the number of poles was 441 (5,402 - 4,961).

Response h.) **(2)** No. The number of poles added was 5,128 at a cost of $3,576,288, or an average of $697. The number of poles retired was 3,543, with the original cost of $668,817, or an average of $189 (first in - first out basis). The net increase in the number of poles was 1,585 (5,128 - 3,543).

Response h.) **(3)** No. The number of anchors added was 11,280 at a cost of $3,536,079, or an average of $313. The number of anchors retired was 9,922, with the original cost of $454,791, or an average of $46 (first in - first out basis). The net increase in the number of anchors was 1,358 (11,280 - 9,922).

Witness) Steve Thompson

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 1 **i.** Refer to First Revised Sheet No. 76 (Exhibit A), pages 1 to 3. Provide revised pages 1 to 3 using the rate of return requested in this case.

Response) Item 1i, pages 2 - 4 of 4 contains the above referenced information.

Witness) Steve Thompson

CLASSIFICATION OF SERVICE

Schedule 76 – Cable Television Attachment Tariff

I CALCULATION OF ANNUAL POLE ATTACHMENT CHARGE

1. Annual Attachment Charge – Two-Party Pole

Annual Charge = [weighted avg. cost /1 x .85 /2 – n/a /3] x annual carrying charge /4 x .1224 /5

Annual Charge = $395.09 x .85 x 15.12% x .1224

Annual Charge = $6.22

2. Annual Attachment Charge – Three-Party Pole

Annual Charge = [weighted avg. cost /1 x .85 /2 – n/a /3] x annual carrying charge /4 x .0759 /5

Annual Fixed = $494.25 x .85 x 15.12% x .0759

Annual Charge = $4.82

/1 Weighted Average Cost for Poles Determined as follows:

35'-40' Poles = installed plant cost at 6/30/10 of $28,432,367 ÷ 71,965 poles; or an average cost of $395.09 per pole

40'-45' Poles = installed plant cost at 6/30/10 of $25,562,776 ÷ 51,720 poles; or an average cost of $494.25 per pole.

/2 Reduction factor for lesser appurtenances included in pole accounts per Page 8 of PSC Order in Case No. 251.

/3 Ground wire cost is not included in pole cost records, therefore, subject reduction is not applicable.

/4 See Sheet 76, Exhibit A, page 3 of 3.

/5 Usable space factor per Page 13 of PSC Order in Case No. 251.

FOR ALL TERRITORY SERVED
Community, Town or City
PSC NO. 2

First Revised SHEET NO. 76 (Exh. A)
(Page 2 of 3)

CANCELLING PSC NO. 2

Original SHEET NO. 76 (Exh. A)
(Page 2 of 3)

Kenergy

Henderson, Kentucky

CLASSIFICATION OF SERVICE

Schedule 76 – Cable Television Attachment Tariff

I CALCULATION OF ANNUAL ANCHOR ATTACHMENT CHARGE

1. Annual Attachment Charge – Two-Party Anchor

$$\text{Annual Charge} = \frac{[\text{weighted average cost}^{/1} \times \text{annual carrying charge}^{/2}]}{2}$$

$$\text{Annual Charge} = \frac{\$173.57 \times 15.12\%}{2}$$

Annual Charge = $13.12

2. Annual Attachment Charge – Three-Party Anchor

$$\text{Annual Charge} = \frac{[\text{weighted average cost}^{/1} \times \text{annual carrying charge}^{/2}]}{3}$$

$$\text{Annual Charge} = \frac{\$173.57 \times 15.12\%}{3}$$

Annual Charge = $8.75

/1 Weighted Average Cost for Anchors Determined as follows:

Installed plant cost of all anchors $17,793,230 ÷ 102,513 anchors; or an average cost of $173.57 per anchor as of 6/30/10.

/2 See Sheet 76, Exhibit A, page 3 of 3.

DATE OF ISSUE March 1, 2011
Month / Date / Year

DATE EFFECTIVE April 1, 2011
Month / Date / Year

ISSUED BY
(Signature of Officer)

TITLE President and CEO

BY AUTHORITY OF ORDER OF THE PUBLIC SERVICE COMMISSION
IN CASE NO. 2011-00035 DATED

Kenergy	FOR ALL TERRITORY SERVED Community, Town or City
	PSC NO. 2
	First Revised SHEET NO. 76 (Exh. A) (Page 3 of 3)
Henderson, Kentucky	CANCELLING PSC NO. 2
	Original SHEET NO. 76 (Exh. A) (Page 3 of 3)

CLASSIFICATION OF SERVICE

Schedule 76 – Cable Television Attachment Tariff

PSC ADMINISTRATIVE CASE NO. 251

		Percent	Proforma Margins	Proforma Interest
1.	Cost of Money:			
	Rate of Return as proposed Case No. 2011-00035	6.65%	(6,087,662 + 6,087,662)	
	Times Net-to-Gross Ratio	.73*	$183,181,674	= 6.65%
I	Adjusted Rate of Return	4.85%	Net Investment Rate Base	

2. Proforma Operations and Maintenance Expense per Exhibit 5, Page 1, Lines 23 & 24, Col. h:

I $\frac{\$13,162,562}{\$244,223,858} \times 100 =$ 5.39%

3. Proforma Depreciation Expense per Exhibit 5, Page 1, Line 29, Col. h:

I $\frac{\$8,874,587}{\$244,223,858} \times 100 =$ 3.63%

4. Proforma General Administrative Expense per Exhibit 5, Page 1, Line 28, Col. h:

R $\frac{\$3,060,642}{\$244,223,858} \times 100 =$ 1.25%

I Annual Carrying Charges 15.12%

* Net Plant Investment $178,613,465 = 73%

I Gross Plant Investment $244,223,858 (June 30, 2010)

DATE OF ISSUE March 1, 2011
Month / Date / Year

DATE EFFECTIVE April 1, 2011
Month / Date / Year

ISSUED BY ____________________
(Signature of Officer)

TITLE President and CEO

BY AUTHORITY OF ORDER OF THE PUBLIC SERVICE COMMISSION
IN CASE NO. 2011-00035 DATED

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 1 **j.** Refer to First Revised Sheet No. 137. Provide the reasons for the proposed text changes to this page.

Response) The textual change is clarification only.

Witness) John Newland

Item 1 **k.** Refer to First Revised Sheet No. 139A. Provide the supporting calculations for the following:

(1) Underground cost per foot of $12.37.

(2) Overhead cost per foot of $13.28.

(3) Differential (trenching by contractor) of $8 per foot.

(4) Differential (trenching by Kenergy) of $12 per foot.

Response) Item 1k, page 2 of 2, contains the above referenced information.

Witness) John Newland

OVERHEAD vs UNDERGROUND COMPARISON
2010-2011

Work Order Type	# W.O.'s	Total Distance	Total Cost	Avg Cost Per Ft.
Overhead	272	52,012	$690,896	$13.28
Underground	293	57,276	$708,347	$12.37
Kenergy Trenching	7	1,268	$31,044	$24.48

Underground extensions cost less than overhead extensions, on average; therefore there will be no differential charge for underground to permanent residences.

If underground is requested and customer can not complete trenching and conduit installation, Kenergy will provide subject to availability.

Installation is through a contractor retained by Kenergy at a negotiated average fee of $8/foot or by Kenergy at $12/foot, plus the actual cost of conduit in either case.

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 1 l. Refer to Original Sheet No. 153 and First Revised Sheet No. 153. Explain why Kenergy is proposing to delete language stating that there will be no meter test fee if the meter has not been tested in eight years.

Response) Kenergy moved to statistical meter testing (see PSC Case No. 2010-00034), which could allow single phase class 200 meters to be in service indefinitely before a test is required. Prior to statistical testing, Kenergy used an 8-year periodic testing plan. The new language simply allows Kenergy to charge for a request test at any point during the life of a meter.

Witness) Sanford Novick

Item 2) Refer to Exhibit 4 of the Application.

a. The present rate for the 20,000 Lumen-200W-HPS is shown on page 2 and $9.69. This is identified in the proposed tariffs as a light that was inadvertently omitted in Kenergy's most recent rate case. Provide cost justification for the current rate of $9.69.

b. Refer to page 4. The Non-Fuel Adjustment Charge Purchase Power Adjustment is shown as -$.001005024. Provide the supporting calculation for this amount.

Response) a) Refer to the response to Item 1a.

b) From Exhibit 10A, page 14, column K, line 7, the $1,146,244 Non-FAC PPA Rider amount was divided by normalized KWH of 1,140,513,641 from Exhibit 10A, page 1, column f, line 37.

Witness) Steve Thompson

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 3) Refer to Exhibit 5 of the Application, page 1.

a. Provide the supporting calculations for the following adjustments to normalize purchase power costs (column C) for provide their location in the Application:

(1) Non-Direct Served - Base Rate of ($634,289).

(2) Direct Served (excluding smelters) - Base Rate of $246,676.

(3) Smelters - Base Rate of $1,755,058.

b. Provide Exhibit 5 electronically with all formulas intact and unprotected.

c. Provide the supporting calculations for the amounts entered on Exhibit 5, page 4, line 15, or provide their location in the Application.

Response **a)** (1) Exhibit 10a, page 14, line 32

(2) Exhibit 10a, page 12, line 13 of col. (i) minus line 10 of col. (i) minus line 13 of col. (e)

(3) Exhibit 10a, page 10, the sum of lines 2, 10 and 11 of col. (h) minus the sum of lines 2, 10 and 11 of col. (e)

b) Exhibit 5 is attached in an electronic file with all formulas intact and unprotected.

c) See Exhibit 10a, page 14

Witness) Jack Gaines

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 4) Refer to the table starting at the bottom of page 11 and continuing on page 12 of the Direct Testimony of Jack D. Gaines ("Gaines Testimony") which presents rates of return for the non-direct served classes at present rates. The rates of return for the Three Phase 0 - 1,000 KW and Three Phase - Over 1,000 KW are shown as 17.83 percent and 12.45 percent, respectively. Given that the average return for all the classes presented is 4.95 percent, explain why these two classes should receive any allocation of the proposed increase.

Response) Kenergy is proposing a gradual move in the direction of more cost based rates consistent with its approach in past cases as approved by the Commission. In keeping with this approach, the non-power costs portion of the increase to the Three Phase classes (1.0% and 1.4%, respectively) is less than half the 3.0% system average. As explained in testimony by witness Gaines, "Although the rates of return from each class have increased, the classes have each moved closer to the system average and parity as measured by comparing the relative rates of return under present and proposed rates."

Witness) Jack Gaines

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 5) Page 13, starting at line 2, the Gaines Testimony, refers to a $10,037 increase in the Class C facilities charge. Should this refer to the increases as $10,327?

Response) Yes, the testimony should say $10,327.

Witness) Jack Gaines

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 6) Refer to pages 15 and 16 of the Gaines Testimony in which he refers to "facilities" charges. Are the "facilities" charges referred to identified as customer charges in Kenergy's tariff?

Response) Yes, the term "facilities charge" as referenced means "customer charges".

Witness) Jack Gaines

Item 7) Refer to the Gaines Testimony, page 15 at lines 16 to 20, which states, "[b]y comparison to the proposed Facilities Charges of $12.00 and $16.00…" Confirm that these amounts refer to the proposed Residential Facilities Charge and the proposed Non-Residential Single Phase Facilities Charge, respectively. Further confirm that these amounts should be $13.00 and $17.00, respectively.

Response) Yes, the amounts on line 17 should be $13.00 and $17.00, respectively.

Witness) Jack Gaines

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 8) Refer to page 16 of the Gaines Testimony and Exhibit 16, page 8. The Gaines Testimony states that Kenergy is proposing to increase the customer charge from $575 to $750 for the Three Phase - Over 1,000 KW customers. Provide the reason for the increase given that Exhibit 16, page 8, shows the consumer-related costs, including margins, to service a customer in this class to $121.52.

Response) Refer to the response to Item 9.

Witness) Jack Gaines

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 9) Refer to page 16 of the Gaines Testimony at lines 3 to 7. Kenergy proposes to increase the monthly Facilities Charge for the Three Phase - Over 1,000 KW Tariff from $575 to $750. Mr. Gaines states that the proposed increase in the Facilities Charge will have "relatively little bill impact" on customers in the Three Phase - Over 1,000 KW Tariff.

a. Quantify this impact based on the average monthly bill for a customer in the Three Phase - Over 1,000 KW Tariff.

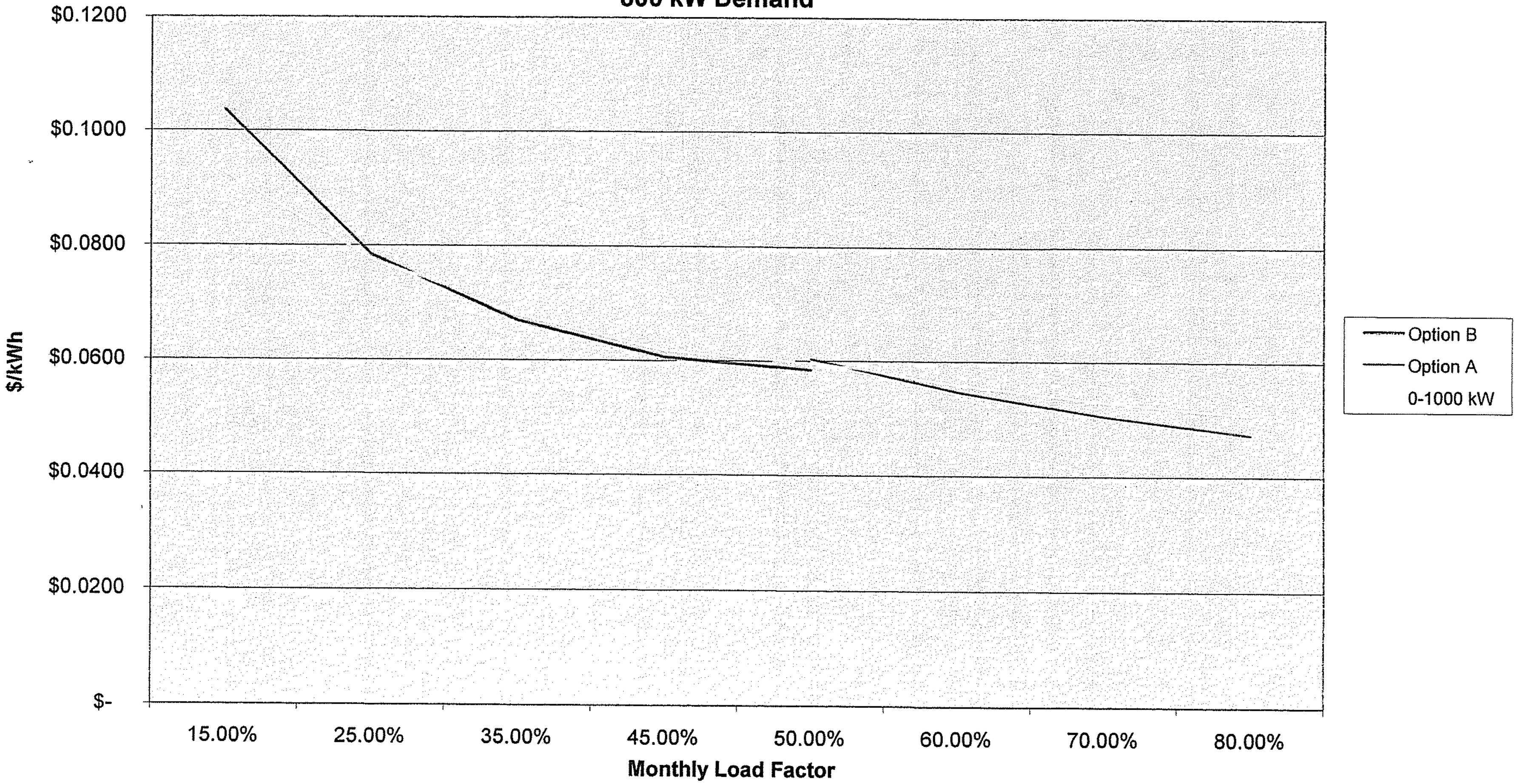
b. The proposed increase in the Facilities Charge for the Three Phase - Over 1,000 KW Tariff is also to assist in differentiating that tariff from the Three Phase 0 - 1,000 KW Tariff. Given that the current monthly Facilities Charges for the Three Phase - Over 1,000 KW and the Three Phase 0 - 1,000 KW Tariffs are $30 and $575, respectively, explain how the increase in the proposed Facilities Charge for the Three Phase - Over 1,000 KW Tariff would help to differentiate that tariff from the Three Phase 0 - 1,000 KW Tariff.

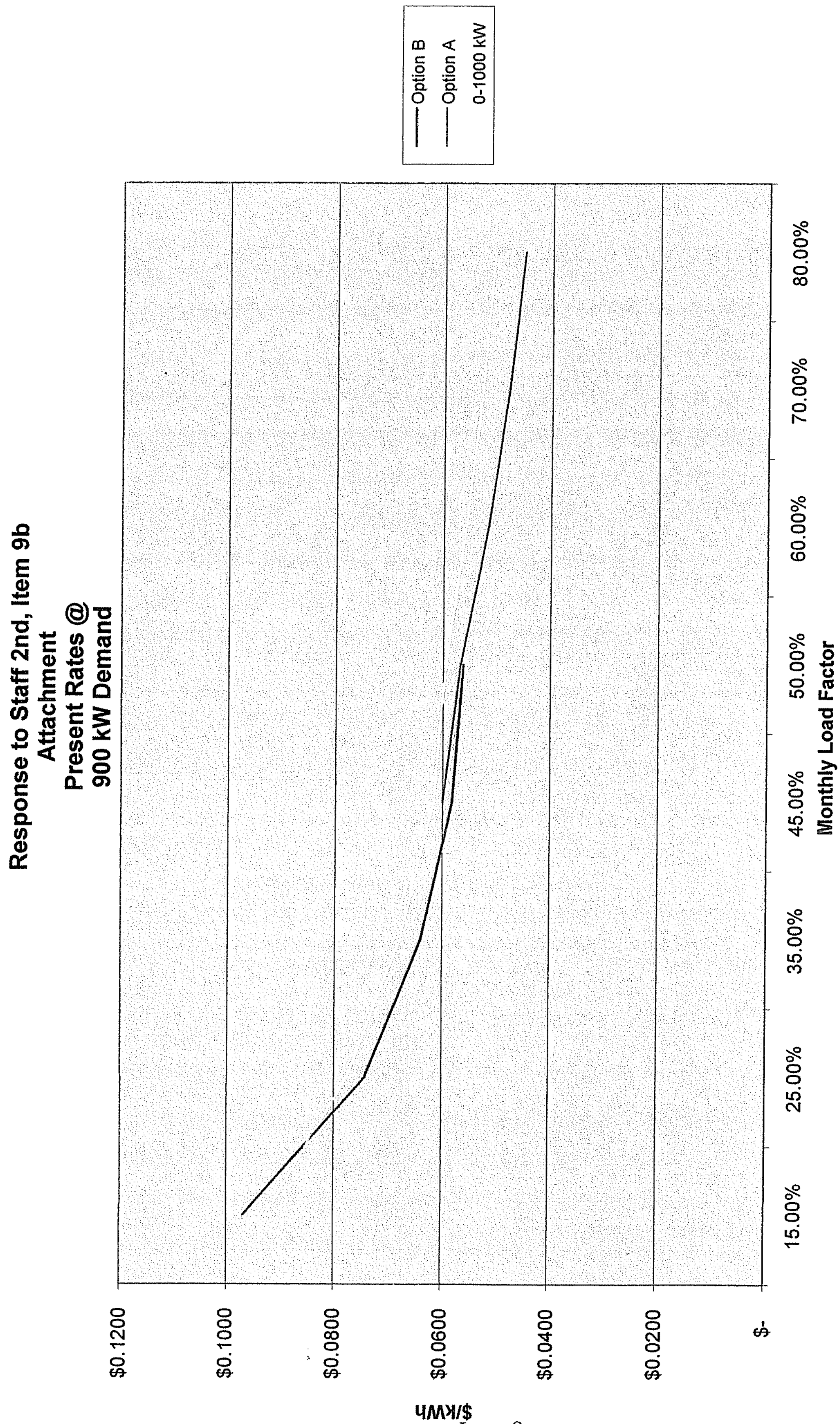
Response a-b) The minimum billing demand in the Three Phase - Over 1,000 KW Tariff is 1,001 KW. This translates into a minimum monthly demand charge of $8,650 (present) and $9,500 (proposed under Option A, and $4,800 (present) and $5,350 (proposed) under Option B. Thus, taken alone, the $225 increase in the customer charge has at most a 2.4% minimum bill impact under Option A and 4.2% minimum bill impact under Option B. This assumes zero usage. The practical bill impacts are much less significant. On average, the revenue increase from the customer charge is 0.7% of the total class present revenue. In this case, the primary purpose of the customer charge is to help provide separation between the Over 1,000 KW Three Phase Tariff and the Under 1,001 KW Three

Phase Tariff. The intent is to make the Over 1,000 KW Tariff unattractive to under 1,001 KW customers while making the Over 1,000 KW Tariff more cost effective for over 1,000 KW loads. Adding $225 to the customer charge improves the separation as it functions integrally with all of the rate components. See the attached graphs.

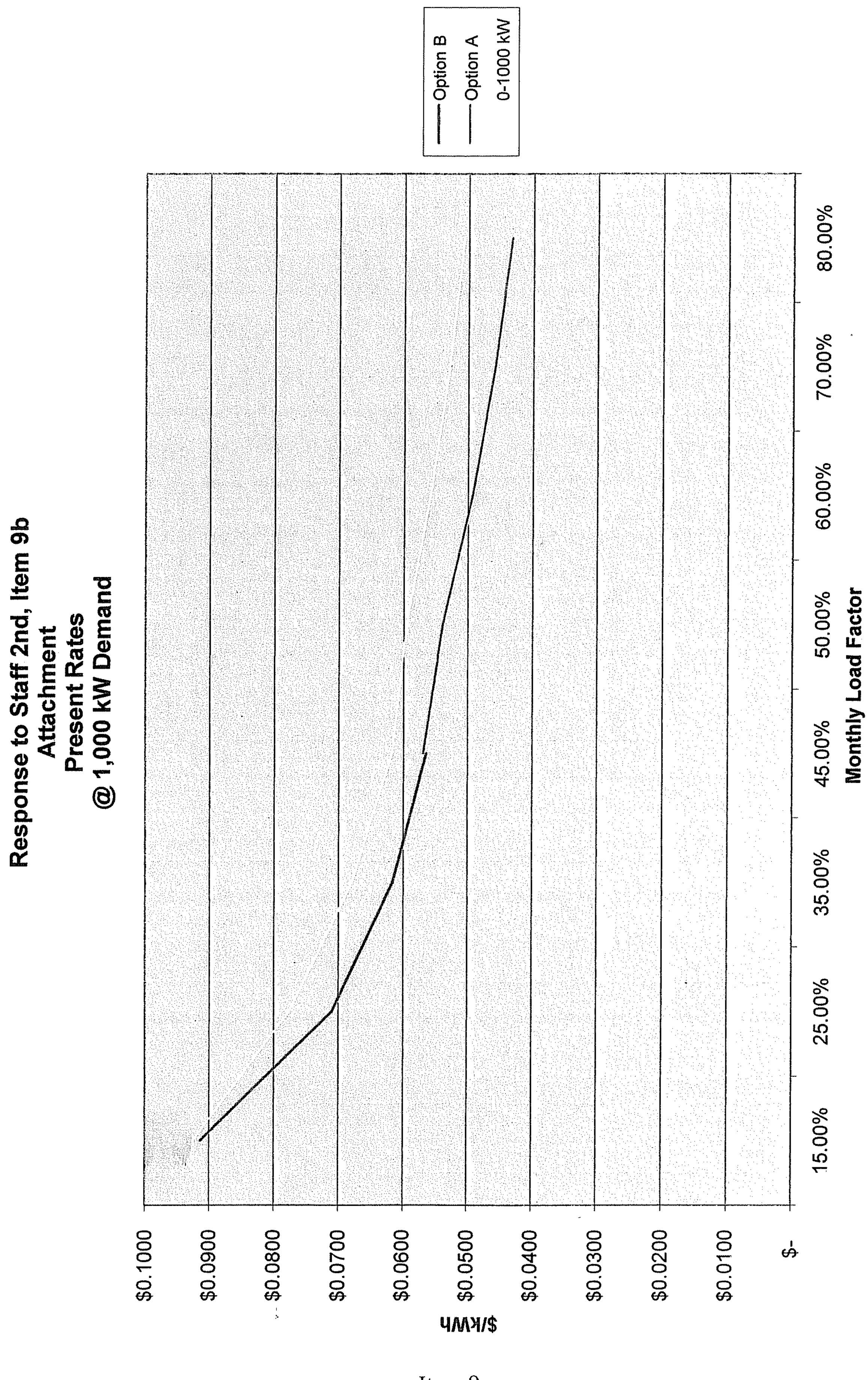
Witness) Jack Gaines

Response to Staff 2nd, Item 9b
Attachment
Present Rates @
800 kW Demand



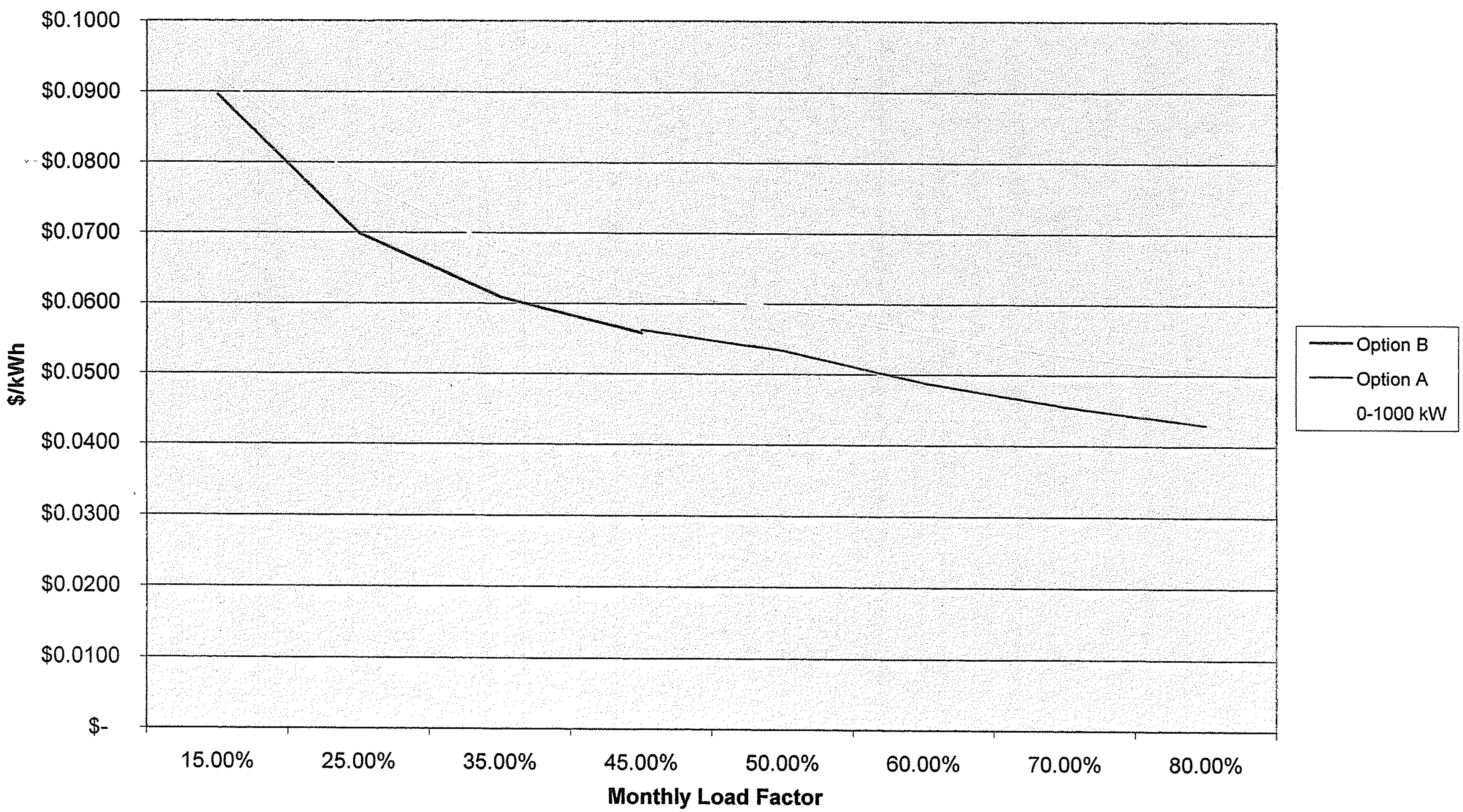


Response to Staff 2nd, Item 9b
Attachment
Present Rates @
900 kW Demand
Option B
Option A
0-1000 kW
$0.1200
$0.1000
$0.0800
$0.0600
$0.0400
$0.0200
$-
$/kWh
15.00%
25.00%
35.00%
45.00%
50.00%
60.00%
70.00%
80.00%
Monthly Load Factor

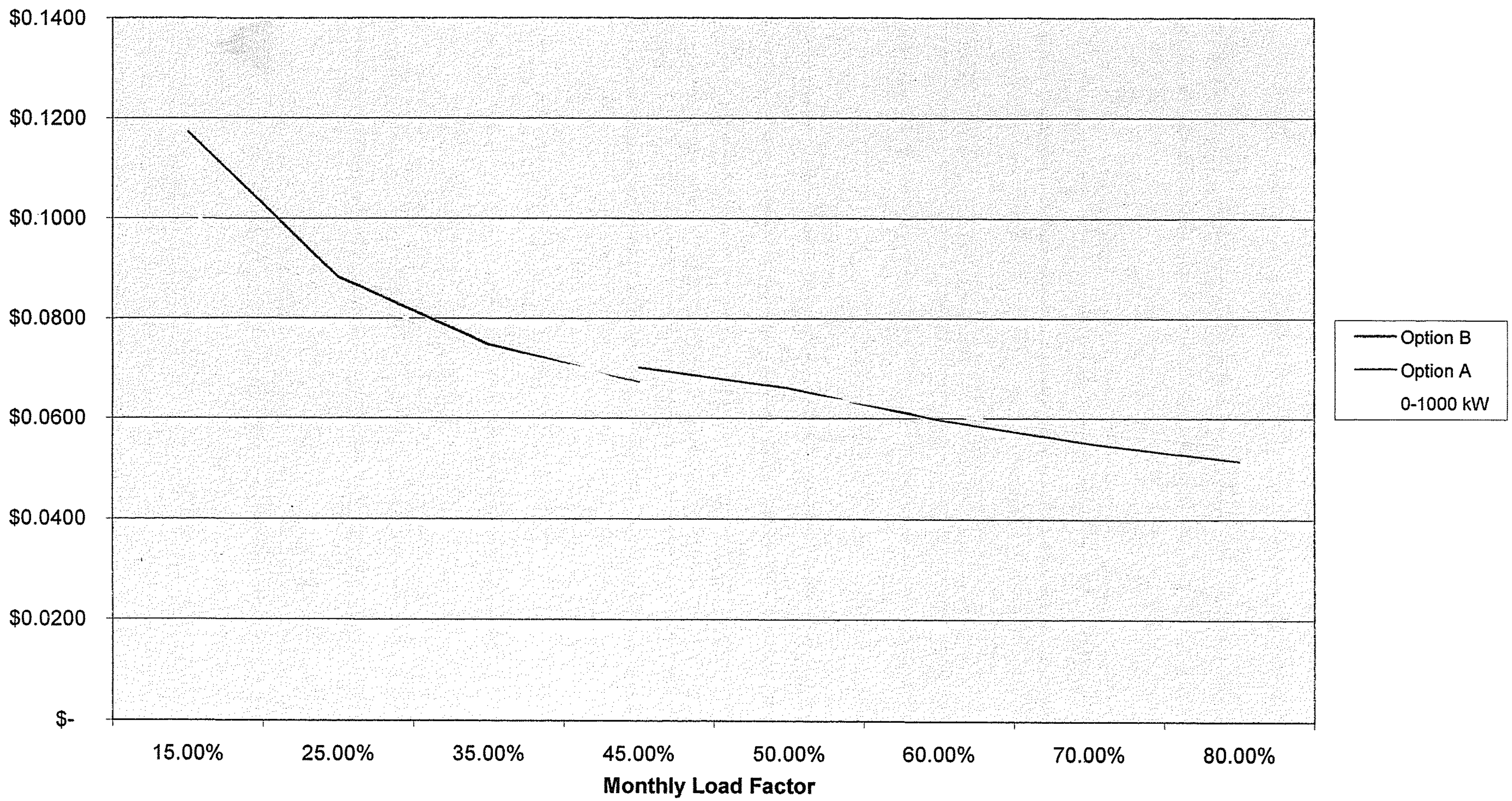


Response to Staff 2nd, Item 9b
Attachment
Present Rates
@ 1,000 kW Demand
Option B
Option A
0-1000 kW
$/kWh
$0.1000
$0.0900
$0.0800
$0.0700
$0.0600
$0.0500
$0.0400
$0.0300
$0.0200
$0.0100
$-
15.00%
25.00%
35.00%
45.00%
50.00%
60.00%
70.00%
80.00%
Monthly Load Factor

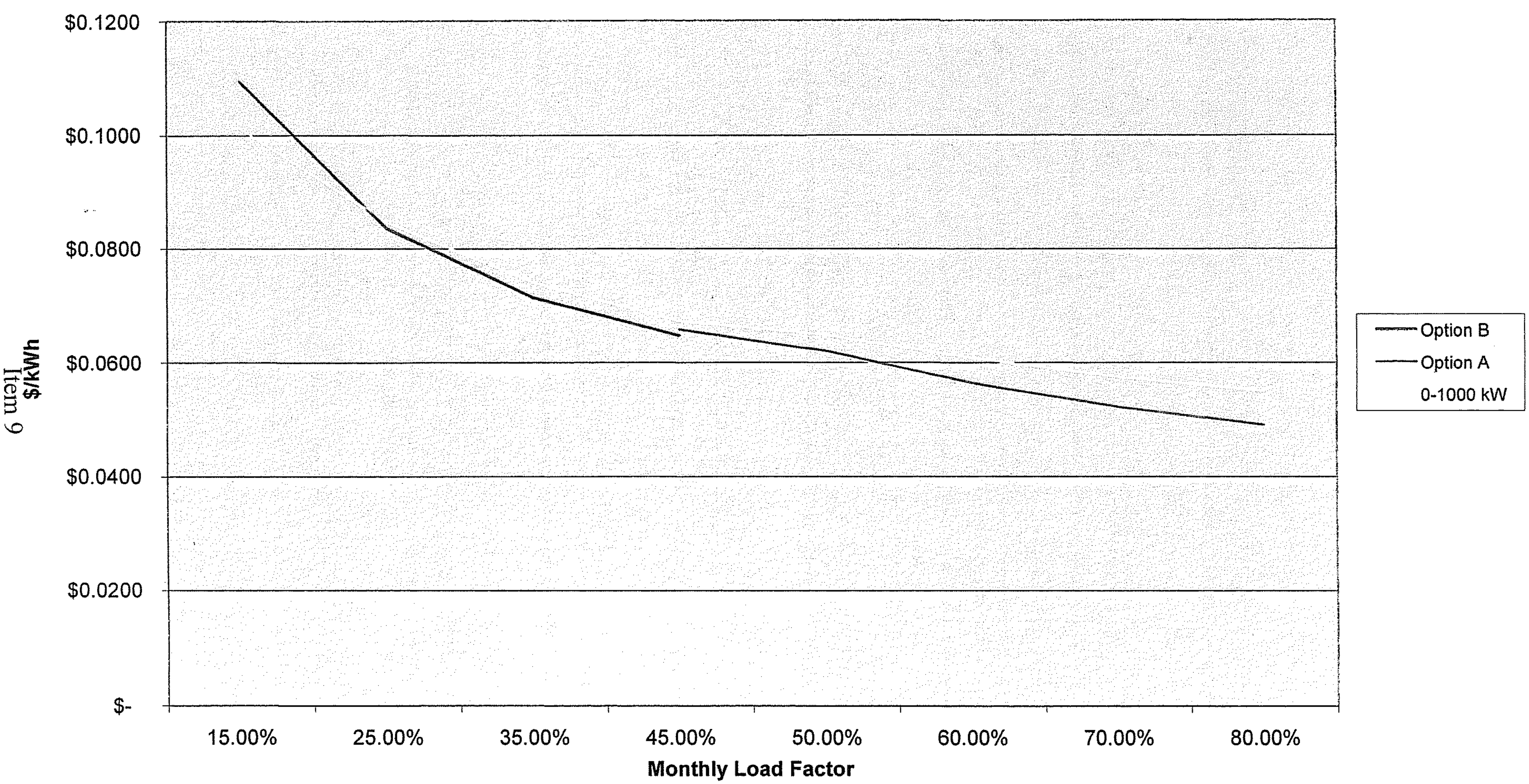
Response to Staff 2nd, Item 9b
Attachment
Present Rates
@ 1,500 kW Demand



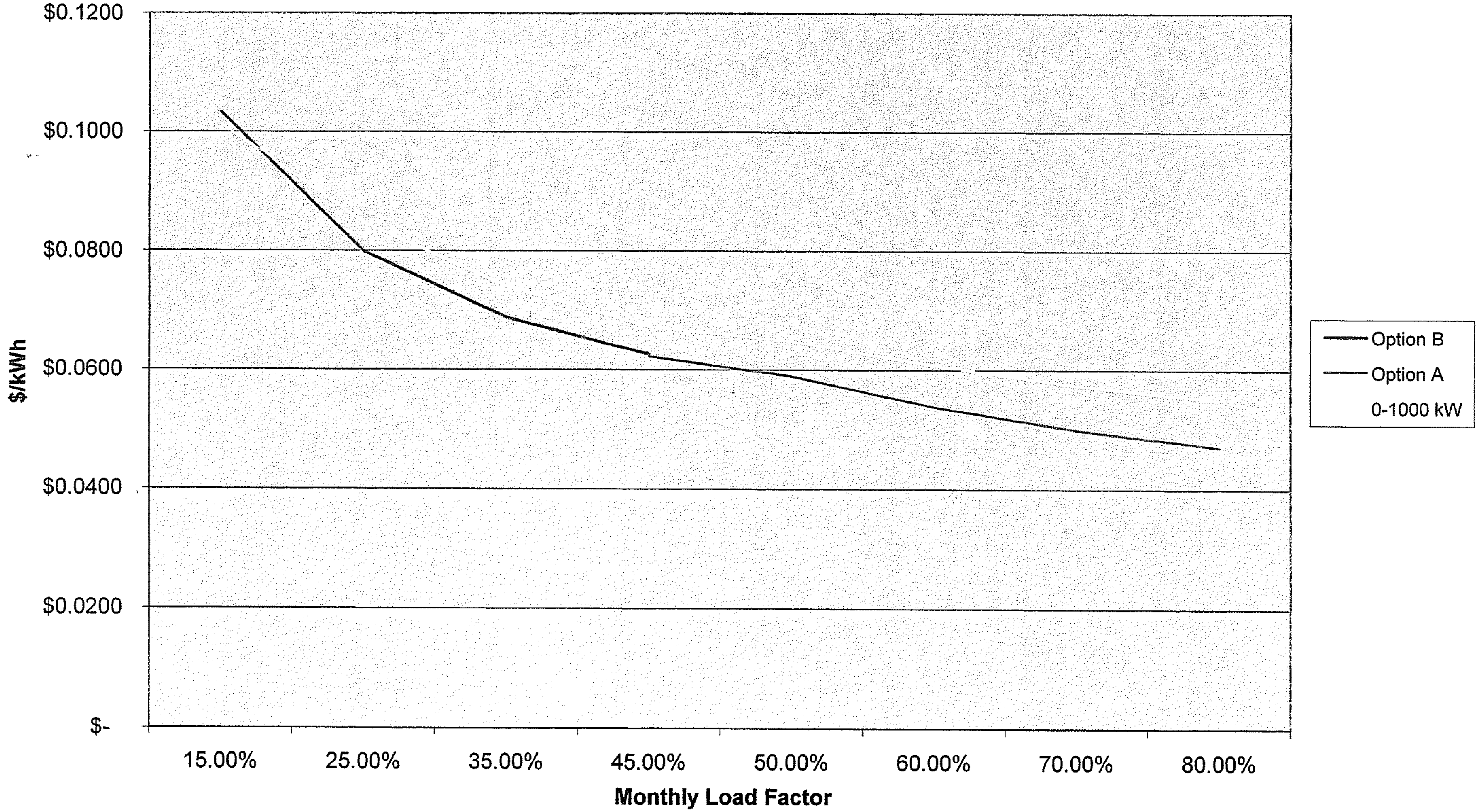
Response to Staff 2nd, Item 9b
Attachment
Proposed Rates @
800 kW Demand



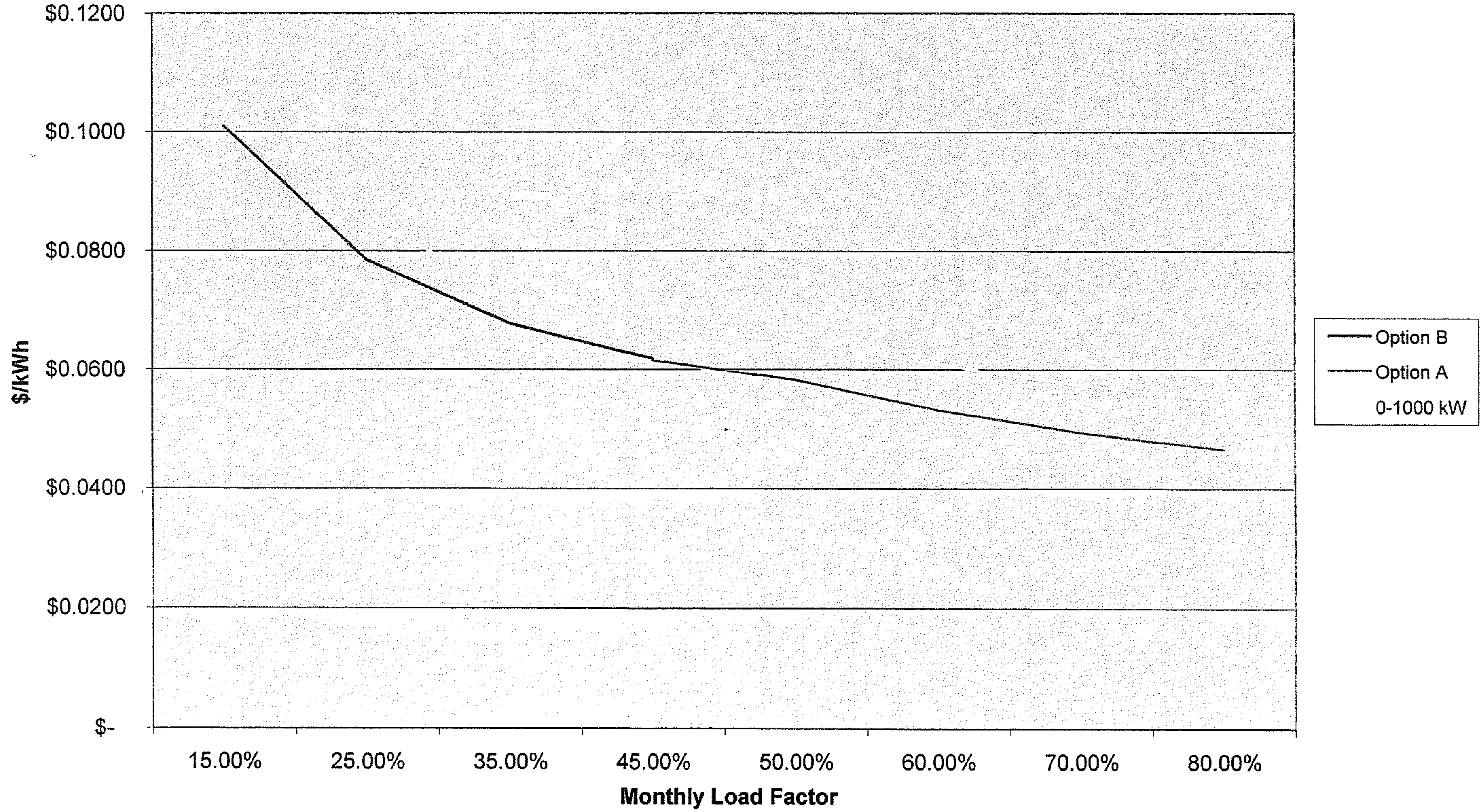
Response to Staff 2nd, Item 9b
Attachment
Proposed Rates @
900 kW Demand



Response to Staff 2nd, Item 9b
Attachment
Proposed Rates
@ 1,000 kW Demand



Response to Staff 2nd, Item 9b
Attachment
Proposed Rates
@ 1,500 kW Demand



KENERGY CORP.
RESPONSE TO THE COMMISSION'S SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 10) Refer to page 16 of the Gaines Testimony. Starting at line 9, Mr. Gaines states that the distribution increase for the lighting class was applied evenly at .85 percent. How was this percentage increase determined?

.

Response) The 0.85% produces the target non-power cost revenue increase of $13,871, or 0.9%. The target revenue was determined as part of the overall strategy of gradually moving rates towards parity. Hence, the percentage increase is less than half the overall 2.3% percentage of non-power cost increase. Also, see the related response to Item 4.

Witness) Jack Gaines

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 11) Refer to Exhibits 10A and 10B. Provide these exhibits electronically with the formulas intact and unprotected.

Response) Refer to attached CD.

Witness) Jack Gaines

Item 12) Refer to Exhibit 10A.

a. Pages 2 and 3, lines 3 and 11, and page 4, lines 3 and 16, include adjustments to the number of customer bills booked or KWH booked. Explain the reasons for the adjustments.

b. Refer to pages 2 to 5. Each of these pages contains a footnote which states, "Proposed Non FAC PPA tariff of $(0.000963) less base rate roll-in of .0008760 adjusted for normalized test year KWH sales." On each of these pages, the footnote appears to be in reference to an amount of ($.0000910) used in the Rider section of the billing analysis. Explain how the two amounts referenced in the footnote are used to calculate the ($.0000910).

c. On page 5 under the "Proposed Revenue" column K, approximately half-way down the column, the number $163,838 is shown. Provide the origin of the number and its purpose in that column.

d. Refer to page 6, line 19. The present rate shown for the 19,500 Lumen-250W-MH-Flood Light is $8.69. The rate shown for this light in Kenergy's current tariff is $8.61. Explain the discrepancy.

e. Refer to page 9. The adjustment to eliminate power costs is shown on line 9 as $716,699. Provide the location of this adjustment on the income statement presented in Exhibit 5 of the application.

f. Refer to page 10, the Direct Served Class A Consumption Analysis, and Exhibit Seelye-6, page 3 of 3 in Case No. 2011-00036 (BREC Application for a General Adjustment in Rates, filed March 1, 2011).

(1) Refer to columns H and K of page 10. The amounts referenced in columns H and K on line 17 are $14,249,307 and $7,124,654, respectively. The corresponding amounts shown in Exhibit Seelye-6 are $14,229,306 and $7,114,653, respectively. Explain the reasons for the differences.

(2) Explain why the billing adjustments of $657,687.71 shown on Exhibit Seelye-6 are not included on Kenergy's page 10.

g. Refer to page 10. Footnote 2 states "Base fixed energy 7,297,080,000 plus base variable energy - 265,331,800." This footnote is in reference to an amount of $7,113,321,360 used in the billing analysis. Explain how this footnote supports the $7,113,321,360.

Response **a)** Lines 2 and 10 come from raw, unadjusted billing data extracted from the billing system. Lines 3 and 11 are adjustments to come back to the amounts per Kenergy's books.

b) The $(0.000963) and $0.000876 are the wholesale factors of BREC for the non-FAC PPA and base rate roll-in, respectively. They must be adjusted for distribution losses before applying at retail. To achieve an exact match of wholesale costs and retail revenue related to the non-FAC PPA, the net retail factor is calculated as follows:

1,190,284,548 KWH purchased x $(0.000963)	=	$(1,146,244)
1,190,284,548 KWH purchased x $0.000876	=	$ 1,042,689
Net Costs		$ (103,685)
KWH Sales - Exh. 10a, page 1, col. F, line 37	÷	1,140,513,641
Net Retail Factor per KWH sold	=	$(0.000091)

c) It is the sum of lines 12, 24 and 31 and is not integral to the Exhibit.

d) The $8.69 is an input error. It should be $8.61.

e) Line 13, column c of page 1 of Exhibit 5 is an adjustment of $(634,289). It is shown on line 32 of page 14 of Exhibit 10a and is the sum of lines 21 and 30. Line 21 is the $(716,699) adjustment referenced.

f) (1) The differences are due to an input error in column H. The amount in column H should be $14,229,306 and since column K is 50% of column H, the $20,000 difference is a $10,000 in column K. The amounts should match Exhibit Seely-6.

(2) They were inadvertently omitted. It should be noted, however, that for Kenergy Class A purchased power cost is a direct pass-through and any adjustment to power cost will be equally offset by an adjustment to revenue.

g) The footnote is incorrect. The base variable energy is 183,758,640.

Witness) Jack Gaines

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 13) Refer to Exhibit 16.

a. Provide an electronic copy of the cost of service study ("COSS") in Excel format with the formulas intact and unprotected.

Response) The electronic copy of the COSS is provided in the file "Kenergy - 2010 COSS Case No. 2011-00035".

b. Identify and explain all differences in methodology, if any, between the COSS filed in this case and the COSS filed by Kenergy in its most recent rate case.

Response) The methodology is the same as the most recent Kenergy filing with the exception of the allocation of purchased power demand costs. In the previous filing, the demand allocator was based upon the contribution of each rate class to the average monthly peak demand for the Kenergy system, consistent with the billing methodology charged by Big Rivers. The new wholesale tariff bills capacity on the basis of Kenergy's contribution to the Big Rivers monthly peaks. The demand allocator is now based upon the contribution of each rate class to the 12 monthly peaks for Big Rivers.

c. Refer to page 5.

(1) Explain why total Expenses, line 13, differs from Total Expenses on page 159 of this Exhibit, line 23.

Response) **(1)** Page 5 shows the total costs including interest expense. Page 159 shows the total revenue requirements including interest expense and operating margins, or return, produced by the proposed rates. The revenue requirements are higher than costs by the operating margins of $3,899,425. Please refer to Exhibit 16, page 6, line 15 for this amount.

(2) Explain the basis for the allocations of line items 16, 17, and 18 to the rate classes or provide the location in the COSS where these allocations are calculated.

Response) Line 16, interest income includes deferred compensation of $108,000 and interest income of $664,000. Deferred compensation is allocated using Administrative and General Expenses. Interest is allocated on the basis of interest expense. The blended allocation is then used to allocate the total amount of $772,000. In the electronic file, this allocation is shown on the tab "Abbreviated Income Statement", Lines 108 and 109.

Line 17, Other Income, is allocated on Number of Consumers.

Line 18, Capital Credits, is allocated on Sales Revenue under the present rates.

d. Refer to pages 7-10. These calculations include margins at 2.14 percent of rate base. Explain the basis for the 2.14 percent and provide the location in the COSS where it is calculated.

Response) Please refer to page 6 of Exhibit 16. The 2.14% is calculated as the ratio of operating margins on Line 15 ($3,899,000) divided by the rate base on Line 21 ($182,233,000). The calculation is made in the electronic file on the "Abbreviated Income Statement" tab in cell C:97.

e. Refer to page 11, line 10. Explain how Other Revenue - Three-Rent-Pole Attachments was allocated among the rate classes.

Response) Revenue from Rents and Pole Attachments is allocated on the basis of rate base allocated to each class for Primary 3-Phase and Primary Single-Phase shown on Pages 110 and 113 respectively. Since these rate base items are heavily weighted to accounts 364 and 356, this method is a surrogate for allocating based on poles overhead line. This calculation can be found in the electronic file on the "Input Revenue" tab, lines 69 through 72.

f. Refer to pages 14-23. Explain the meaning of "Elect" used in the Basis column.

Response) The basis is used to separate plant and expenses related to non-electricity businesses. For Kenergy, all plant and expenses are for electric service so the basis used is "ELECT" for each item.

g. Refer to page 73.

(1) Refer to line 88 in the Distribution Operations section. Provide the rationale for using DIST-OH2 as the basis for allocating Account 584, Underground Lines Expense.

(2) Refer to line 80 in the Distribution Maintenance section. Provide the rationale for using DIST-OH1 as the basis for allocating Account 594, Underground Lines.

Response g 1&2) The ratio used for both Account 584 and Account 594 are incorrect. Account 584 should use the ratio "Dist-UG2" and Account 594 should use the ratio "Dist-UG1".

h. Refer to page 95. It appears that the ratios on this page are the same as those used in the total system subfunctionalization of the utility plant, labor, and utility expenses in the COSS. State whether the ratios on page 95 were developed to subfunctionalize utility plant, labor and utility expenses or if the subfunctionalization of utility plant resulted in the ratios. If the former, explain in detail the origin of the ratios. If the latter, explain in detail the origin of the numbers on the subfunctionalization pages.

Response) Some of the ratios shown on page 95 are used to sub-functionalize plant. Then, the plant balances that result from the sub-functionalization are used to create the other ratios. For example, the ratios Lines 1 through 3 functionalize Production, Transmission, and Sub-transmission plant directly to each functional category. In a similar manner, Lines 6 through 14 sub-functionalize

Accounts 364 through 370. Accounts 364 through 368 are sub-functionalized into primary three-phase, primary single-phase and secondary using data from the Continuing Property Records ("CPR"). Account 369 is sub-funtionalized to services with the exception of a small amount of plant that is used only for security lights, which is sub-functionalized accordingly. For meters, the CPR data was used to separate plant into three phase and single phase uses.

The other ratios are calculated from the plant balances resulting from the application of the sub-functionalization ratios to each account. The ratios on line 19 through 22 are calculated by adding the accounts referenced in the description. For example, the DIST-OH1 on line 19 is calculated by summing accounts 364, 365, & 369. The balances used are shown on pages 23 and 24.

i. Refer to page 101. Explain why all of the direct assignment classifications are to the Security Lights class.

Response) Accounts 371 and 373 are all plant investment for lights. Both accounts are directly assigned to security lights. The other ratios are calculated on plant balances, as referenced in item h) above, but each calculation results in a 1.00 factor to lights because lights are the only direct assignment in the COSS.

j. Provide the minimum intercept calculations referred to on page 9 of the Gaines Testimony.

Response) The minimum-intercept calculations are provided in the file "Staff 2-13j - Plant Classification – 2010".

Witness) Jack Gaines

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 14) Refer to the testimony of Steve Thompson, Exhibit 7, page 2, lines 23 to 29.

a. How does Kenergy define the term "normal" as it relates to heating and cooling degree days?

b. Provide a monthly comparison of "normal" heating and cooling degree days to actual heating and cooling degree days for the test year.

c. Provide the same comparison provided in response to part b. of this request for the months of July and August 2010.

Response **a)** The 2009 load forecast prepared by GDS Associates for Kenergy uses the 20-year average from the Evansville, Indiana National Weather Service station. See Item 14, pages 2-3 of 5 for the calculation used.

b) The monthly comparison for the test year ending June 30, 2010 is shown on Item 14, page 4 of 5.

c) Item 14, page 5 of 5, contains the above referenced information.

Witness) Steve Thompson

Kenergy Corp.
Henderson, Kentucky

2009 Load Forecast

June 2009

In Cooperation with
Big Rivers Electric Corporation

GDS Associates, Inc.

long, humid and hot, with the maximum monthly high temperature averaging just over 96° Fahrenheit in July over the last 20 years.

Heating and cooling degree days for Evansville, Indiana were used in the forecasting models to quantify the impacts of weather on energy consumption. A degree day represents the difference between the average temperature for a given day and a base temperature[4]. Positive differences represent cooling degree days, and negative differences represent heating degree days. Cooling and heating degree days measured at the Evansville airport are presented in Table 2.1.

Table 2.1
Degree Days

Year	Heating Degree Days	Cooling Degree Days	Total Degree Days
1989	4,830	1,396	6,226
1990	3,856	1,380	5,236
1991	4,253	1,757	6,010
1992	4,217	1,240	5,457
1993	4,652	1,613	6,265
1994	4,180	1,489	5,669
1995	4,314	1,773	6,087
1996	5,068	1,224	6,292
1997	4,901	1,119	6,020
1998	3,863	1,629	5,492
1999	4,149	1,284	5,433
2000	4,710	1,289	5,999
2001	4,233	1,377	5,610
2002	4,410	1,737	6,147
2003	4,529	1,143	5,672
2004	4,253	1,269	5,522
2005	4,320	1,544	5,864
2006	4,044	1,342	5,386
2007	4,159	1,888	6,047
2008	4,690	1,421	6,111
Average	4,382	1,446	5,827

2.4 Power Supply

Kenergy purchases power through fifty (50) non-dedicated and nineteen (19) dedicated metering points on the Big Rivers transmission system. The tariffs under which Big Rivers bills Kenergy became effective July 18, 1998 upon approval by the Kentucky Public Service Commission, with subsequent amendments to add

[4] The National Oceanic and Atmospheric Administration computes degree days using a base of 65 degrees.

KENERGY CORP.

RESPONSE TO THE PSC SECOND DATE REQUEST

ITEM 14b

(a)	(b)	(c)		(d)	(e)	
	Actual			Normal		
	Cooling	Heating		Cooling	Heating	
June 2009	368	4		300	6	
July 2009	270	0		413	0	
August 2009	309	0		379	1	
September 2009	178	18		176	41	
October 2009	0	345		34	238	
November 2009	0	447		2	554	
December 2009	0	923		0	890	
January 2010	0	1,148		0	936	
February 2010	0	974		0	770	
March 2010	0	539		5	587	
April 2010	43	152		27	278	
May 2010	167	53		111	81	
12 Month Total	1,335 +	4,603 =	5,938	1,446 +	4,382 =	5,828

Note: Due to the approximate one-month billing lag between usage and billed month, June 2009 thru May 2010 was shown to correspond to the June 30, 2010 test year.

KENERGY CORP.

RESPONSE TO THE PSC SECOND DATE REQUEST

ITEM 14c

(a)	(b)	(c)	(d)	(e)
	Actual		Normal	
	Cooling	Heating	Cooling	Heating
June 2010	423	0	305	7
July 2010	489	0	407	0
August 2010	514	0	376	1
	1,426	0	1,088	8

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 15) Refer to the testimony of Robert N. Welsh ("Welsh Testimony"), Exhibit 9, page 19, lines 6 to 9. Provide documentation of the approval by Rural Utility Services ("RUS") of the current depreciation rates and the rates resulting from the depreciation study filed in the application.

Response) Item 15, pages 2 - 6 of 6, contains the above referenced information.

Witness) Steve Thompson

USDA Rural Development

United States Department of Agriculture
Rural Development

October 20, 2006

file

Mr. Mark A. Bailey
President & Chief Executive Officer
Kenergy Corporation
P.O. Box 18
Henderson, Kentucky 42419-0018

Dear Mr. ~~Bailey~~ MAB:

We have reviewed the depreciation study prepared for Kenergy Corporation (Kenergy) using traditional depreciation study methodologies and actual December 31, 2005, plant and reserve balances. The study requests the Rural Utilities Service's (RUS) approval of depreciation rates as listed below. RUS approval is required since Kenergy is setting depreciation rates that vary from those prescribed in RUS Bulletin 183-1, *Depreciation Rates and Procedures.*

Based upon the information provided in the study and in response to your request, RUS hereby approves the utilization of the following depreciation rates.

	Account	Proposed Rates
362	Station Equipment Supervisory Control	2.2%
362.1	Equipment	6.7%
362.2	Microwave Equipment	6.7%
362.223	Microwave Towers	3.0%
362.4	Owenboro Tower	4.0%
364	Poles, Towers & Fixtures	4.2%
365	Overhead Conductors & Devices	3.4%
366	Underground Conduit	2.2%
367	Underground Conductors and Devices	3.1%
368	Line Transformers	2.9%
369	Services	3.8%
370	Meters	3.3%
371	Installations on Customers' Premises	4.4%
373	Street Lighting & Signal Systems	3.8%

RUS' approval is granted for a 5-year period beginning January 1, 2007, and terminating December 31, 2011. If Kenergy wishes to continue to utilize depreciation rates that fall outside of the RUS prescribed ranges of rates beyond this 5-year period, a revised depreciation study updating this information must be submitted to RUS.

If you have any questions or if we can be of further assistance, please contact Mr. Joseph Badin, Director, Northern Regional Division, 1400 Independence Ave. SW, Stop 1566, Washington, D.C. 20250-1566.

Sincerely,

Nivin A. Elgohary
Deputy Assistant Administrator
Rural Development - Utilities Programs
Electric Programs

P.O. Box 18 • 6402 Old Corydon Road
Henderson, Kentucky 42419-0018
(800) 844-4832

May 12, 2010

Mr. Joseph S. Badin, Director
Northern Regional Division – STOP 1566
U.S. Department of Agriculture
Rural Utilities Service
14th & Independence Avenue SW
Washington, D. C. 20250

Dear Mr. Badin:

Enclosed please find a copy of the 2010 depreciation study prepared by Welsh Group, LLC and approved by Kenergy Corp. (see attached board resolution).

As indicated in the enclosed letter from RUS dated October 20, 2006, the current rates expire December 31, 2011. Kenergy is requesting RUS approval to extend the current rates until the implementation of its next general revenue increase, projected for March 1, 2012. Should Kenergy elect to defer the new revenues implementation another year, it requests the current depreciation rates be extended to March 1, 2013.

Since the proposed overall composite rate is increasing from 3.58% to 3.84%, an annual increase in depreciation expense of $580,245 will occur. Kenergy desires the expense increase to coincide with the next general revenue increase. The Kentucky Public Service Commission has directed Kenergy in the final order in Case No. 2008-00323 (enclosed), that it cannot change depreciation rates without their approval.

If Kenergy elects to file its next general rate application around September 1, 2011 for implementation around March 1, 2012, it must have the new RUS approved depreciation rates by February 1, 2011 to begin work on the cost of service study.

Please contact me at sthompson@kenergycorp.com or (270)689-6139 or feel free to contact Robert Welsh at (703)450-0845 if you have any questions.

Sincerely,

Steve Thompson

Steve Thompson
Vice President - Finance

Enclosure

cc: Robert Welsh

USDA Rural Development

United States Department of Agriculture
Rural Development

JAN 24 2011

Mr. Sanford Novick
President & Chief Executive Officer
Kenergy Corp
P. O. Box 18
6402 Old Corydon Road
Henderson, Kentucky 42419-0018

Dear Mr. Novick:

This is in response to a letter dated May 12, 2010, from Mr. Steve Thompson, to Mr. Joseph S. Badin, Director, Northern Regional Division of Rural Utilities Service (RUS), regarding Kenergy Corp's (Kenergy) request for RUS approval to extend the depreciation rates approved by RUS in its letter dated October 20, 2006.

In response to your request, RUS hereby approves the continuation of the previously approved depreciation rates for the distribution facilities to December 31, 2012. RUS also approves the rates included in Kenergy's 2010 Depreciation Study as follows:

Account	Proposed Rates
362 -Station Equipment and Supervisory Control	1.9%
362.1 - Equipment	5.0%
362.2 - Microwave Equipment	5.0%
362.223 - Microwave Towers	2.8%
362.4 - Owensboro Fiber	4.0%
364 - Poles, Towers & Fixtures	4.7%
365 - Overhead Conductors & Devices	3.9%
366 - Underground Conduit	2.2%
367 - Underground Conductors and Devices	3.1%
368 - Line Transformers	2.9%
369 - Services	3.8%
370 - Meters	5.0%
371 - Installations on Customers' Premises	5.4%
373 - Street Lighting & Signal Systems	3.8%

1400 Independence Ave, S.W. · Washington DC 20250-0700
Web: http://www.rurdev.usda.gov

If Kenergy wishes to continue to utilize the 2010 Study depreciation rates that fall outside of the prescribed ranges of rates beyond December 31, 2017, a revised depreciation study updating this information must be submitted to RUS.

Please let us know if we can be of further assistance.

Sincerely,

JAMES F. ELLIOTT
Acting Deputy Assistant Administrator
Rural Utilities Service-Electric Program

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 16) Refer to Welsh Testimony, page 11 at lines 18 to 22 concerning net salvage. Mr. Welsh states that "the copper wire replacement project made the past net salvage significantly more than what is expected in the future."

a. Provide a full explanation of the copper replacement project mentioned.

b. Fully explain and quantify how this project has had such a significant impact on net salvage.

Response a) The copper replacement project is a generic term for two projects, one in Green River Electric and one in Henderson Union, to replace the copperweld conductor cable. The Green River project was approved in 1995 and the Henderson Union project in 1996 after the March 1996 ice storm. The Green River project had approximately 1,025 miles of copper and Henderson Union had about 500 miles. The bulk of the copper was replaced in the 1996 - 2008 time period. As of 2011, Green River had about 420 miles left and Henderson Union about 30 miles. The remaining cable is now being replaced at a slower rate of servicing individual customers and the cost to replace is prohibitive. Going forward the slower replacement rate of about 25 miles a year will minimize the project impact on net salvage.

b) The copper wire replacement project was a large multi-year project that started in 1996. The average net salvage for the total distribution plant for the ten years prior to project (1985-1995) was a negative 39.1%. The average net salvage for the ten years after the project started (1997-2007) was a negative 58.3%. This significant increase in net salvage is reflective of the impact of the project. In the 2005 Depreciation Study the impact of the project was carefully reviewed by looking at project work orders. The analysis concluded that a primary driver of the high net salvage was the low average unit costs (because of age) of the retirement plant. A secondary drive, although not as consistent, was the plant retired by the project tended to generate higher than average removal costs either because of its type of plant or placement. In the 2005 Depreciation Study most of this additional net salvage was adjusted out of the depreciation rates since it was expected that net salvage would return to lower pre-project levels upon completion of the project. This expectation still holds in the 2010 Depreciation Study and the higher project driven net salvage was adjusted out of the depreciation rates for the affected accounts.

Witness) Robert N. Welsh

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 17) Refer to Exhibit 12, Independent Auditors Report - 2009, Notes to Financial Statements, item 2, Utility Plant. The notes states that "[a]t December 31, 2009 the FEMA receivable was approximately $3,000,000."

a. Provide the current status of this account.

b. Identify the account number where this receivable was recorded.

c. Does the test year include any expenses resulting from the 2009 ice storm that were not reimbursed by FEMA? If so, provide an analysis of the amounts and the accounts in which they are recorded.

Response **a-b)** The FEMA receivable at February 28, 2011 was $4,310,549 recorded in account 142.200 - Other Accounts Receivable.

c) Yes, see Exhibit 5, page 15, for the pro-forma adjustment removing Line of Credit Interest Expense caused by the 2009 ice storm. There were no other expenses not reimbursed by FEMA.

Witness) Steve Thompson

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 18) Refer to Kenergy's response to the First Data Request of Commission Staff ("Staff's First Request"), Item 9, which provides a comparison of income statement account levels for the test period and the 12 months immediately preceding the test period.

a. Page 4 of 27 shows that Account 419000, Interest-Dividend Income, increase by $416,021.43, from $618,391.83 to $1,034,413.26, from 2009 to 2010 test period. Provide a detailed explanation for why this account increased by this magnitude.

Response) Interest earned on the Cushion of Credit balance at 5% increased $241,455, as the average balance in account 224.600, RUS advance payments unapplied increased during the test year. Deferred compensation earnings on a frozen plan for a retired CEO increased $326,040, due to a large loss recorded in December 2008. This has zero impact on margins as an offsetting amount is recorded in account 920.000. Interest on short-term investments dropped $56,884 due to the decrease in the federal funds rate, while an error on posting the receivable from CFC occurring in April 2009 and corrected in August 2009 caused $94,730 of the increase. See Exhibit 5, page 18, for the pro-forma adjustment on account 419.000.

Witness) Steve Thompson

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
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2011 RATE APPLICATION

Item 18) **b.** Page 16 of 27 shows that Account 583000, Distribution-Exp-Ops Overhead Line, increased by $767,693.39, from $896,117.10 to $1,663,810.49, from 2009 to the 2010 test period. Provide a detailed explanation for why this account increased by this magnitude.

Response) The increase resulted mainly from:

Kenergy employees labor and overheads	-	$ 84,790
Property taxes	-	$ 38,894
Entries made during test year correcting transformer installation labor	-	$183,729 [1]
Return to post 2009 ice storm levels for transformer installation labor	-	$489,754 [2]

[1] See Exhibit 5, page 8, line 15 for the adjustment removing this expense from the test year.

[2] The test year level of activity is representative of ongoing operations. During the January/February ice storm, over 1,100 transformers were replaced.

Witness) Steve Thompson

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
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2011 RATE APPLICATION

Item 18) c. Page 17 of 27 shows that Account 588200, Dist-Exp-Ops Storm Damage, decreased by $200,147.00, from $200,147.00 to $0.00, from 2009 to the 2010 test period. Provide a detailed explanation for why this account decreased by this magnitude.

Response) The $200,147 represents a payment to an outside contractor to perform a one-time system-wide assessment to locate cleanup work following the January/February 2009 ice storm.

Witness) Steve Thompson

2011 RATE APPLICATION

Item 18) **d.** Page 18 of 27 shows that Account 592100, Dist Exp-Main-Supervisory Control, increased by $30,214.99, from $102,490.13 to $132,705.12, from 2009 to the 2010 test period. Provide a detailed explanation for why this account increased by this magnitude.

Response) Increase results mainly from the recurring expense of the SCADA System Software maintenance agreement.

Witness) Steve Thompson

Item 18) **e.** Page 18 of 27 shows that Account 592200, Dist Exp Main-Microwave System, increased by $49,731.64, from $61,031.61 to $110,763.25, from 2009 to the 2010 test period. Provide a detailed explanation for why this account increased by this magnitude.

Response) Results mainly from Kenergy labor and overheads increasing $21,736 along with tower inspection and light replacement expenses of $16,875 and $17,570 respectively.

Witness) Steve Thompson

Item 18) **f.** Page 18 of 27 shows that Account 593200, Dist Exp Main-Storm Damage, decreased by $333,041.27, from $333,041.27 to $0.00, from 2009 to the 2010 test period. Provide a detailed explanation for why this account decreased by this magnitude.

Response) Decrease due to zero major storm expense during the test year.

Witness) Steve Thompson

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 18) **g.** Page 18 of 27 shows that Account 593300, Maintenance of Overhead Lines-ROW, increased by $1,664,657.85, from $2,995,645.02 to $4,660,302.87, from 2009 to the 2010 test period. Provide a detailed explanation for why this account increased by this magnitude.

Response) See Exhibit 5, page 9 for the pro-forma adjustment relating to Vegetation Management.

Witness) Steve Thompson

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 18) **h.** Page 19 of 27 shows that Account 597000, Dist Exp-Main-Meters, increased by $66,375.54, from $141,163.96 to $207,539.50, from 2009 to the 2010 test period. Provide a detailed explanation for why this account increased by this magnitude.

Response) Increase results from new meter testing requirement for CT meters.

Witness) Steve Thompson

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 18) **i.** Page 21 of 27 shows that Account 908000, Customer Assistance Expense, decreased by $73,216.22, from $237,864.42 to $164,649.31, from 2009 to the 2010 test period. Provide a detailed explanation for why this account decreased by this magnitude.

Response) Decrease due mainly to Kenergy employee labor and overheads dropping $34,998 and payments due to an incentive program that ended decreasing $32,972.

Witness) Steve Thompson

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
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2011 RATE APPLICATION

Item 18) **j.** Page 22 of 27 shows that Account 920000, Adm-Gen Exp-Ops-Executive Salary, increased by $08,794.79, from $1,022,750.66 to $1,531,545.45, from 2009 to the 2010 test period. Provide a detailed explanation for why this account increased by this magnitude.

Response) Change mainly due to the earnings/loss from the frozen deferred compensation plan for a retired CEO increasing $326,040, due to the large loss recorded in December 2008. This has zero impact on margins as an offsetting amount is recorded in account 419.000, Interest Income. The remaining $180,306 results from more labor and overheads for Kenergy employees being charged to this account.

Witness) Steve Thompson

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 18) **k.** Page 24 of 27 shows that Account 923000, Outside Services - General, increased by $68,842.45, from $70,966.87 to $139,809.32, from 2009 to the 2010 test period. Provide a detailed explanation for why this account increased by this magnitude.

Response) The increase results mainly from the following expenses:

National Safety Council Audit	-	$10,130
Depreciation study	-	$19,300
Single Act FEMA Audits	-	$ 8,750
Pension Merger Consulting	-	$22,768
Work Force Management Study	-	$10,000
360 Degree Administrative Survey	-	$ 4,485

See Exhibit 5, page 8 for the pro-forms adjustment removing these one-time expenses from the test year.

Witness) Steve Thompson

2011 RATE APPLICATION

Item 18) **l.** Page 25 of 27 shows that Account 928000, Regulatory Comm. Expense, decreased by $91,455.21, from $103,152.93 to $11,697.72, from 2009 to the 2010 test period. Provide a detailed explanation for why this account decreased by this magnitude.

Response) There was a general rate application filed September 1, 2008 costing approximately $60,000.

Witness) Steve Thompson

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 18) **m.** Page 27 of 27 shows that Account 935000, Maint of General Plant, increased by $64,858.87, from $568,526.19 to $633,385.06, from 2009 to the 2010 test period. Provide a detailed explanation for why this account increased by this magnitude.

Response) The increase is due mainly to more labor and overheads of Kenergy employees being charged here during the test year vs. other areas.

Witness) Steve Thompson

Item 19) Refer to Kenergy's response to the Staff's First Request, Item 14.

a. Discuss how and when Kenergy determines that a "General Retirement" of patronage capital is appropriate. Include in this discussion how the amount to be retired is determined.

b. Explain how the target range of equity to total capital ratio of 30 percent to 40 percent was determined.

c. Explain why it is important for Kenergy to maintain equity to total capital ratio within its targeted range.

d. Explain why Kenergy has chosen not to make any general retirements of capital credits since 2006.

Response **a)** Kenergy's management reviews its financial condition annually and makes a recommendation to the Board of Directors relative to general retirements of patronage capital. Factors considered to determine when and how much to retire include the following listed items:

(1) The corporation's past financial performance, including TIER and DSC ratios and its equity to total capital ratio.
(2) The current board-accepted long-range financial forecast.
(3) Rate competitiveness, especially to adjacent utilities
(4) Lender requirements and mortgage covenants
(5) Regulatory body requirements
(6) Amount of cash reserves available for contingencies
(7) All other factors that may be relative at this time, such as new or pending legislation affecting the electric utility industry.

As provided in the bylaws, the Board of Directors may retire capital credits if it is determined the financial condition will not be impaired.

Witness) Sanford Novick

b) The 30% minimum level was taken from the Rural Utilities Service (RUS) loan contract provision Section 6.8 (see page 3) that requires Kenergy to receive prior RUS approval if, after giving effort to a general retirement of patronage capital, the equity of the borrower falls below 30% of its total assets. The 40% level was selected based on Kenergy's understanding that this was the upper limit the Commission was comfortable with for distribution cooperatives (see pages 4 - 5). The Capital Credits Task Force Report was issued in January 2005 by the National Rural Electric Cooperative Association and the National Rural Utilities Cooperative Finance Corporation. Its purpose is to serve as a guide to distribution cooperatives when making capital credit retirement decisions. On page 38 of the report (see page 6), it is suggested that a reasonable equity level for most distribution cooperatives is in the range of 30 to 50 percent, depending on the cooperative financial and competitive situation. (The full report was provided electronically in Case No. 2008-00323 in response to Item 11 of PSC Data Request No. 3.)

c) To enable Kenergy to prudently manage equity and debt capital that results in obtaining a reasonable cost of debt, maintaining reserves for contingencies such as the 2009 ice storm, complying with loan agreements and mortgage covenants, provide adequate capital to fund operating costs and plant growth, and to retire capital credits on a systematic basis.

Witness b-c) Steve Thompson

d) After considering the factors shown in the responses to Item 19a and c, management and the Board made a decision not to retire capital credits in 2007 - 2010.

Witness) Sanford Novick

(b) The Borrower shall not, without the written approval of RUS, voluntarily or involuntarily sell, convey or dispose of any portion of its business or assets (including, without limitation, any portion of its franchise or service territory) to another entity or person if such sale, conveyance or disposition could reasonably be expected to reduce the Borrower's existing or future requirements for energy or capacity being furnished to the Borrower under any wholesale power contract which has been pledged as security to RUS.

Section 6.7. Limitations on Using non-FDIC Insured Depositories.

Without the prior written approval of RUS, the Borrower shall not place the proceeds of the Loan or any loan which has been made or guaranteed by RUS in the custody of any bank or other depository that is not insured by the Federal Deposit Insurance Corporation or other federal agency acceptable to RUS.

Section 6.8. Limitation on Distributions.

Without the prior written approval of RUS, the Borrower shall not in any calendar year make any Distributions (exclusive of any Distributions to the estates of deceased natural patrons) to its members, stockholders or consumers except as follows:

(a) Equity above 30%. If, after giving effect to any such Distribution, the Equity of the Borrower shall be greater than or equal to 30% of its Total Assets; or

(b) Equity above 20%. If, after giving effect to any such Distribution, the Equity of the Borrower shall be greater than or equal to 20% of its Total Assets and the aggregate of all Distributions made during the calendar year when added to such Distribution shall be less than or equal to 25% of the prior year's margins.

Provided however, that in no event shall the Borrower make any Distributions if there is unpaid when due any installment of principal of (premium, if any) or interest on any of its payment obligations secured by the Mortgage, if the Borrower is otherwise in default hereunder or if, after giving effect to any such Distribution, the Borrower's current and accrued assets would be less than its current and accrued liabilities.

Section 6.9. Limitations on Loans, Investments and Other Obligations.

The Borrower shall not make any loan or advance to, or make any investment in, or purchase or make any commitment to purchase any stock, bonds, notes or other securities of, or guaranty, assume or otherwise become obligated or liable with respect to the obligations of, any other person, firm or corporation, except as permitted by the Act and RUS Regulations.

Section 6.10. Depreciation Rates.

The Borrower shall not file with or submit for approval of regulatory bodies any proposed depreciation rates which are inconsistent with RUS Regulations.

Section 6.11. Historic Preservation.

The Borrower shall not, without approval in writing by RUS, use any Advance to construct any facilities which shall involve any district, site, building, structure or object which is included in, or eligible for inclusion in, the National Register of Historic Places maintained by the Secretary of the Interior pursuant to the Historic Sites Act of 1935 and the National Historic Preservation Act of 1966.

A28. Yes, it could. However, it should be pointed out that Green River does not operate under any form of equity management plan and has not retired any of its patronage capital since 1974 when the board discontinued capital credit retirements to estates of deceased patrons. Since Green River does not indicate any immediate plans to rotate capital on any basis, the input to the formula for equity payout would be zero. Also at the end of the test period, Green River has achieved an equity ratio of 58.4 percent which is above a reasonable equity level for a RECC. Considering a planning horizon of ten years in which to reduce equity to a more reasonable 40 percent level, a negative return component must be added to the equity payout and normal growth rate components which results in a return on equity of only 3.86 percent and a weighted cost of capital of 4.60 percent. Based on the Staff adjusted test year, this return would result in a required TIER of 1.98x.

Q29. What is your recommendation to the Commission on the revenue requirements for Green River in this case?

A29. Based on the results of this analysis, I would recommend that the Commission allow Green River a TIER of 2.00 which is the TIER requested by Green River in this case.

Q30. Please explain the adjustments to operating expenses you wish to address in your testimony.

$$RORE = {}^{r}ng + {}^{r}be + {}^{r}epo$$

Where: ${}^{r}ng$ = Normal (historic) rate of growth in total capital
${}^{r}be$ = Rate of growth required to build equity
${}^{r}epo$ = Rate of Equity Payout (including rotation retirements and/or special situation payouts.)

In order to explain in greater detail how this formula works, it is necessary to establish hypothetical financial data and make certain assumptions with regard to the amounts required to calculate a return on equity. To facilitate preparation of this discussion, I will again use the 1978 KAEC Study and establish the following parameters:

Accumulated Equity	$ 300,000
Total Debt	700,000
Total Capital	$1,000,000
Weighted Average Cost of Debt =	4.5%
Annual Compound Growth Rate =	8.75%

Capital Credit Rotation Policy = estates only = .5 of 1% of equity capital each year.

Target Equity =	40%
Planning horizon =	10 years

Using the previously stated formula, RORE = ${}^{r}ng + {}^{r}be + {}^{r}epo$ and the above assumptions, the ${}^{r}ng$ component would be 8.75 percent. Given that no systematic rotation of capital credits exists but that the annual payout is 1/2 of 1 percent, the ${}^{r}epo$ would be .5. To determine the ${}^{r}be$ component the following formula is generally used:

The cash members receive from capital credits retirements may effectively offset part of costs paid through rates. Depending on the retirement method adopted, this can have an immediate impact.

Regulatory Requirements

Cooperatives that are subject to state regulation of rates or other activities must comply with any regulatory rulings affecting capital credits retirements.[15]

HOW DO CO-OPS FUND CAPITAL CREDITS RETIREMENTS?

Even co-ops that are strongly committed to retiring capital credits sometimes express concern about having adequate cash to fund capital credits retirements and meet other needs. While margins and depreciation on plant investment are sources of funds for patronage capital retirements, there are competing uses for the cash, such as plant additions and principal payments on existing debt.

Some cooperatives have expressed a concern that they may have to adopt higher rates or borrow funds to repay capital credits. As a practical matter, planning for availability and use of cash involves a process that considers funding capital additions, amortization of existing debt, capital credits retirements, rates and rate parity, and equity levels. Cooperatives should develop equity management plans that take into consideration the many uses of funds and the need to build and/or maintain financial strength for future ratepayers. Cooperatives pay for capital additions with general funds, and often requisition debt after construction is completed. Good cash management demands that funds be borrowed only when they can be put to use, as the co-op is unlikely to be able to earn a return on invested funds that is higher than the cost of borrowing. It is an acceptable practice to borrow, if necessary, in order to have the actual cash to retire patronage capital. If the cooperative is following its equity management plan, it should be indifferent to the actual source of cash at the time of retirement. Ultimately, all costs to the cooperative are funded out of rates, either directly or through payments of principal and interest.

Recommendation

Adequate Equity Level

Each electric cooperative should seek to maintain an equity level adequate to retire capital credits on an annual basis and meet the goals and requirements of its equity management plan. The task force suggests that a reasonable equity level for most distribution systems is in the range of 30 to 50 percent, depending on the cooperative's financial and competitive situation.

[15] See page 61.

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 20) Refer to Kenergy's response to Staff's First Request, Item 34, page 2 of 10.

a. With the exception of the depreciation study, provide a detailed explanation of the nature of the items listed that make up the total professional services reported under "Other."

b. Provide a detailed supporting schedule which shows the payee, dollar amount, reference and date paid.

c. Provide a comparative analysis of Professional Services for the calendar years 2006 through 2010. Expenses should be summarized by the major categories of expense incurred in each year.

Response) **a)** The $594.62, $10,000 and $4,485 have been removed for rate-making purposes. See Exhibit 5, page 8, lines 3 and 5, and Exhibit 5, page 7, line 14. The $821.04 KAEC - Cust. Stmts Sales Tax Audit was for legal work to protest a sales tax audit finding. The $450.00 tax form assistance was for a CPA to review the annual IRS Form 990. The $1,950 is an annual required Affirmative Action Plan Study. The remaining items are legal work for direct-served customers.

b) This information is provided on pages 4-5 and 7-10 of Item 34.

c) Item 20, page 2 of 2, contains the above referenced information.

Witness) Steve Thompson

COMPARATIVE ANALYSIS OF PROFESSIONAL SERVICES															
FOR CALENDAR YEARS 2006 - 2010															
Calendar Year	Legal	PSC 2008-00323 Legal	Other PSC Cases Legal	Attorney Insurance	Financial Audits / Consulting	401K Audit	Pension/HR Consulting	Long Range Plan & 3 Year Work Plan	Depreciation Study	PSC Cases Consulting	Work Mgmt System Consulting	PBX Phone System Consulting	Safety Assessment & Audits	CEO Search	TOTALS:
2010	66,901.67		7,922.30	12,965.52	30,530.00	6,750.00	21,358.40	49,793.84	19,300.00	6,413.75	5,000.00				**226,935.48**
2009	55,649.71		9,519.93	11,842.44	25,096.25	6,500.00	9,993.00	18,260.12			10,000.00	120,571.14	210,277.04		**477,709.63**
2008	47,821.67	10,156.00	9,127.30	11,307.60	19,525.00	13,503.06	4,385.00	437.50		20,789.65					**137,052.78**
2007	50,186.62		13,146.68	11,307.60	17,015.00	5,341.95		51,582.64		787.50				61,244.93	**210,612.92**
2006	62,595.47			10,532.73	33,171.38	8,456.84	5,950.00		13,095.00	23,635.68				18,032.00	**175,469.10**
	283,155.14	10,156.00	39,716.21	57,955.89	125,337.63	40,551.85	41,686.40	120,074.10	32,395.00	51,626.58	15,000.00	120,571.14	210,277.04	79,276.93	**1,227,779.91**

Item 21) Refer to Kenergy's response to Staff's First Request, Item 35. Explain how Kenergy determined that advertising costs for the rate case should be $60,000 when the advertising cost incurred in Kenergy's most recent rate case, Case No. 2008-00323, were $16,707.

Response) In October 2010, Kenergy Corp. placed ads regarding a Public Service Commission ("PSC") hearing on a fuel-adjustment clause in most of the newspapers in our service territory. The PSC took issue with the number of newspapers used, arguing that we needed to place an ad in every newspaper in our 14-county region. In the past, we had only run the ads in major daily newspapers in our region because they reach our entire service territory.

Even though we published the October 12th PSC hearing in more newspapers than we ever had in the past, the PSC required us to run ads in six additional newspapers. During this time, our attorney, Frank King, had several conversations with PSC officials. Mr. King forwarded our CEO a copy of a PSC order entered in a pending Blue Grass Energy case in which the PSC required Blue Grass Energy to print public notices in more publications.

After several conversations with PSC officials and after reviewing the Blue Grass Energy case, our attorney advised Kenergy staff that we would be required to publish future notices in all 14 counties that we serve. The cost of doing that increased our publication costs to about $60,000, as compared to $16,707 during the last rate-case filing. In the past, Kenergy only published full-page ads in three large daily newspapers in our service territory.

In essence, the increased costs are due to stricter public-notice requirements implemented by the PSC between these two rate filings. (See pages 3 - 6 of 6.)

Witness) David Hamilton

KENTUCKY PRESS SERVICE

KENTUCKY PRESS SERVICE
101 CONSUMER LANE
FRANKFORT,KY 40601-
Voice (502) 223-8821 Fax (502) 875-2624

Friday, March 25, 2011 01:50 PM

Invoice

Agency RENEE BEASLEY JONES
KENERGY
3111 Fairview Drive
Owensboro, KY 42303-

PO Number
Order 11031KK0

Client KENERGY

Newspaper / Caption	Run Date	Ad Size	Rate	Rate Name	Color	Disc.	Total
CALHOUN MCLEAN CO. NEWS							
PUBLIC NOTICE - CASE NO. 2011-00035	03/03/2011	6 x 21	$7.60	CLDIS	$0.00	0.0000%	$957.60
PUBLIC NOTICE - CASE NO. 2011-00035	03/10/2011	6 x 21	$7.60	CLDIS	$0.00	0.0000%	$957.60
PUBLIC NOTICE - CASE NO. 2011-00035	03/17/2011	6 x 21	$7.60	CLDIS	$0.00	0.0000%	$957.60
CENTRAL CITY LEADER NEWS							
PUBLIC NOTICE - CASE NO. 2011-00035	03/08/2011	6 x 21	$7.33	CLDIS	$0.00	0.0000%	$923.58
PUBLIC NOTICE - CASE NO. 2011-00035	03/15/2011	6 x 21	$7.33	CLDIS	$0.00	0.0000%	$923.58
PUBLIC NOTICE - CASE NO. 2011-00035	03/22/2011	6 x 21	$7.33	CLDIS	$0.00	0.0000%	$923.58
EDDYVILLE HERALD-LEDGER							
PUBLIC NOTICE - CASE NO. 2011-00035	03/02/2011	6 x 19.713	$6.50	SAU	$0.00	0.0000%	$768.81
PUBLIC NOTICE - CASE NO. 2011-00035	03/09/2011	6 x 19.713	$6.50	SAU	$0.00	0.0000%	$768.81
PUBLIC NOTICE - CASE NO. 2011-00035	03/16/2011	6 x 19.713	$6.50	SAU	$0.00	0.0000%	$768.81
HARDINSBURG HERALD-NEWS							
PUBLIC NOTICE - CASE NO. 2011-00035	03/02/2011	6 x 21	$8.24	CLDIS	$0.00	0.0000%	$1,038.24
PUBLIC NOTICE - CASE NO. 2011-00035	03/09/2011	6 x 21	$8.24	CLDIS	$0.00	0.0000%	$1,038.24
PUBLIC NOTICE - CASE NO. 2011-00035	03/16/2011	6 x 21	$8.24	CLDIS	$0.00	0.0000%	$1,038.24
HARTFORD OHIO CO. TIMES-NEWS							
PUBLIC NOTICE - CASE NO. 2011-00035	03/03/2011	6 x 21	$7.00	CLDIS	$0.00	0.0000%	$882.00
PUBLIC NOTICE - CASE NO. 2011-00035	03/10/2011	6 x 21	$7.00	CLDIS	$0.00	0.0000%	$882.00
PUBLIC NOTICE - CASE NO. 2011-00035	03/17/2011	6 x 21	$7.00	CLDIS	$0.00	0.0000%	$882.00

ANY QUESTIONS CONCERNING TEARSHEETS AND ALL REQUESTS FOR ACCOUNT CREDIT MUST BE MADE WITHIN FIVE DAYS OF THE DATE OF THIS INVOICE. IF THE REQUEST IS NOT RECEIVED WITHIN FIVE DAYS, THE CLIENT IS RESPONSIBLE FOR FULL PAYMENT OF THE INVOICE AMOUNT. Amount Due Subject to 1.5% Service Charge After 30 Days Please Pay From This Invoice. No Statement Will Be Sent.

KENTUCKY PRESS SERVICE

KENTUCKY PRESS SERVICE
101 CONSUMER LANE
FRANKFORT,KY 40601-
Voice (502) 223-8821 Fax (502) 875-2624

Friday, March 25, 2011 01:50 PM

Invoice

Agency RENEE BEASLEY JONES
KENERGY
3111 Fairview Drive
Owensboro, KY 42303-

PO Number
Order 11031KK0

Client KENERGY

Newspaper

Caption	Run Date	Ad Size	Rate	Rate Name	Color	Disc.	Total
HAWESVILLE HANCOCK CLARION							
PUBLIC NOTICE - CASE NO. 2011-00035	03/03/2011	6 x 21	$8.00	CLDIS	$0.00	0.0000%	$1,008.00
PUBLIC NOTICE - CASE NO. 2011-00035	03/10/2011	6 x 21	$8.00	CLDIS	$0.00	0.0000%	$1,008.00
PUBLIC NOTICE - CASE NO. 2011-00035	03/17/2011	6 x 21	$8.00	CLDIS	$0.00	0.0000%	$1,008.00
HENDERSON GLEANER							
PUBLIC NOTICE - CASE NO. 2011-00035	03/03/2011	6 x 20.75	$17.55	SAU	$0.00	0.0000%	$2,184.98
PUBLIC NOTICE - CASE NO. 2011-00035	03/10/2011	6 x 20.75	$17.55	SAU	$0.00	0.0000%	$2,184.98
PUBLIC NOTICE - CASE NO. 2011-00035	03/17/2011	6 x 20.75	$17.55	SAU	$0.00	0.0000%	$2,184.98
MADISONVILLE MESSENGER							
PUBLIC NOTICE - CASE NO. 2011-00035	03/03/2011	6 x 21.25	$17.23	CLDIS	$0.00	0.0000%	$2,196.82
PUBLIC NOTICE - CASE NO. 2011-00035	03/10/2011	6 x 21.25	$17.23	CLDIS	$0.00	0.0000%	$2,196.82
PUBLIC NOTICE - CASE NO. 2011-00035	03/17/2011	6 x 21.25	$17.23	CLDIS	$0.00	0.0000%	$2,196.82
MARION CRITTENDEN PRESS							
PUBLIC NOTICE - CASE NO. 2011-00035	03/03/2011	6 x 21	$8.13	CLDIS	$0.00	0.0000%	$1,024.38
PUBLIC NOTICE - CASE NO. 2011-00035	03/10/2011	6 x 21	$8.13	CLDIS	$0.00	0.0000%	$1,024.38
PUBLIC NOTICE - CASE NO. 2011-00035	03/17/2011	6 x 21	$8.13	CLDIS	$0.00	0.0000%	$1,024.38
MORGANFIELD UNION CO. ADVOCATE							
PUBLIC NOTICE - CASE NO. 2011-00035	03/02/2011	6 x 21.5	$11.40	CLDIS	$0.00	0.0000%	$1,470.60
PUBLIC NOTICE - CASE NO. 2011-00035	03/09/2011	6 x 21.5	$11.40	CLDIS	$0.00	0.0000%	$1,470.60
PUBLIC NOTICE - CASE NO. 2011-00035	03/16/2011	6 x 21.5	$11.40	CLDIS	$0.00	0.0000%	$1,470.60

ANY QUESTIONS CONCERNING TEARSHEETS AND ALL REQUESTS FOR ACCOUNT CREDIT MUST BE MADE WITHIN FIVE DAYS OF THE DATE OF THIS INVOICE. IF THE REQUEST IS NOT RECEIVED WITHIN FIVE DAYS, THE CLIENT IS RESPONSIBLE FOR FULL PAYMENT OF THE INVOICE AMOUNT. Amount Due Subject to 1.5% Service Charge After 30 Days Please Pay From This Invoice. No Statement Will Be Sent.

KENTUCKY PRESS SERVICE

KENTUCKY PRESS SERVICE

101 CONSUMER LANE
FRANKFORT,KY 40601-
Voice (502) 223-8821 Fax (502) 875-2624

Friday, March 25, 2011 01:50 PM

Invoice

Agency RENEE BEASLEY JONES
KENERGY
3111 Fairview Drive
Owensboro, KY 42303-

PO Number

Order 11031KK0

Client KENERGY

Newspaper

Caption	Run Date	Ad Size	Rate	Rate Name	Color	Disc.	Total
OWENSBORO MESSENGER-INQUIRER							
PUBLIC NOTICE - CASE NO. 2011-00035	03/03/2011	6 x 21	$32.01	CLDIS	$0.00	0.0000%	$4,033.26
PUBLIC NOTICE - CASE NO. 2011-00035	03/10/2011	6 x 21	$32.01	CLDIS	$0.00	0.0000%	$4,033.26
PUBLIC NOTICE - CASE NO. 2011-00035	03/17/2011	6 x 21	$32.01	CLDIS	$0.00	0.0000%	$4,033.26
PRINCETON TIMES LEADER							
PUBLIC NOTICE - CASE NO. 2011-00035	03/02/2011	6 x 21.5	$6.00	CLDIS	$0.00	0.0000%	$774.00
PUBLIC NOTICE - CASE NO. 2011-00035	03/09/2011	6 x 21.5	$6.00	CLDIS	$0.00	0.0000%	$774.00
PUBLIC NOTICE - CASE NO. 2011-00035	03/16/2011	6 x 21.5	$6.00	CLDIS	$0.00	0.0000%	$774.00
PROVIDENCE JOURNAL-ENTERPRISE							
PUBLIC NOTICE - CASE NO. 2011-00035	03/03/2011	6 x 21.5	$6.95	CLDIS	$0.00	0.0000%	$896.55
PUBLIC NOTICE - CASE NO. 2011-00035	03/10/2011	6 x 21.5	$6.95	CLDIS	$0.00	0.0000%	$896.55
PUBLIC NOTICE - CASE NO. 2011-00035	03/17/2011	6 x 21.5	$6.95	CLDIS	$0.00	0.0000%	$896.55
SMITHLAND LIVINGSTON LEDGER							
PUBLIC NOTICE - CASE NO. 2011-00035	03/08/2011	6 x 19.75	$10.13	SAU	$0.00	0.0000%	$1,200.40
PUBLIC NOTICE - CASE NO. 2011-00035	03/15/2011	6 x 19.75	$10.13	SAU	$0.00	0.0000%	$1,200.40
PUBLIC NOTICE - CASE NO. 2011-00035	03/22/2011	6 x 19.75	$10.13	SAU	$0.00	0.0000%	$1,200.40

ANY QUESTIONS CONCERNING TEARSHEETS AND ALL REQUESTS FOR ACCOUNT CREDIT MUST BE MADE WITHIN FIVE DAYS OF THE DATE OF THIS INVOICE. IF THE REQUEST IS NOT RECEIVED WITHIN FIVE DAYS, THE CLIENT IS RESPONSIBLE FOR FULL PAYMENT OF THE INVOICE AMOUNT. Amount Due Subject to 1.5% Service Charge After 30 Days Please Pay From This Invoice. No Statement Will Be Sent.

KENTUCKY PRESS SERVICE

KENTUCKY PRESS SERVICE

101 CONSUMER LANE
FRANKFORT,KY 40601-
Voice (502) 223-8821 Fax (502) 875-2624

Friday, March 25, 2011 01:50 PM

Invoice

	RENEE BEASLEY JONES		
Agency	KENERGY	**PO Number**	
	3111 Fairview Drive	**Order**	11031KK0
	Owensboro, KY 42303-		
Client	KENERGY		

Newspaper Caption	Run Date	Ad Size	Rate	Rate Name	Color	Disc.	Total

Total Advertising	$58,077.66
Discounts	$0.00
Tax: USA	$0.00
Total Invoice	$58,077.66
Payments	$0.00
Adjustments	$0.00
Balance Due	$58,077.66

TEARSHEETS
CANNOT BE REPLACED

Payment is Due

ANY QUESTIONS CONCERNING TEARSHEETS AND ALL REQUESTS FOR ACCOUNT CREDIT MUST BE MADE WITHIN FIVE DAYS OF THE DATE OF THIS INVOICE. IF THE REQUEST IS NOT RECEIVED WITHIN FIVE DAYS, THE CLIENT IS RESPONSIBLE FOR FULL PAYMENT OF THE INVOICE AMOUNT. Amount Due Subject to 1.5% Service Charge After 30 Days Please Pay From This Invoice. No Statement Will Be Sent.

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 22) Refer to Kenergy's response to Staff's First Request, Item 49.

a. Describe the level of customer interest in the Demand-Side Management ("DSM") pilot programs noted in Kenergy's response. Provide the number of customers that are actually participating or have indicated a desire to participate.

b. Explain whether Kenergy has any plans to develop or establish DSM programs independent of Big Rivers Electric Corporation.

Response **a)** Kenergy had 29 members participate in the Energy Star Refrigerator Program that ran between October 1, 2010 and February 28, 2011. Kenergy intends to make the Energy Star Refrigerator Program a permanent program starting October 1, 2011.

Kenergy has not paid a rebate on the Energy Star New Home Program as of March 29, 2011. We have had approximately ten (10) calls from builders interested in the rebate program. Two of our largest builders, Jagoe Homes and Thompson Homes, have committed to participate in our Energy Star New Home Program.

b) Kenergy has no plans to develop or establish DSM programs independent of Big Rivers Electric Corporation.

Witness) David Hamilton

Item 23) Refer to Kenergy's response to Staff's First Request, Item 30.

a. Provide a summary schedule of Board of Directors fees and expenses, by member, utilizing the same expense categories as used in the detailed schedules provided in this response. Identify those expenses that Kenergy has removed for ratemaking purposes.

b. Provide the response to Item 30 electronically with all formulas intact and unprotected.

Response) **a.** Item 23, pages 2 - 3 of 3, contains the above referenced information.

b. Refer to the CD provided.

Witness) Steve Thompson

KENERGY
2011 RATE APPLICATION
ACCOUNT 930.210 - BOARD OF DIRECTORS
FOR 12 MONTHS ENDED JUNE 30, 2010

Director Name	Total Amount	Directors Emeritus	Chair Fee	Non Del/Alt Assoc Mtg exp	Other Mtg Fee	Other Mtg Mileage	Monthly Retainer	Director Bd fees	Del/Alt Assoc Exp	MRC	KAEC Bd Mtg Exp Cox	CEO Search Expense	Election Expense	Other
Marion Cecil	1,044.00	900.00	-	-	-	-	-	-	-	-	-	-	-	144.00
Glenn Cox	16,688.10	-	-	-	600.00	-	7,800.00	3,600.00	1,020.83	181.00	2,666.10	-	-	820.17
Royce Dawson	1,169.50	900.00	-	-	-	-	-	-	-	-	-	-	-	269.50
Bill Denton	12,469.80	-	-	-	600.00	-	7,800.00	3,600.00	-	31.90	-	-	-	437.90
Larry Elder	12,503.60	-	-	-	600.00	-	7,800.00	3,600.00	-	-	-	-	-	503.60
Allan Eyre	20,054.99	-	-	7,801.39	600.00	44.00	7,800.00	3,300.00	-	36.30	-	-	-	473.30
R.C. Johnson	1,207.60	800.00	-	-	-	-	-	-	-	-	-	-	-	407.60
Chris Mitchell	18,539.83	-	1,100.00	3,721.04	300.00	-	7,800.00	3,600.00	1,328.54	31.00	-	-	-	659.25
Randy Powell	13,321.78	-	-	1,424.23	-	-	7,800.00	3,600.00	-	52.25	-	-	-	445.30
William Reid	15,636.51	-	-	3,576.06	600.00	-	7,800.00	3,000.00	-	-	-	-	-	660.45
John Warren	15,896.40	-	-	3,573.90	300.00	-	7,800.00	3,600.00	-	37.50	-	-	-	585.00
Bob White	19,589.00	-	-	6,771.60	600.00	-	7,800.00	3,600.00	-	100.85	-	-	-	716.55
Brent Wigginton	15,778.79	-	-	4,089.79	300.00	-	7,150.00	3,300.00	-	112.50	-	-	-	826.50
Sandra Wood	17,347.58	-	-	5,066.48	-	-	7,800.00	3,600.00	-	50.00	-	-	-	831.10
General Board Expenses	32,484.72	-	-	-	-	-	-	-	-	305.28	-	-	5,847.72	26,331.72
MRC Expenses	10,740.16	-	-	-	-	-	-	-	-	10,740.16	-	-	-	-
Totals:	224,472.36	2,600.00	1,100.00	36,024.49	4,500.00	44.00	85,150.00	38,400.00	2,349.37	11,678.74	2,666.10	-	5,847.72	34,111.94
				(a)		(a)								
	(2,298.97)	These items have been exluded for rate-making purposes:												
	(3,148.02)	(a) = 36,069 - Exhibit 5, Page 7, Line 5												
	(1,672.89)	(1) Exhibit 5, Page 7, Line No.:												
	(3,144.94)	(6)	(3)	(5)	(7)	(5)	(2)			(9)				
	214,207.54													

KENERGY CORP.
2011 RATE APPLICATION
ACCOUNT 930.210 - BOARD OF DIRECTORS - Detail of "Other" Column
FOR 12 MONTHS ENDED JUNE 30, 2010

Director Name	Other	Mgmt Quarterly	Rural Electric	Bd Mtg Meals	Director Insurance	Postage	Service Award	Mileage Board	Mileage Emeritus
Marion Cecil	144.00	-	-	-	-	-	-	-	144.00
Glenn Cox	820.17	25.00	43.00	97.17	-	-	-	655.00	-
Royce Dawson	269.50	-	-	-	-	-	-	-	269.50
Bill Denton	437.90	25.00	43.00	75.40	-	-	-	294.50	
Larry Elder	503.60	25.00	43.00	75.40	-	-	-	360.20	
Allan Eyre	473.30	25.00	43.00	75.40	-	-	-	329.90	-
R.C. Johnson	407.60	-	-	-	-	-	-	-	407.60
Chris Mitchell	659.25	25.00	43.00	75.40	-	-	-	515.85	
Randy Powell	445.30	25.00	43.00	75.40	-	-	-	301.90	
William Reid	660.45	25.00	43.00	75.40	-	-	-	517.05	
John Warren	585.00	25.00	43.00	75.40	-	-	-	441.60	
Bob White	716.55	25.00	43.00	-	-	-	-	648.55	
Brent Wigginton	826.50	25.00	43.00	75.40	-	-	-	683.10	
Sandra Wood	831.10	25.00	43.00	75.40	-	-	-	687.70	
General Board Expenses	26,331.72	-	-	799.60	24,664.07	868.05			
MRC Expenses	-	-	-	-	-	-	-	-	-
Totals:	34,111.94	275.00	473.00	1,575.37	24,664.07	868.05	-	5,435.35	821.10
									(1)

This item has been excluded for rate-making purposes.
(1) Reference Exhibit 5, Page 7, Line 8

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 24) Refer to Kenergy's response to Staff's First Request, Item 6.

a. In the format used in this response, provide an update of the current interest rates for outstanding long-term debt as of the most recent month available and continue to update monthly until the date of the hearing in the proceeding.

b. On pages 4 and 5, the date in the heading of the schedules is December 31, 2010. Column (f) of the schedules indicates that the interest rates are as of December 31, 2009. Confirm which date is correct.

c. Refer to page 3, line 8, and page 5, line 80. Provide a detailed explanation of the RUS cushion of credit, what the amounts represent and how they were determined.

Response **a)** Item 24, pages 2 - 3 of 6, contains the above referenced information.

b) December 31, 2009 is the correct date.

c) Item 24, pages 4 - 6 of 6, contains the above referenced information.

Witness) Steve Thompson

KENERGY CORP.
2011 RATE APPLICATION
SCHEDULE OF OUTSTANDING LONG-TERM DEBT
FOR THE TEST YEAR ENDED JUNE 30, 2010

Line No.	Note No. (a)	Type of Debt Issue (b)	Date of Issue (c)	Date of Maturity (d)	Amount Outstanding (e)	Interest Rate on 03/31/11 (f)	Interest Rate Term (g)	Type of Obligation (h)	Annualized Cost Col. (e) x Col. (f) (i)	Actual Test Year Interest Cost (j)
1	1B170	35 yr Note	12/05/86	2021	$ -	5.00%	Fixed to Maturity	RUS Mortgage		46,998
2	1B172	35 yr Note	12/05/86	2021	$ -	5.00%	Fixed to Maturity	RUS Mortgage		46,998
3	1B180	35 yr Note	06/23/88	2023	$ -	5.00%	Fixed to Maturity	RUS Mortgage		51,617
4	1B182	35 yr Note	06/23/88	2023	$ -	5.00%	Fixed to Maturity	RUS Mortgage		51,617
5	1B190	35 yr Note	10/29/90	2025	$ -	5.00%	Fixed to Maturity	RUS Mortgage		61,495
6	1B192	35 yr Note	06/29/92	2027	$ -	5.00%	Fixed to Maturity	RUS Mortgage		61,495
7	1B340	35 yr Note	11/26/86	2021	$ -	5.00%	Fixed to Maturity	RUS Mortgage		29,084
8	1B342	35 yr Note	11/26/86	2021	$ -	5.00%	Fixed to Maturity	RUS Mortgage		29,084
9	1B350	35 yr Note	05/24/89	2024	$ -	5.00%	Fixed to Maturity	RUS Mortgage		44,599
10	1B353	35 yr Note	05/24/89	2024	$ -	5.00%	Fixed to Maturity	RUS Mortgage		45,841
11	1B200	35 yr Note	01/28/93	2028	$ 1,345,454	5.00%	Fixed to Maturity	RUS Mortgage	$ 67,273	68,501
12	1B201	35 yr Note	01/28/93	2028	$ 358	5.00%	Fixed to Maturity	RUS Mortgage	$ 18	$ 18
13	1B205	35 yr Note	01/28/93	2029	$ 1,344,238	5.00%	Fixed to Maturity	RUS Mortgage	$ 67,212	$ 68,519
14	1B210	35 yr Note	12/14/94	2029	$ 1,280,009	4.00%	Fixed until 8/31/13	RUS Mortgage	$ 51,200	$ 52,141
15	1B211	35 yr Note	12/14/94	2029	$ 352	3.125%	Fixed until 05/31/11	RUS Mortgage	$ 11	$ 11
16	1B215	35 yr Note	12/14/94	2029	$ 1,197,899	3.125%	Fixed until 05/31/11	RUS Mortgage	$ 37,434	$ 38,193
17	1B220	35 yr Note	07/01/97	2032	$ 1,587,898	3.50%	Fixed until 12/31/13	RUS Mortgage	$ 55,576	$ 56,481
18	1B225	35 yr Note	07/01/97	2032	$ 1,600,750	4.125%	Fixed to Maturity	RUS Mortgage	$ 66,031	$ 67,025
19	1B360	35 yr Note	04/21/93	2029	$ 957,215	5.00%	Fixed to Maturity	RUS Mortgage	$ 47,861	$ 48,692
20	1B366	35 yr Note	04/21/93	2029	$ 983,264	5.00%	Fixed to Maturity	RUS Mortgage	$ 49,163	$ 50,013
21	1B370	35 yr Note	08/12/98	2033	$ 2,203,989	5.125%	Fixed to Maturity	RUS Mortgage	$ 112,954	$ 114,367
22	1B375	35 yr Note	01/19/99	2034	$ 356,606	5.00%	Fixed to Maturity	RUS Mortgage	$ 17,830	$ 18,059
23	1B376	35 yr Note	02/10/99	2034	$ 335,629	5.00%	Fixed to Maturity	RUS Mortgage	$ 16,781	$ 16,997
24	1B377	35 yr Note	05/12/99	2034	$ 755,165	5.00%	Fixed to Maturity	RUS Mortgage	$ 37,758	$ 38,243
25	1B378	35 yr Note	05/26/99	2034	$ 478,271	5.00%	Fixed to Maturity	RUS Mortgage	$ 23,914	$ 24,221
26	1B380	35 yr Note	02/01/01	2036	$ 15,933,952	2.125%	Fixed until 03/31/12	RUS Mortgage	$ 338,596	$ 343,989
27	1B381	35 yr Note	02/01/01	2036	$ 10,260,470	2.125%	Fixed until 04/30/17	RUS Mortgage	$ 218,035	$ 297,264
28	1B382	35 yr Note	02/01/01	2036	$ 5,503,859	3.750%	Fixed until 01/31/12	RUS Mortgage	$ 206,395	$ 209,007
29	1B383	35 yr Note	02/01/01	2036	$ 7,166,004	3.250%	Fixed until 07/31/12	RUS Mortgage	$ 232,895	$ 236,047
30	1B384	35 yr Note	02/01/01	2036	$ 8,429,637	2.625%	Fixed until 03/31/13	RUS Mortgage	$ 221,278	$ 224,556
31	1B570	35 yr Note	06/19/99	2034	$ 266,825	5.00%	Fixed to Maturity	RUS Mortgage	$ 13,341	$ 13,513
32	Subtotal - Rural Utilites Service (RUS)				$ 61,987,843				$ 1,881,558	$ 2,454,688
33	1B390	35 yr Note	01/31/06	2041	$ 3,845,291	4.690%	Fixed to Maturity	RUS Mortgage	$ 180,344	$ 181,816
34	1B391	35 yr Note	01/31/06	2041	$ 3,857,198	5.120%	Fixed to Maturity	RUS Mortgage	$ 197,489	$ 198,981
35	1B392	35 yr Note	01/31/06	2041	$ 4,332,778	4.900%	Fixed to Maturity	RUS Mortgage	$ 212,306	$ 213,973
36	1B393	35 yr Note	01/31/06	2041	$ 4,337,553	5.070%	Fixed to Maturity	RUS Mortgage	$ 219,914	$ 221,594
37	1B394	35 yr Note	01/31/06	2041	$ 4,971,452	4.470%	Fixed to Maturity	RUS Mortgage	$ 222,224	$ 224,109
38	1B395	35 yr Note	01/31/06	2041	$ 5,022,758	4.690%	Fixed to Maturity	RUS Mortgage	$ 235,567	$ 237,490
39	Subtotal - Treasury- (RUS guaranteed)				$ 26,367,030				$ 1,267,844	$ 1,277,963
40	F0010	35 yr Note	07/01/03	2037	$ 5,551,282	4.940%	Fixed to Maturity	RUS Mortgage	$ 274,233	$ 277,217
41	F0015	35 yr Note	07/01/03	2037	$ 4,626,069	4.940%	Fixed to Maturity	RUS Mortgage	$ 228,528	$ 231,015
42	F0020	35 yr Note	07/01/03	2037	$ 5,551,282	4.940%	Fixed to Maturity	RUS Mortgage	$ 274,233	$ 277,217
43	F0025	35 yr Note	07/01/03	2037	$ 4,029,108	4.940%	Fixed to Maturity	RUS Mortgage	$ 199,038	$ 201,204
44	F0030	35 yr Note			$ 9,000,000	3.544%	Fixed to Maturity	RUS Mortgage	$ 318,960	$ 318,960

KENERGY CORP.
2011 RATE APPLICATION
SCHEDULE OF OUTSTANDING LONG-TERM DEBT
FOR THE TEST YEAR ENDED JUNE 30, 2010

Line No.	Note No. (a)	Type of Debt Issue (b)	Date of Issue (c)	Date of Maturity (d)	Amount Outstanding (e)	Interest Rate on 03/31/11 (f)	Interest Rate Term (g)	Type of Obligation (h)	Annualized Cost Col. (e) x Col. (f) (i)	Actual Test Year Interest Cost (j)
45	F0035	35 yr Note			$ 9,000,000	4.537%	Fixed to Maturity	RUS Mortgage	$ 408,330	$ 208,359
46	Subtotal - Federal Financing Bank(RUS guaranteed)				$ 37,757,741				$ 1,703,322	$ 1,513,972
47	Economic Dev Loan	10 yr Note	02/20/04	2014	$ 179,166	0.00%	Fixed to Maturity	RUS Mortgage	$ -	
48	Economic Dev Loan	10 yr Note	01/31/07	2017	$ 279,166	0.00%	Fixed to Maturity	RUS Mortgage	$ -	
49	Economic Dev Loan	10 yr Note	05/31/07	2017	$ 361,574	0.00%	Fixed to Maturity	RUS Mortgage	$ -	
50	Subtotal - Economic Dev Loan				$ 819,907	(1)			$ -	$ -
51	ML0501T1	35 yr Note	07/01/97	2032	$ 1,529,542	4.51%	Fixed until 10/14/11	CoBank Mortgage	$ 68,982	$ 71,163
52	ML0501T2	35 yr Note	12/05/86	2019	$ 972,906	3.77%	Fixed until 02/17/12	CoBank Mortgage	$ 36,679	$ 39,773
53	ML0501T4	35 yr Note	10/05/88	2022	$ 1,022,755	3.77%	Fixed until 02/17/12	CoBank Mortgage	$ 38,558	$ 41,381
54	ML0501T5	35 yr Note	02/03/84	2017	$ 755,010	3.74%	Fixed until 03/18/15	CoBank Mortgage	$ 28,237	$ 38,455
55	ML0501T6	35 yr Note	10/05/93	2028	$ 1,223,764	3.74%	Fixed until 03/18/15	CoBank Mortgage	$ 45,769	$ 61,068
56	ML0501T7	35 yr Note	01/05/94	2029	$ 1,195,262	3.52%	Fixed until 2/16/16	CoBank Mortgage	$ 42,073	$ 67,320
57	ML0501T8	35 yr Note	06/15/92	2025	$ 1,264,151	4.71%	Fixed until maturity	CoBank Mortgage	$ 59,542	$ 71,343
58	ML0501T10	35 yr Note	10/02/01	2026	$ 3,067,754	4.51%	Fixed until 10/14/11	CoBank Mortgage	$ 138,356	$ 144,387
59	ML0501T11	10 yr Note	09/19/03	2014	$ 1,805,005	4.29%	Fixed to Maturity	CoBank Mortgage	$ 77,435	$ 96,578
60	ML0501T12	11 yr Note	04/05/04	2015	$ 749,330	3.99%	Fixed to Maturity	CoBank Mortgage	$ 29,898	$ 34,055
61	ML0501T13	12 yr Note	04/05/04	2016	$ 956,544	4.12%	Fixed to Maturity	CoBank Mortgage	$ 39,410	$ 43,947
62	ML0501T14	13 yr Note	04/05/04	2017	$ 675,337	4.24%	Fixed to Maturity	CoBank Mortgage	$ 28,634	$ 31,427
63	ML0501T15	14 yr Note	04/05/04	2018	$ 1,257,163	4.32%	Fixed to Maturity	CoBank Mortgage	$ 54,309	$ 58,925
64	ML0501T19	17 yr Note	08/18/04	2021	$ 479,417	5.59%	Fixed until 02/16/12	CoBank Mortgage	$ 26,799	$ 28,012
65	ML0501T20	25 yr Note	08/18/04	2029	$ 801,265	5.59%	Fixed until 02/16/12	CoBank Mortgage	$ 44,791	$ 45,884
66	ML0501T21	29 yr Note	08/18/04	2033	$ 1,266,723	5.59%	Fixed until 02/16/12	CoBank Mortgage	$ 70,810	$ 72,154
67	ML0501T22	10 yr Note	06/30/10	2020	$ 9,110,101	3.76%	Fixed to Maturity	CoBank Mortgage	$ 342,540	$ 986
68	Subtotal - Cobank				$ 28,132,031				$ 1,172,821	$ 946,857
69										
70	Total Long-Term Debt, Annualized Cost and				$ 155,064,553				$ 6,025,546	$ 6,193,481
71	Test Year Cost									
72										
73	Annualized Cost Rate [Total								3.8858%	
74	Col.(j) / Total Col. (e)]									
75										
76	Actual Test Year Cost Rate									3.9941%
77	[Total Col. (j) / Total Reported in									
78	Col. (e)]									
79										

80			
81	$	155,064,553	Line No. 68, column (f) above
82	$	(16,391,779)	RUS cushion of credit balance at 06/30/10
83	$	(4,915,136)	Principal due in 1 year (RUS Form 7, Line 45)
84	$	133,757,638	RUS Form 7, Line 41

(1) All Cobank interest rates include a .65% reduction for capital credit refunds.

USDA Rural Development

Committed to the future of rural communities.

Electric Programs

Cushion of Credit (Advance Payment) Account

In accordance with the provisions of Section 313 of the Rural Electrification Act of 1936 (RE Act), as amended, the Rural Utilities Service (RUS) established a cushion of credit program. Under this program, RUS borrowers may make voluntary deposits into a special cushion of credit account. A borrower's cushion of credit account balance accrues interest to the borrower at a rate of 5 percent per annum. The amounts in the cushion of credit account (deposits and earned interest) can only be used to make scheduled payments on loans made or guaranteed under the RE Act.

If you have any questions concerning the cushion of credit program, please contact the Direct Loan and Grant Program at 314-457-4049.

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224.500		0010	INTEREST ACCRUED DEFERRED RUS NOTES			$	.00
224.600		0010	RUS ADVANCED PAYMENTS UNAPPLIED	19,501,071.80		$	19,501,071.80
2869	1 31	100139	16INTEREST INCOME-CUSHION-OF-CREDIT	82,812.77		$	19,583,884.57
2870	2 28	100138	91DEBT PAYMENT BY CUSHION-OF-CREDIT		525,829.63	$	19,058,054.94
2871	2 28	100139	16INTEREST INCOME-CUSHION-OF-CREDIT	72,433.55		$	19,130,488.49
2872	3 31	100138	42DEBT PAYMENT BY CUSHION-OF-CREDIT		1,036,337.67	$	18,094,150.82
2873	3 31	100139	16INTEREST INCOME-CUSHION-OF-CREDIT	78,625.83		$	18,172,776.65
2874	4 30	100138	68DEBT PAYMENT BY CUSHION-OF-CREDIT		525,829.63	$	17,646,947.02
2875	4 30	100139	16INTEREST INCOME-CUSHION-OF-CREDIT	72,200.36		$	17,719,147.38
2876	5 31	100138	47DEBT PAYMENT BY CUSHION-OF-CREDIT		521,189.82	$	17,197,957.56
2877	5 31	100139	16INTEREST INCOME-CUSHION-OF-CREDIT	72,825.80		$	17,270,783.36
2878	6 30	100138	67DEBT PAYMENT BY CUSHION-OF-CREDIT		954,221.68	$	16,316,561.68
2879	6 30	100139	16INTEREST INCOME-CUSHION-OF-CREDIT	75,217.65		$	16,391,779.33
228.100		0010	ACCRUED LEAVE-K WEST EMPLOYEES		340,003.88	$	340,003.88CR
2880	1 31	100034	KENERGY WEST ACCRUED LEAVE	7,337.94		$	332,665.94CR
2881	2 28	100034	KENERGY WEST ACCRUED LEAVE	7,760.81		$	324,905.13CR
2882	3 28	100034	KENERGY WEST ACCRUED LEAVE	1,454.34		$	323,450.79CR
2883	6 20	100034	KENERGY WEST ACCRUED LEAVE	2,055.90		$	321,394.89CR
228.200		0010	POST RETIREMENT HEALTH INS-HEADQTRS			$	.00
228.250		0010	POST RET HEALTH BENEFITS-DIRECTORS		4,785.50	$	4,785.50CR
2884	1 31	100030	CASH DISBURSEMENTS	585.52		$	4,199.98CR
2885	2 28	100030	CASH DISBURSEMENTS	585.52		$	3,614.46CR
2886	3 31	100030	CASH DISBURSEMENTS	585.52		$	3,028.94CR
2887	4 30	100030	CASH DISBURSEMENTS	585.52		$	2,443.42CR

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					12/31/09	168
6295	9 30 090020	CASH RECEIPTS		9,000,000.00	$ 13,622,000.00	
224.480	0010	LT DEBT-RUS TREASURY LOAN			$ .00	
224.500	0010	INTEREST ACCRUED DEFERRED RUS NOTES			$ .00	
224.600	0010	RUS ADVANCED PAYMENTS UNAPPLIED	12,685,144.90		$ 12,685,144.90	
6296	1 31 090139	16INTEREST INCOME-CUSHION-OF-CREDIT	53,872.81		$ 12,739,017.71	
6297	2 28 090139	16INTEREST INCOME-CUSHION-OF-CREDIT	48,865.94		$ 12,787,883.65	
6298	3 31 090139	16INTEREST INCOME-CUSHION-OF-CREDIT	54,593.35		$ 12,842,477.00	
6299	4 30 090139	16INTEREST INCOME-CUSHION-OF-CREDIT	52,777.30		$ 12,895,254.30	
6300	5 31 090139	16INTEREST INCOME-CUSHION-OF-CREDIT	54,760.67		$ 12,950,014.97	
6301	6 30 090139	16INTEREST INCOME-CUSHION-OF-CREDIT	53,216.54		$ 13,003,231.51	
6302	7 31 090139	16INTEREST INCOME-CUSHION-OF-CREDIT	55,216.41		$ 13,058,447.92	
6303	8 31 090139	16INTEREST INCOME-CUSHION-OF-CREDIT	55,450.90		$ 13,113,898.82	
6304	9 30 090030	CASH DISBURSEMENTS	9,000,000.00		$ 22,113,898.82	
6305	9 30 090138	77DEBT PAYMENT BY CUSHION-OF-CREDIT		937,589.25	$ 21,176,309.57	
6306	9 30 090139	16INTEREST INCOME-CUSHION-OF-CREDIT	61,156.23		$ 21,237,465.80	
6307	9 30 090139	16INTEREST INCOME-CUSHION-OF-CREDIT		642.50	$ 21,236,823.30	
6308	10 31 090138	82DEBT PAYMENT BY CUSHION-OF-CREDIT		525,829.63	$ 20,710,993.67	
6309	10 31 090139	16INTEREST INCOME-CUSHION-OF-CREDIT	90,036.92		$ 20,801,030.59	
6310	11 30 090138	76DEBT PAYMENT BY CUSHION-OF-CREDIT		525,829.63	$ 20,275,200.96	
6311	11 30 090139	16INTEREST INCOME-CUSHION-OF-CREDIT	85,408.95		$ 20,360,609.91	
6312	12 31 090138	45DEBT PAYMENT BY CUSHION-OF-CREDIT		943,435.64	$ 19,417,174.27	
6313	12 31 090139	16INTEREST INCOME-CUSHION-OF-CREDIT	83,897.53		$ 19,501,071.80	
228.100	0010	ACCRUED LEAVE-K WEST EMPLOYEES		434,592.72	$ 434,592.72CR	
6314	1 18 090034	KENERGY WEST ACCRUED LEAVE	2,623.06		$ 431,969.66CR	
6315	2 15 090034	KENERGY WEST ACCRUED LEAVE	825.94		$ 431,143.72CR	
6316	3 29 090034	KENERGY WEST ACCRUED LEAVE	1,761.34		$ 429,382.38CR	

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Available Keys:

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KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 25) Kenergy is requesting an adjustment in existing rates that will result in Kenergy attaining a Times Interest Earned Ratio ("TIER") of 2.0X.

a. Describe the methodology employed by Kenergy in determining that 2.0X was the appropriate TIER on which to base its requested rate increase.

b. Is Kenergy aware of any studies performed by RUS or the National Rural Utilities Cooperative Finance Corporation on the subject of the appropriate TIER level for an electric cooperative? If yes, identify the studies and when they were performed.

c. Kenergy's request in this case for a 2.0X TIER would produce net margins of roughly $6.1 million. For each of the five calendar years immediately preceding the test year, provide the approximate net margins that would have been realized if Kenergy had achieved a TIER of 2.0X.

Response **a)** Please refer to the Capital Management Policy found as Item 14, page 2 of 2 of the PSC First Data Request. After evaluating the long-term financial forecast, and Kenergy's current equity to total capital, Kenergy elected to request the maximum TIER of 2.0X being allowed by the PSC in recent distribution cooperative rate cases. As demonstrated by the most recent five-year history (see Item 25, page 2 of 2), a 2.00 TIER granted by the PSC on a historical test year basis only generated a 1.25 average actual TIER, the RUS minimum when the best 2 out of 3 most recent calendar years are considered.

b) CFC has performed the following studies:

1. "Commitment to Excellence - A Guide to Developing Board Policies for Financial Best Practices" - May 2004.

Included in this study is Section D - Chapter 11 "Equity Management - Achieving a Balance."

At the bottom of page 96 of this study, CFC lists these additional resources:

- NRECA and CFC, (1976), Capital Credits Study Committee Final Report and Recommendations
- Equity management Model version 2.0. - Equity Management Modeling Computer Software. CFC, 2001. Excel compact disk or CFC Extranet.
- Internal Revenue Service - General Survey of 501 (c) (12) Cooperatives and Examinations of Current Issues www.irs.gov/pub/irs-tege/topice02.pdf
- 1980 Capital Credits Procedure Study

c) Item 25, page 3 of 3, contains the above reference information.

Witness) Steve Thompson

KENERGY CORP.
2011 RATE APPLICATION
PSC INFORMATION REQUEST NO. 2
ITEM 25C

Line No.	(a)	Test year June 30, 2010	2009	2008	(b) 2007	(c) 2006	(d) 2005
1	Margins	*$3,867,730*	*$2,939,918*	*$785,131*	*$3,406,949*	-$1,594,436	$1,490,508
2	Interest Expense	$6,193,481	$6,114,726	$6,048,338	$5,776,153	$5,265,708	$4,198,637
3	Subtotal (line 1 + 2)	$10,061,211	$9,054,644	$6,833,469	$9,183,102	$3,671,272	$5,689,145
4							
5	Depreciation Expense (inc. clearing acct)	$8,627,306	$8,473,628	$8,158,148	$7,788,573	$6,742,046	$6,380,704
6	Subtotal (line 3 + 5)	$18,688,517	$17,528,272	$14,991,617	$16,971,675	$10,413,318	$12,069,849
7	Required Debt Service Payments	$10,906,465	$11,082,908	$11,015,176	$10,489,984	$9,488,994	$8,124,886
8							
9	Times Interest Earned Ratio	1.62	1.48	1.13	1.59	0.70	1.35
10	(line 3/line2)						
11	Debt Service Coverage Ratio	1.71	1.58	1.36	1.62	1.10	1.49
12	(line 6/line 7)						
13							
14	Margins if Kenergy would have achieved a 2.00 TIER		$6,114,726	$6,048,338	$5,776,153	$5,265,708	$4,198,637

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 26) Refer to Exhibit 5, page 5, Labor Adjustment.

a. Footnote 2 indicates that the calculation of proforma hours was based on 147 full-time employees. However, the supporting reference of Exhibit 5, page 5f, line 41 indicates that the total is 148. Explain this discrepancy.

b. Provide the calculation of the proforma full-time rate of $31.12.

c. Explain whether this rate includes any general, merit or step wage adjustments that occurred subsequent to the test year.

Response **a)** The difference is caused by an employee included in the 148 that had announced retirement and whose position was not going to be filled. Therefore, the pro-forma number of 147 positions was used.

b)	Sum of 147 employees' hourly rates at 1/1/11	$ 4,574.34
	times 2,080 hours	$9,514,627.20
	adjust for rounding	$ 624.00
	147 employees times 2,080 hours	$ 305,760.00
	Annual Dollars Divided by Annual Hours	$ 31.12

c) The rate includes the most recent wage rate available applied to the number of employees at the end of the test year.

Witness) Steve Thompson

Item 27) Refer to Kenergy's response to Staff's First Request, Item 27.

a. Provide a comparative schedule of employee benefits expense for the calendar years 2006 through 2010.

b. Fully describe Kenergy's process for selecting the providers of its employee benefit plans.

c. What other providers were considered for the current plans? Explain Kenergy's decision to select the current providers.

Response **a)** Item 27, page 3 of 3, contains the above referenced information.

b) Periodically, Kenergy will request bids for benefit plans by having potential vendors respond to a request for proposal that will best match its current plan designs. After management screens the proposals, the vice president of Human Resources will present the findings to the Board with a recommendation to retain or move its book of business. The Board reviews the data and votes to either accept management's recommendation or select another option.

c) Other providers that submitted inquiries regarding benefit plans (not all providers listed matched the criteria or elected not to bid):

Medical - National Rural Electric Association (NRECA), Humana, Blue Cross, Hartford and Kentucky Rural Electric Cooperative (KREC)

Dental - Delta Dental, NTECA and HRI

Retirement - NRECA, Fidelity, New York Life, PNC Bank, Diversified Investment Advisors and Stanley, Hunt, Dupree and Rhine.

Witness) Keith Ellis

Kenergy Corp
PSC Case No. 2011-00035
Employee Benefits Comparison 2006 - 2010

ITEM	2006	2007	2008	2009	2010	JUNE 30, 2010 TEST YEAR ANNUAL COST	PROFORMA COST
Health	1,804,563.04	1,784,515.01	1,812,679.69	1,889,526.82	1,957,717.09	1,944,076.00	2,249,800.00
Dental	108,686.47	102,427.99	106,102.33	90,819.44	90,238.81	90,379.00	94,158.00
Life	98,580.25	85,777.74	72,412.82	74,984.51	79,299.20	77,104.00	81,589.00
Long Term Disability	59,884.82	53,366.86	47,468.52	49,094.05	48,048.63	48,495.00	50,696.00
Subtotal Insurance	2,071,714.58	2,026,087.60	2,038,663.36	2,104,424.82	2,175,303.73	2,160,054.00	2,476,243.00
Pension	1,218,573.47	1,192,593.18	1,459,685.39	1,949,135.45	2,479,762.31	2,212,606.00	1,705,396.00
Total Benefits	3,290,288.05	3,218,680.78	3,498,348.75	4,053,560.27	4,655,066.04	4,372,660.00	4,181,639.00

2011 RATE APPLICATION

Item 28) Refer to Exhibit 5, page 12, and Kenergy's response to Staff's First Request, Item 37, pages 2 and 3.

a. Exhibit 5, page 12, line 13, shows a balance for account 370.000, Meters in the amount of $5,351,305. However, the response to Item 37 does not indicate an account 370.000, Meters. Explain this discrepancy and provide corrected schedules if necessary.

b. The response to Item 37 shows an account 370.1, AMI Meters, in the amount of $136,911. However, Exhibit 5, page 12, does not indicate an account 370.1, AMI Meters. Explain this discrepancy and provide corrected schedules if necessary.

Response **a)** Item 28, pages 2 - 3 of 4, contain the above referenced information.

b) Item 28, page 4 of 4, contains the above reference information. The pro-forma depreciation adjustment increased to $752,846 from $750,560.

Witness) Steve Thompson

Kenergy

2011 RATE APPLICATION

Depreciation Expenses
Modified March 30, 2011

Account Number	Item	(End of Test Year) Plant Account Balance	Depreciation Rate	Annual Depreciation
	Transmission plant:			
350.0	Land and land rights			
352.0	Structures and improvements			
353.0	Station equipment			
354.0	Towers and fixtures			
355.0	Poles and fixtures			
356.0	Overhead conductors and devices			
357.0	Underground conduit			
358.0	Underground conductors and devices			
359.0	Roads and trails			
354.0	Towers and fixtures			
355.0	Poles and fixtures			
356.0	Overhead conductors and devices			
357.0	Underground conduit			
358.0	Underground conductors and devices			
359.0	Roads and trails			
	Distribution plant:			
360.0	Land and land rights	902,202		
361.0	Structures and improvements			
362.0	Station equipment	18,879,775	2.20%	415,355
362.1	Supervisory control equipment	1,947,611	6.70%	130,490
362.2	Microwave system equipment	2,056,520	6.70%	137,787
362.223	Microwave sytem towers	1,354,847	3.00%	40,645
362.4	Owensboro fiber	919,512	4.00%	36,780
363.0	Storage battery equipment	-		
364.0	Poles, towers, and fixtures	69,679,825	4.20%	2,926,553
365.0	Overhead conductors and devices	49,418,898	3.40%	1,680,243
366.0	Underground conduit	14,166	2.20%	312
367.0	Underground conductors and devices	13,776,643	3.10%	427,076

Kenergy

2011 RATE APPLICATION

Depreciation Expenses
Modified March 30, 2011

Account Number	Item	(End of Test Year) Plant Account Balance	Depreciation Rate	Annual Depreciation
368.0	Transformers	30,314,848	2.90%	879,131
369.0	Services	23,145,990	3.80%	879,549
370.0	Meters	5,214,394	3.30%	172,075
370.1	AMI Meters	136,911	6.67%	9,132
371.0	Installations on customer premises	3,353,899	4.40%	147,573
372.0	Leased property on customer premises			
373.0	Street lighting and signal systems	790,335	3.80%	30,033
	Total Distribution Plant	221,906,375		$ 7,912,732
	General plant:			
389.0	Land and land rights	469,363		
390.0	Structures and improvements	7,304,939	2.00%	$ 146,128
391.0	Office furniture and equipment	459,505	6.00%	$ 27,570
391.1	Computer and related equipment	527,444	20.00%	$ 105,491
392.0	Transportation equipment	7,735,103	8.53%	$ 659,625
393.0	Stores equipment	168,992	4.80%	$ 8,112
394.0	Tools, shop, and garage equipment	855,229	4.80%	$ 41,051
395.0	Laboratory equipment	553,418	4.80%	$ 26,564
396.0	Power operated equipment	533,265	13.50%	$ 71,991
396.1	Power operated - right of way equipment	309,260	10.00%	$ 30,925
397.0	Communication equipment	1,899,741	6.50%	$ 123,491
398.0	Miscellaneous equipment	517,120	4.80%	$ 24,822
	Total General Plant	21,333,379		1,265,769

Kenergy Corp.
2011 rate application
Depreciation Adjustment - Distribution plant
Modified March 30,2011

Line No.	(a) Description	(b) Account Number	(c) Balance 6/30/2010	(d) Current Depreciation Rate	(e) Proforma Depreciation Current rates	(f) Proposed Depreciation rates	(g) Impact of change		
1	Land and Land Rights	360.000	$902,202	n/a	0				
2	Station	362.000	$18,879,775	2.2%	$415,355	1.9%	$ (56,639)		
3	Supervisory Control	362.100	$1,947,611	6.7%	$130,490	5.0%	$ (33,109)		
4	Microwave Equipment	362.200	$2,056,520	6.7%	$137,787	5.0%	$ (34,961)		
5	Microwave Towers	362.223	$1,354,847	3.0%	$40,645	2.8%	$ (2,710)		
6	Owensboro Fiber Loop	362.400	$919,512	4.0%	$36,780	4.0%	$ -		
7	Poles, Tower's, and Fixtures	364.000	$69,679,825	4.2%	$2,926,553	4.7%	$ 348,399		
8	Overhead Conductor's and Devices	365.000	$49,418,898	3.4%	$1,680,243	3.9%	$ 247,094		
9	Underground Conduit	366.000	$14,166	2.2%	$312	2.2%	$ -		
10	Underground Conductor and Devices	367.000	$13,776,642	3.1%	$427,076	3.1%	$ -		
11	Line Transformer's	368.000	$30,314,848	2.9%	$879,131	2.9%	$ -		
12	Services	369.000	$23,145,990	3.8%	$879,548	3.8%	$ -		
13	Meters	370.000	$5,214,394	3.3%	$172,075	5.0%	$ 88,645		
14	Meters-AMI	370.100	$136,911	6.67%	$9,132	6.7%	$ -		
15	Installation on Customer's Premises	371.000	$3,353,899	4.4%	$147,572	5.4%	$ 33,539		
16	Street Lighting	373.000	$790,335	3.8%	$30,033	3.8%	$ -		
17									
18	Total - Distribution Plant		$221,906,375		$7,912,732				
19									
20			Test year		$7,750,144				
21									
22		Adjustment - year end plant @ current rates			$162,588	Adjustment new rates	$ 590,258	Total Adjustment	$752,846
23									
24	Total - Distribution Plant		$221,906,375						
25	General plant accounts		$ 21,333,379						
26	account 302 franchises		$ 19,355						
27	Total utility plant per line 1 form 7		$243,259,109						

KENERGY CORP.
RESPONSE TO THE COMMISSION'S
SECOND DATA REQUEST FOR INFORMATION

2011 RATE APPLICATION

Item 29) Refer to Kenergy's response to Staff's First Request, Item 37, pages 2 and 3. Staff is unable to verify the amounts shown in the Annual Depreciation column. Confirm the amounts shown in this column are correct, or provide a corrected schedule.

Response) Item 28, pages 2 - 3 of 4, contains the above referenced information.

Witness) Steve Thompson