

DORSEY, KING, GRAY, NORMENT & HOPGOOD

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January 11, 2007

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JAN 12 2007

PUBLIC SERVICE  
COMMISSION

Ms. Elizabeth O'Donnell  
Public Service Commission  
211 Sower Boulevard  
Frankfort, Kentucky 40602

Re: Kenergy Corp.  
PSC Case 2006-00494

Dear Ms. O'Donnell:

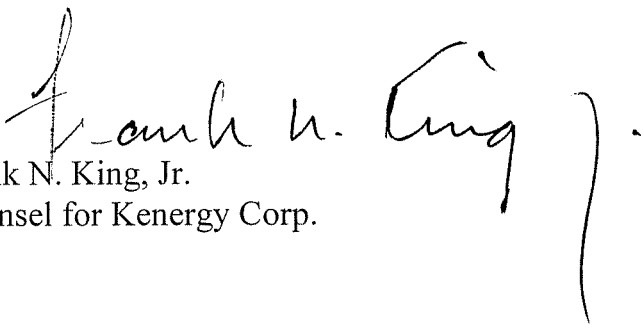
Enclosed for filing please find the original and seven (7) copies of Response of Kenergy Corp. to First Data Request of Commission Staff. If the Commission desires copies of the Response to be served on other jurisdictional electric distribution utilities, please provide the undersigned with a service list including the names and addresses of these utilities.

Your assistance in this matter is appreciated.

Very truly yours,

DORSEY, KING, GRAY, NORMENT & HOPGOOD

By

  
Frank N. King, Jr.  
Counsel for Kenergy Corp.

FNKJr/cds

COPY/w/encls.: Office of Rate Intervention  
Attorney General of Kentucky  
1024 Capital Center Drive  
Frankfort, Kentucky 40601

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**KENERGY CORP.  
 RESPONSE OF KENERGY CORP.  
 TO FIRST DATA REQUEST OF COMMISSION STAFF**

**CASE NO. 2006-00494**

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- Item 1)** Does utility management measure, monitor, or track distribution reliability?
- a. If so, describe the measures used and how they are calculated.
- b. If reliability is monitored, provide the results for the past 5 years for system wide reliability.

**Response a)** Yes. Kenergy monitors distribution reliability with *Institute of Electrical and Electronic Engineers (IEEE) Standard 1366 indices; System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and Customer Average Interruption Duration Index (CAIDI)*. These indices are calculated as follows:

- SAIFI: Total # of customer interruptions divided by the total # of customers served.
- SAIDI: Sum of all customer interruption durations divided by total # of customers served.
- CAIDI: Sum of all customer interruption durations divided by total # of customer interruptions or SAIDI/SAIFI

**Response b)**

	(1)	(2)	(3)	(2/1)	(3/1)	(3/2)
Year	Customers Served Year-Ending	Customer Interruptions	Customer Interruption Duration Minutes	SAIFI	SAIDI Minutes	CAIDI Minutes
2002	51,837	127,505	12,074,982	2.4597	232.9413	94.702
2003	52,464	123,594	10,874,359	2.3557	207.2727	87.987
2004	53,168	204,284	33,873,819	3.8422	637.1091	165.818
2005	53,819	114,967	8,661,719	2.1362	160.9417	75.3402
2006	54,252	180,582	35,502,060	3.3285	654.3917	196.6026

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2 Witness) Gerald Ford

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**Item 2)** Are any outages excluded from your reliability measurement? If so, what criteria are used to exclude outages?

**Response)** The table in response to Item 1b. contains all outages, but can be segmented by each specific cause code.

**Witness)** Gerald Ford



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**Item 3)** Does the utility differentiate between momentary and sustained outages?

a. What criteria are used to differentiate?

b. Is information about momentary interruptions recorded?

**Response a)** Kenergy does not consider a momentary interruption (breaker operation) an outage. Momentary interruptions are only recorded at the substation level. A system disturbance is considered sustained if its duration extends beyond the cycle of recloser operations.

**Response b)** Momentary outages on substation feeders are recorded through the Supervisory Control Data Acquisition (SCADA) system. Momentary outages are not recorded beyond the substation level.

**Witness)** Gerald Ford





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**Item 4)** At what level of detail does the utility record customer outages (individual customer, by re-closer, by circuit, by substation, etc.)?

**Response)** Kenergy records customer outages by re-closer, by circuit, and by substation. Individual customer outages are entered in the Outage Management System and information is retrieved as needed to address customer inquiries.

**Witness)** Gerald Ford



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**Item 5)** How does the utility detect that a customer is experiencing an outage?

**Response)** In addition to the customer calling into Kenergy's control center to report an outage, the SCADA system detects substation feeder interruptions and generates a computer data printout for the control center.

**Witness)** Gerald Ford



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**Item 6)** How does the utility know when a customer is restored?

**Response)** The line technician making the repairs contacts the control center when an outage is restored. The System Controller calls selected affected customers to confirm power restoration.

**Witness)** Gerald Ford



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**Item 7)** Are the causes of outages categorized and recorded? If they are, provide a list of the categories used.

**Response)** Yes. Kenergy uses the following cause code categories.

Cause Code	Description	Cause Code	Description
103	Conductor Failure (4 ACSR)	152	Guy Wire/Anchor (loose/broken)
104	Conductor Failure (2 ACSR)	153	Jumper (broken/loose)
105	Cold Weather	157	Customer's Problem
106	Ice Build Up (weight)	159	Prearranged (contractor conversion)
107	Major Storm	161	Pole Broken (wind)
108	Power Supply (Big Rivers)	162	Pole Broken (public)
110	Conductor Failure (UG Primary)	163	Public (tore wire down)
111	Conductor Failure (UG Secondary)	164	Public (damaged underground)
112	Conductor Failure (8-A)	165	Public (cut tree on line)
113	Conductor Failure (6-A)	167	Prearranged Maintenance
114	Conductor Failure (4-A)	168	Prearranged Construction
115	Conductor Failure (6-HD)	169	Right Of Way (contractors)
116	Conductor Failure (4-HD)	170	Right Of way (wind)
117	Conductor Failure (6-CU-TRI)	171	Right Of Way (ice/snow)
118	Conductor Failure (4-CU-TRI)	172	Right Of Way (off r/w)
119	Conductor Stranded	173	Right Of Way (on r/w)
120	Conductor (sleeve failure)	174	Transformer Failure (substation)
121	Conductor Down (HL clamp/conn.)	175	Transformer Failure (Cooper,McGraw)
122	Conductor (loose grd./connection)	175	Transformer Failure (overload)
123	Connection Bad (meter socket)	176	Transformer Failure (Howard)
123	Connection Bad (weatherhead)	177	Transformer Failure (Wagner)
124	Connection Bad (transformer)	178	Transformer Failure (UUS, Statewide)
126	Crossarm (broken/decay)	180	Transformer Failure (ABB, W'house)
133	Insulator Bad (suspension type)	181	Transformer Failure (Sieman, AC)
134	Insulator Bad (pin type)	182	Transformer Failure (Dowzer)
135	Lightning Arrestor Failure	183	Transformer Failure (Kuhlman)
136	Combination Unit Failure	184	Transformer Failure (AB Chance)
137	Equipment Failure (overhead)	185	Transformer Failure (Ermco)
138	Equipment Failure (underground)	186	Transformer Failure (Porter, Delta)
140	Fuse Blown (squirrel)	187	Transformer Failure (all other types)
141	Fuse Blown (bird)	189	Tie Wire Failure
142	Fuse Blown (animal)	190	Unknown
143	Fuse Blown (M5-10 lightning)	191	No Cause Found (windy conditions)
144	Fuse Blown (transformer lightning)	192	No Cause Found (wet conditions)
145	Fuse Failure (broken/decay)	193	No Cause Found (stormy weather)
146	Fuse Barrel (failure)	195	Other
148	Fire (equipment damage)	196	Vibration
149	Fire (house damage)	198	Wireholder (loose/broken, K10-K11)



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2   Witness)    Gerald Ford

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**Item 8)** Can the utility record outage information for each circuit in the system including for each customer outage:

- a. Length of each disruption?
- b. Number of customers affected by each disruption?
- c. Number of customers served by each circuit?
- d. Cause of each interruption?

**Response a)** Yes  
**Response b)** Yes  
**Response c)** Yes  
**Response d)** Yes

**Witness)** Gerald Ford



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2 **Item 9)** If the answer to any part of Item 8 is no, what would be required to enable the  
3 utility to collect this level of data?

4 a. Provide an estimated cost to obtain this level of detail.

5 b. Provide an estimated timeline to implement such upgrades.

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7 **Response a)** Not applicable.

8 **Response b)** Not applicable.

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10 **Witness)** Gerald Ford

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**Item 10)** Does the utility follow any type of standard (e.g., ANSI A300) for trimming trees in or near to the distribution right-of-way?

**Response)** Kenergy’s pruning activities are based on accepted arboricultural standards, including ANSI A300 – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices (Pruning), International Society of Arboriculture Best Management Practices, Utility Pruning of Trees – Special Companion Publication to the ANSI A300 Standard and Pruning Trees Near Electric Utility Lines, A Field Pocket Guide For Qualified Line-Clearance Tree Workers by Dr. Alex Shigo.

During the vendor procurement process, Kenergy states in the Request for Proposals (RFP) that the successful contractor will prune according to the ANSI A300 Standard.

**Witness)** Doug Hoyt





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**Item 11)** What criteria does the utility use to determine when vegetation maintenance or tree trimming is required?

**Response)** Kenergy engages in two types of vegetation management control activities, pruning and herbicide application. Pruning activities include routine circuit maintenance (vegetation management control activities performed on an entire circuit) and job orders and work orders (vegetation management control activities performed on a specific portion of a circuit identified by Kenergy through a Kenergy generated job order or work order). Work orders are generated when vegetation management control activities are required to be performed in conjunction with a specific electric system improvement project. Job orders are created as a result of a specific problem area, sometimes referred to as a “hot spot” where trees or limbs are interfering with a power line. These can involve a single tree or a more extensive line section. Both work orders and job orders are reactive vegetation management work. Routine circuit maintenance is a proactive vegetation management technique undertaken by Kenergy to prevent outages, thus improving customer reliability and to eliminate unsafe conditions.

Kenergy has developed a fixed-cycle vegetation management program that will result in routine circuit maintenance being performed on its approximate 5,300 miles of primary overhead line in a period not to exceed seven years. Outage statistics, including number of outages, duration of outages and SAIFI, along with personal observation by Kenergy personnel are used to determine the priority of need and subsequent cycle year for

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each of the 189 feeders on Kenergy's system. Personal observation includes re-growth rates and species composition. Each year, that plan is reviewed and compared against current statistics to determine if adjustments need to be made in the scope of work for the following year.

Appropriate herbicide is applied to each feeder in the year after routine circuit maintenance is performed.

**Witness)**      Doug Hoyt



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**Item 12)** Is the tree trimming performed by utility personnel or by contractor? If by contractor, describe the controls management uses to ensure trees are trimmed per utility requirements.

**Response)** All pruning activities performed on Kenergy's system are performed by contractors. Kenergy's established pruning specifications were a part of the Request for Proposals to procure the contractor and are embedded within the contract. Also contained in both documents is Kenergy's Quality Assurance (QA)/Quality Control (QC) procedures. When routine circuit maintenance is completed on a circuit, the contractor is responsible for inspecting the line to ensure compliance with Kenergy's specifications, after which they submit their Kenergy provided Quality Assurance Form certifying completion. Kenergy personnel inspects the line for compliance, completes the Quality Control Form and notifies the contractor of any deficiencies. The contractor has one week to correct deficiencies. Final approval is given after all corrected deficiencies are inspected.

**Witness)** Doug Hoyt



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**Item 13)** Is any portion of the utility system subject to local codes or ordinances regarding tree trimming or vegetation management?

- a. Which areas of the system are covered by local codes or ordinances?
- b. For each covered area, what do the local codes or ordinances require?

**Response a)** Not applicable.  
**Response b)** Not applicable.

**Witness)** Doug Hoyt



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2 **Item 14)** How often does the utility clear its distribution easements?

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4 **Response)** Beginning in 2005, Kenergy initiated a fixed-cycle vegetation management  
5 program that would result in routine circuit maintenance being performed on the  
6 approximately 5,300 miles of primary overhead line on its system in a period not to exceed  
7 seven years. In order to accomplish this, work is performed year-round.

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9 **Witness)** Doug Hoyt

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**Item 15)** How much has the utility spent on distribution easement clearing for each of the last 5 years? Include the cost per mile expended.

**Response)** Kenergy's total vegetation management expenses for 2001 – 2005 and estimated 2006 are as follows:

Year	Total VM Expenses	Contractor Herbicide Application Expenses	VM Expenses Less Herbicide Application
2001	\$1,342,837	*	\$1,342,837
2002	\$1,406,127	*	\$1,406,127
2003	\$1,489,568	\$137,760	\$1,351,808
2004	\$2,521,400	\$257,119	\$2,264,281
2005	\$3,651,823	\$255,840	\$3,395,983
2006	\$3,598,471 (est)	\$262,424	\$3,336,047

\* Kenergy personnel performed herbicide application prior to 2003. Herbicide application expenses were not separated from other pruning labor.

Year	Total Cost	Miles Treated	Cost Per Mile
2003	\$137,760	894	\$154
2004	\$257,119	944	\$272
2005	\$255,840	822	\$311
2006	\$262,424	1,484	\$177

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Routine Circuit Maintenance

Year	Total Cost	Miles Cleared	Cost Per Mile
2005	\$1,259,171*	536*	\$2,351
2006	\$1,867,328*	705*	\$2,649

\*System improvements, conductor replacement and hot spot pruning are not included in this number as data is not readily available.

Witness) Doug Hoyt



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**Item 16)** What annual amount of money is included in the current retail rates for distribution easement clearing?

**Response)** The amount of annual money included in PSC Case No. 2004-00446 for distribution easement clearing was \$1,911,617.17, which utilized a test year ending May 31, 2004. The amount requested in Case No. 2006-00369, which utilized a 2005 test year, was \$3,651,823. A settlement agreement will be filed in this proceeding on or before January 12, 2007 with a public hearing scheduled on January 23, 2007 to consider the reasonableness of the proposed settlement agreement. Under the proposed terms of the settlement agreement, the new rates would be effective March 1, 2007.

**Witness)** Steve Thompson