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PUBLIC SERVICE
COMMISSION

Ms. Stephanie L. Stumbo
Executive Director
Kentucky Public Service Commission
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Frankfort, KY 40602-0615

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July 10, 2008

RE: ***THE 2008 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY – Case No. 2008-00148***

Dear Ms. Stumbo:

Enclosed please find and accept for filing the original and seven (7) copies of the Response of Louisville Gas and Electric Company and Kentucky Utilities Company to the Commission Staff's First Data Request dated June 26, 2008, in the above referenced matter.

Should you have any questions concerning the enclosed, please contact me at your convenience.

Sincerely,

Rick E. Lovekamp

Enclosures

cc: Parties of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE 2008 JOINT INTEGRATED RESOURCE	)	
PLAN OF LOUISVILLE GAS AND ELECTRIC	)	CASE NO.
COMPANY AND KENTUCKY UTILITIES	)	2008-00148
COMPANY	)	

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY
TO THE FIRST DATA REQUEST
OF COMMISSION STAFF
DATED JUNE 26, 2008

FILED: JULY 10, 2008

VERIFICATION

STATE OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Charles A. Freibert Jr.,** being duly sworn, deposes and says that he is the Director, Regulated Trading & Dispatch for E.ON U.S. Services Inc., that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Charles A. Freibert, Jr.
CHARLES A. FREIBERT JR.

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of July, 2008.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:
Sept 20, 2010

VERIFICATION

STATE OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **John Wolfram**, being duly sworn, deposes and says that he is the Director, Customer Service & Marketing for E.ON U.S. Services Inc., that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

[signature]

JOHN WOLFRAM

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of July, 2008.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

VERIFICATION

STATE OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **J. Scott Cooke**, being duly sworn, deposes and says that he is the Manager, Generation Planning & Analysis for E.ON U.S. Services Inc., that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

J. Scott Cooke
J. SCOTT COOKE

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of July, 2008.

Victoria Harper (SEAL)
Notary Public

My Commission Expires:
Sept 20, 2010

VERIFICATION

STATE OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Irvin Hurst**, being duly sworn, deposes and says that he is the Manager, Energy Efficiency Operations for E.ON U.S. Services Inc., that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

I. Hurst
IRVIN HURST

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of July, 2008.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:
Sept 20, 2010

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to First Data Request of Commission Staff
Dated June 26, 2008

Case No. 2008-00148

Question No. 1

Witness: Charles A. Freibert Jr. / John Wolfram

Q-1. Refer to Volume I, Section 8 Resource Assessment pages 8, 69-70. Table 8(3)(d) shows that there are no existing or projected amounts of electric energy or generating capacity from cogeneration, self-generation, or technologies relying on renewable resources or other non-utility sources. If the Warner Lieberman Climate Change Bill (S.2191) or a similar bill had become law, these other sources of generation capacity and energy may have become important new resources.

a. Provide an explanation of how the Companies would become aware of new generation projects, and are the Companies actively researching potential sources of low carbon emitting generation?

b. Are the companies aware of any non-utility generation taking place in their service territories? If so, provide a list of all non-utility generation taking place within their service territories.

c. Are the Companies aware of any industries that have the potential for self generation or cogeneration that have not yet been developed? If so, are there any plans to approach these other companies regarding the possible development of such generation?

d. In Kentucky, there are several small landfill gas projects. Have the Companies considered pursuing similar projects or other relatively small-scale generation projects as future potential sources of power?

(1) If so, provide a list of projects that have been considered, but were not sufficiently viable to the point of being places in Table 8(3)(d).

(2) If not, provide an explanation as to why the pursuit of multiple small generation projects (landfill gas, biomass, hydro or otherwise) is not a viable resource option.

e. Are the Companies opposed to the idea of pursuing individually small-scale low carbon emitting generation projects or working with other companies in either an advisory capacity or as a business partner to develop potential new supplies of low carbon emitting generation?

A-1. a. The Companies become aware of new generation projects through research and participation in trade associations, solicitations, interface with account executives, and project developers. The Companies have engaged in multiple efforts to investigate and secure low-cost and low-carbon generation resources. In 2007 the Companies issued two requests for proposals (RFP's) for peaking (including generation from renewable fuel sources) and renewable generation resources. As a result, of these RFP's the Companies have executed a contract for the summers of 2008 and 2009 for 165 MW of peaking capacity with Dynegy.

Discussions are underway with two wind project developers to fully understand the costs and benefits of their wind energy proposals. Discussions are also ongoing with a landfill owner regarding the purchase of landfill gas for use in electric generation. Each of these organizations responded to the renewable RFP. If any of these discussions mature into an actionable and beneficial proposal the Companies will make any necessary filings in 2009.

In addition, the Companies have conducted studies of self-build green generation. Wind generation development potential in Kentucky was analyzed in 2007. Landfill gas generation is currently being analyzed. An expansion of the Ohio Falls Hydro Station and PV solar will be evaluated before the end of 2008.

The Companies are engaged in other research and development projects that are focused on reducing greenhouse gases. In April 2006, the University of Kentucky's Center for Applied Energy Research received a three-year, $1.5 million commitment from E.ON U.S., the parent company of LG&E and KU, to study technology to reduce greenhouse gases. In October 2006, E.ON U.S., announced that it committed $25 million to join the FutureGen Alliance. The Companies are also charter members of the Electric Power Research Institute's "Coal Fleet for Tomorrow" program, which is focused on making a portfolio of advanced coal technologies more accessible and affordable for power producers and society.

Recently, Kentucky Governor Steve Beshear announced that the state is partnering with the newly created Western Kentucky Carbon Storage Foundation to advance the science of long-term carbon storage opportunities. E.ON U.S., Peabody Energy and ConocoPhillips formed the non-profit

Foundation to work with the Kentucky Geological Survey in a project that includes drilling a well to test geological formations for CO_2 storage capabilities at a site in Hancock County.

b. The Companies are aware of approximately 160 non-utility generators in their service territories. The size of the generation ranges from less than 50 KVA to 14 MW. It is typical for customers to have their generators located in multiple sites (See Exhibit I) with a few having one generation source. It is also typical for this generation to be specifically identified as emergency back-up generation and designed for internal use, thus not allowing for connection to the Companies grid. The list of customer-owned generation should not be considered an exhaustive list of non-utility generation since the company does not specifically track this information nor is it required to obtain this information from the customer.

Due to their small size, these generators have high production costs. In addition, the cost to install remote control devices, complex switching at customers site, fuel service, and providing maintenance adds to the costs of utilizing these small generators. Thus, small generators are not of economic value in serving the LG&E/KU native load.

Dynegy owns three 165 MW natural gas-fired combustion turbines at the Bluegrass Generating Station, which is located in the LG&E service territory. The Companies have executed a contract for the summers of 2008 and 2009 for 165 MW of peaking capacity with Dynegy.

c. The Companies have assisted several industrial customers in evaluating their potential for self- or co-generation in the past. Each of these investigations identified one or more concerns which prevented construction of the project. In general, the paper and process industries have the best potential for self- or co-generation. The Companies do not believe additional communication with industrial customers is likely to lead to viable generation projects, but the Companies remain open to future discussions.

d. The Companies have considered landfill and other similar projects, as well as small-scale generation projects generally, as potential sources of generation for the Companies.

(1) The Companies are currently discussing with a landfill owner the possible purchase of landfill gas for use in electric generation. These discussions concern three landfills in Kentucky with the potential to generate 6 to 10 MW combined. The Companies have discussed a similar arrangement with another landfill owner, and are awaiting a response from the landfill owner to continue the discussions.

If any of these discussions mature into an actionable and beneficial proposal, the Companies will make any necessary filings with the Commission in 2009.

(2) Not applicable.

e. No. As the Companies' responses to the other parts of this Data Request demonstrate, the Companies have been and continue to be proactive in seeking out small-scale and low-carbon generation resources, constrained by the need for such resources to be prudent investments. Therefore, the Companies are not opposed to pursuing individually small-scale low carbon emitting generation projects or working with other companies in either an advisory capacity or as a business partner to develop potential new supplies of low carbon emitting generation.

Customer-Owned Generation

	Capacity	Notes
1	1,500 KW	4 units of various sizes
2	1,350 KW	1-250, 1-300, 1-400, 1-250, 1-125
3	10 MW	
4	5.5 MW	
5	14 MW	
6	500kw or 625kva ability	
7	500kw or 625 kva	
8	350 kva	
9	125 kva	
10	50kw	
11	2250 kVA or 1800 kW	3 generators 750 kVA (600 kW) each
12	900 kVA (720 kW)	
13	1500 kVA or 1200 kW	2 generators 750 kVA (600 kW) each
14	1,875 kVA (1,500 kW)	
15	500 kVA (400 kW)	
16	2500 kVA or 2000 kW	2 generators 1250 kVA (1,000 kW) each
17	7000 KW	5 generators 1,750 kVA (1,400 kW) each
18	375KVA	
19	3,600KVA	4 generators 900KVA each
20	6,750KVA	3 generators 2250KVA each
21	750KVA	
22	1,562KVA	
23	675KVA	3 generators various size
24	2MW	
25	6.75MW	3 generators 2.25 MW each
26	1.6 MW	
27	800 KW	
28	900 kw	one 600 kw and one 300 kw
29	1020 kw	600kw; 300kw; 60kw; 60kw
30	2050 kw	(2) 400 KW Onan Diesel Gen Set; (1) 1250 KW Cat Diesel Gen Set
31	1600 kw	(1) 600 KW Cat Diesel Gen Set; (1) 1000 KW Cat Diesel Gen Set
32	1200 kw	(2) 600 KW Cat Diesel Gen Set
33	1125 kw	(1) 175 KW Cat Diesel Gen Set; (1) 350 KW Cat Diesel Gen Set; (1) 600 KW Cat Diesel Gen Set
34	88 kw	(1) 88 KW Olympia Diesel Gen Set
35	175 KW, 219 KVA	Onan, Diesel
36	175 KW, 219 KVA	Onan, Diesel
37	175 KW, 219 KVA	Onan, Diesel
38	48 KW, 60 KVA	Kohler, Diesel
39	100 KW, 125 KVA	Olympian, Diesel
40	250 KW, 313 KVA	Kohler, Diesel
41	150 KW, 188 KVA	Kohler, Diesel
42	2250 KW, 2812 KVA	Cat, Diesel
43	2250 KW, 2812 KVA	Cat, Diesel
44	500 KW, 625 KVA	Cat, Diesel
45	400 KW, 500 KVA	Cat, Diesel

	Capacity	Notes
46	7.5 MW	
47	1 MW	
48	1.5 MW	
49	500 KW	
50	5 MW	One meg at each store, total of 5 meg
51		trailer units that travel with a meg per trailer
52		trailer units that travel with 500 kVa units
53	1 MW	about one meg total plus numerous very small portable units
54	1 MW	about two megs total plus numerous very small portable units
55	6800 KW	Ten generators
56	1000 KW	
57	400kw and 125kw	
58	250 KW	
59	100 KW	
60	30 KW	
61	62 KW	
62	100 KW	
63	30 KW	
64	200 KW	
65	500 KW	
66	400 KW	
67	30 KW	
68	130 KW	
69	100 KW	
70	60 KW	
71	125 KW	
72	100 KW and 160 KW	
73	600 KW	
74	25 KW	
75	100 KW	
76	900 KW	
77	230 KW	
78	250 KW	
79	100 KW	
80	125 KW	
81	60 KW	
82	800 KW	
83	1000 KW	
84	13000 KW	(1) 8000 KW, (2) 5000 KW
85	5000 KW	
86	1500 KW	
87	200 KW	Diesel CAT
88	230 KW	Kohler diesel generator
89	250 KW	CAT Diesel unit
90	30 KW	Kohler diesel unit
91	15 KW	
92	43.8 KVA/35 KW	277/480/3 Voltage/Phase - Natural Gas

	Capacity	Notes
93	49 KVA/39 KW	120/208/3 Voltage/Phase - Natural Gas
94	62.5 KVA/50 KW	120/208/3 Voltage/Phase - Natural Gas
95	81.3 KVA/65 KW	120/208/3 Voltage/Phase - Natural Gas
96	81.3 KVA/65 KW	277/480/3 Voltage/Phase - Natural Gas
97	38 KVA/30 KW	120/208/3 Voltage/Phase - Natural Gas
98	156.25 KVA/125 KW	120/208/3 Voltage/Phase - Natural Gas
99	62.5 KVA/50 KW	120/208/3 Voltage/Phase - Natural Gas
100	75 KVA/60 KW	120/208/3 Voltage/Phase - Natural Gas
101	38 KVA/30 KW	120/208/3 Voltage/Phase - Natural Gas
102	49 KVA/39 KW	277/480/3 Voltage/Phase - Natural Gas
103	63 KVA/50 KW	277/480/3 Voltage/Phase - Natural Gas
104	37.5 KVA/30 KW	277/480/3 Voltage/Phase - Natural Gas
105	44 KVA/35 KW	120/208/3 Voltage/Phase - Natural Gas
106	75 KVA/60 KW	277/480/3 Voltage/Phase - Natural Gas
107	125 KVA/100 KW	277/480/3 Voltage/Phase - Natural Gas
108	69 KVA/55 KW	277/480/3 Voltage/Phase - Natural Gas
109	49 KVA/39 KW	120/208/3 Voltage/Phase - Natural Gas
110	125 KVA/100 KW	277/480/3 Voltage/Phase - Natural Gas
111	38 KVA/30 KW	120/208/3 Voltage/Phase - Natural Gas
112	56 KVA/45 KW	120/208/3 Voltage/Phase - Natural Gas
113	93.75 KVA/75 KW	277/480/3 Voltage/Phase - Natural Gas
114	75 KVA/80 KW	120/208/3 Voltage/Phase - Natural Gas
115	69 KVA/55 KW	277/480/3 Voltage/Phase - Natural Gas
116	38 KVA/30 KW	120/208/3 Voltage/Phase - Natural Gas
117	81.3 KVA/65 KW	277/480/3 Voltage/Phase - Natural Gas
118	106 KVA/85 KW	277/480/3 Voltage/Phase - Natural Gas
119	37.5 KVA/30 KW	120/208/3 Voltage/Phase - Natural Gas
120	81.3 KVA/65 KW	120/208 Voltage/Phase - Natural Gas
121	52.5 KVA/42 KW	120/208/3 Voltage/Phase - Natural Gas
122	56.25 KVA/45 KW	277/480/3 Voltage/Phase - Natural Gas
123	56.25 KVA/45 KW	120/208/3 Voltage/Phase - Natural Gas
124	56.25 KVA/45 KW	277/480/3 Voltage/Phase - Natural Gas
125	75 KVA/60 KW	277/480/3 Voltage/Phase - Natural Gas
126	31.25 KVA/25 KW	277/480/3 Voltage/Phase - Natural Gas
127	63 KVA/50 KW	120/208/3 Voltage/Phase - Natural Gas
128	125 KVA/100 KW	277/480/3 Voltage/Phase - Natural Gas
129	56.25 KVA/45 KW	120/208/3 Voltage/Phase - Natural Gas
130	37.5 KVA/30 KW	120/208/3 Voltage/Phase - Natural Gas
131	81.3 KVA/65 KW	277/480/3 Voltage/Phase - Natural Gas
132	75 KVA/60 KW	120/208/3 Voltage/Phase - Natural Gas
133	75 KVA/60 KW	120/208/3 Voltage/Phase - Natural Gas
134	56 KVA/45 KW	120/208/3 Voltage/Phase - Natural Gas
135	43.8 KVA/35 KW	277/480/3 Voltage/Phase - Natural Gas
136	75 KVA/60 KW	120/208/3 Voltage/Phase - Natural Gas
137	43.8 KVA/35 KW	277/480/3 Voltage/Phase - Natural Gas
138	37.5 KVA/30 KW	277/480/3 Voltage/Phase - Natural Gas
139	75 KVA/60 KW	277/480/3 Voltage/Phase - Natural Gas
140	56.25 KVA/45 KW	120/208/3 Voltage/Phase - Natural Gas
141	81.3 KVA/65 KW	277/480/3 Voltage/Phase - Natural Gas

	Capacity	Notes
142	125 KVA/100 KW	277/480/3 Voltage/Phase - Natural Gas
143	56.25 KVA/45 KW	120/208/3 Voltage/Phase - Natural Gas
144	143.75 KVA/115 KW	120/208/3 Voltage/Phase - Natural Gas
145	56.25 KVA/45 KW	120/208/3 Voltage/Phase - Natural Gas
146	69 KVA/55 KW	120/208/3 Voltage/Phase - Natural Gas
147	69 KVA/55 KW	277/480/3 Voltage/Phase - Natural Gas
148	75 KVA/60 KW	120/208/3 Voltage/Phase - Natural Gas
149	37.5 KVA/30 KW	120/208/3 Voltage/Phase - Natural Gas
150	100 KVA/80 KW	277/480/3 Voltage/Phase - Natural Gas
151	56.25 KVA/45 KW	120/208/3 Voltage/Phase - Natural Gas
152	52.5 KVA/42 KW	120/208/3 Voltage/Phase - Natural Gas
153	50 KVA/40 KW	120/208/3 Voltage/Phase - Natural Gas
154	49 KVA/39 KW	120/208/3 Voltage/Phase - Natural Gas
155	69 KVA/55 KW	120/208/3 Voltage/Phase - Natural Gas
156	113 KVA/90 KW	277/480/3 Voltage/Phase - Natural Gas
157	37.5 KVA/30 KW	120/208/3 Voltage/Phase - Natural Gas
158	75 KVA/60 KW	277/480/3 Voltage/Phase - Natural Gas
159	52.5 KVA/42 KW	120/208/3 Voltage/Phase - Natural Gas
160	69 KVA/55 KW	277/480/3 Voltage/Phase - Natural Gas
161	63 KVA/50 KW	277/480/3 Voltage/Phase - Natural Gas

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to First Data Request of Commission Staff
Dated June 26, 2008

Case No. 2008-00148

Question No. 2

Witness: J. Scott Cooke

Q-2. Refer to Volume I, Section 8 Resource Assessment Table 8(4), Table 8(4)-1, and Table 8(4)(a)-2, pp. 8, 84-87.

a. Provide a discussion and documentation supporting the choice of constructing a 475 MW combined cycle combustion turbine in 2015 and in 2019. What were the generation options that were not selected and why?

b. Does the potential for future carbon capture legislation play any part in the analysis regarding the selection of specific generation technology? If so, explain how the Companies are integrating the potential costs of carbon capture and sequestration into their resource assessment analyses.

c. Currently, there appear to be no plans to retire any coal generation units from the coal generation fleet. If the Warner Lieberman Climate Change Bill (S.2191) or some similar form of carbon capture and sequestration law were to be enacted, then:

(1) Provide an explanation of how this would affect the older coal generation units in the fleet and whether this would lead to the retirement of the units.

(2) Given the current state of carbon capture and sequestration, provide a discussion of which units would be able to be fitted with the necessary equipment to capture and store carbon.

A-2. a. The Companies plan calls for a combined cycle unit to be constructed at a Greenfield site in 2015 and 2019, and a Greenfield combustion turbine in 2022. This plan is supported by eleven sensitivities to key assumptions including DSM performance, load forecast, unit retirements, CO_2 regulation, combined cycle operation, natural gas prices, and coal construction costs.

The Optimal Expansion Plan report in Volume III provides more detail into these sensitivities and covers how the combined cycle combustion turbine was selected over the other choices from the options screened in the Supply-Side Analysis. Please see the Supply-Side Analysis report in Volume III, which addresses the generation options the Companies considered and the reasons the Companies did not select certain options. Section 4 of the Supply-Side Analysis provides a description of the over 50 generation options that were considered.

b. The Companies have included in the Analysis of Supply-Side Technology Alternatives report in Volume III an Alternative Analysis with CO_2 Impact. The Companies performed the Alternative Analysis to evaluate the impact of CO_2 legislation on the outcome of the screening analysis. The Alternative Analysis contained the same sensitivities (variability of capital cost, heat rate, and fuel cost) as were in the base case analysis. Also, the Companies included a CO_2 regulation sensitivity in the Optimal Expansion Plan Analysis in Volume III that concluded, based upon the assumed CO_2 emission allowance price, that the CO_2 regulation would not impact the expansion plan but would only act as a tax.

c.

(1) The Lieberman-Warner bill (S.2191) proposes a cap-and-trade program that would require significant reductions in greenhouse gas emissions from coal-fired generating units and other emissions sources (i.e., reductions from a 2006 baseline of 7% in 2012, 39% in 2030, and 72% in 2050). Though it appears that the bill will not advance in the current Congress, the next Congress will likely take up similar legislation. In general, such legislation would favor low-carbon technologies such as coal-fired generation with carbon capture and storage (CCS) capability, renewable energy, nuclear power, and lower-carbon fuels such as natural gas.

The exact impact of such legislation on the Companies' existing coal-fired generation will depend on factors including future cost of emission allowances, availability of offsets, feasibility of retrofitting CCS technology on existing units, the success of energy efficiency programs, and cost of competing lower carbon fuels such as natural gas. U.S. EPA and U.S. DOE have projected that the Lieberman-Warner bill or similar legislation could potentially result in retirement of some existing coal-fired generation. The Companies believe that, under certain regulatory scenarios, retirement of some coal-fired units could potentially be considered as an element of future compliance plans, with smaller and less efficient units at the greatest risk of retirement.

The substantial uncertainty regarding provisions of any future greenhouse gas legislation and prevailing future market conditions make it impossible for the Companies to identify specific generating units that may potentially be subject to retirement.

(2) At present, CCS technologies are not utilized by power generation facilities and current technologies are not considered to be cost-effective for such applications. EPRI, CAER, U.S. DOE, and others are conducting research on a variety of CCS technologies that may potentially be suitable for utility-scale applications in the future. However, CCS technologies are not expected to be commercially available for the power generation industry until 2020 or later. The feasibility of retrofitting CCS technologies to the Companies' exiting generating units will depend on a variety of factors including cost, physical space constraints, parasitic load demands, and other engineering factors associated with the specific CCS technologies that are ultimately deployed. Due to the early stage of current CCS research and development efforts, the Companies are unable to identify specific generating units for which future retrofits of CCS technology will be feasible.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to First Data Request of Commission Staff
Dated June 26, 2008

Case No. 2008-00148

Question No. 3

Witness: Irvin Hurst

Q-3. Refer to Volume III, DSM Screening Analysis, pp. 6-9, and Exhibit DSM:

a. For each of the DSM programs listed on pp. 6-9, provide a detailed explanation of how the estimated annual kWh reductions are calculated.

b. For each of the DSM programs listed on pp. 6-9, provide a detailed explanation of how the actual kWh reduced will be calculated and verified.

c. For each of the DSM programs listed on pp. 6-9, explain whether KU and LG&E personnel or third party vendors will be used to verify results.

A-3. a. The Company estimated total kWh reductions for each program by multiplying the planned number of participants (or measures) times an expected kWh reduction per participant (or measure). A primary source used to determine expected kWh per participant ("engineering estimate") was the Company's independent evaluation contractor who was asked to provide estimates for average-size homes and businesses based upon their evaluation of similar programs at other utilities. Additional sources include the Energy Star web site, manufacturers' web sites, equipment retailers' web sites and discussions with trade associations, consultants, and other utilities' staff. The expected kWh per measure utilized for the IRP analysis is a high level estimate that will be refined and evaluated in significantly greater detail in developing the cost benefit analysis that will be submitted with the filing when the Company requests the Commission to approve the programs for implementation.

The average kWh per measure utilized in the IRP analysis is shown for each program below:

- **Duct Evaluation & Sealing (Residential)**
  Assume annual 1122 kWh average savings per participant for homes with heat pumps.
  Assume annual 357 kWh average savings per participant for homes with gas heat.

  Total annual kWh savings were developed by multiplying the number of expected participants times the expected average savings per participant. Please see Volume III, Exhibit DSM-6, page 10 of 15 for expected annual participation.

- **Duct Evaluation & Sealing (Commercial)**
  Assume annual 3398 kWh savings per participant for businesses with heat pumps.
  Assume annual 2303 kWh savings per participant for businesses with gas heat.

  Total annual kWh savings were developed by multiplying the number of expected participants times the expected savings per participant. Please see Volume III, Exhibit DSM-6, page 3 of 15 for expected annual participation.

- **Geothermal Heat Pump (Commercial New Construction)**
  Assume annual savings of 22,457 (4,491 per ton) kWh on installation of a 5 ton geothermal heat pump compared to an air source heat pump.

  Total annual kWh savings were developed by multiplying the number of expected participants times the expected savings per participant. Please see Volume III, Exhibit DSM-6, page 14 of 15 for expected annual participation.

- **Window Shading & Films (Residential)**
  Assume average participant installs 150 square feet of window film.

  Assume each residence with a heat pump achieves annual savings of 444 kWh.

  Assume each residence with AC and gas heat achieves annual savings of 885 kWh.

Total annual kWh savings were developed by multiplying the number of expected participants times the expected savings per participant. Please see Volume III, Exhibit DSM-6, page 7 of 15 for expected annual participation.

- **High Efficiency Motors (Commercial)**
  Assume 50 HP open drip high efficiency motor yields annual savings of 2,700 kWh compared to a standard efficiency motor with the same horsepower.

  Assume 50 HP closed drip high efficiency motor yields annual savings of 2,500 kWh compared to a standard efficiency motor with the same horsepower.

  Total annual kWh savings were developed by multiplying the number of expected motors times the expected savings per motor. Please see Volume III, Exhibit DSM-6, page 4 of 15 for expected annual participation.

- **Responsive Pricing/Smart Metering/Energy Use Display (Residential)**
  Assume each participant with a heat pump will achieve annual savings of 1,100 kWh.

  Assume each participant with gas heat and AC will achieve annual savings of 750 kWh.

  Total annual kWh savings were developed by multiplying the number of expected participants times the expected savings per participant. Please see Volume III, Exhibit DSM-6, page 1 of 15 for expected annual participation.

- **Refrigeration Optimization (Commercial)**
  Assume each optimized refrigeration unit will yield annual savings of 28,991 kWh.

  Total annual kWh savings were developed by multiplying the number of expected refrigeration units times the expected savings per refrigeration unit. Please see Volume III, Exhibit DSM-6, page 9 of 15 for expected annual participation.

- **Removal of Second Refrigerator (Residential)**
  Assume each removed refrigerator yields annual savings of 1,310 kWh.

  Total annual kWh savings were developed by multiplying the number of expected refrigerators removed times the expected savings per refrigerator. Please see Volume III, Exhibit DSM-6, page 5 of 15 for expected annual participation.

- **Energy Management System (Commercial)**
  Assume installing an energy management system on a 10,000 square foot building will yield annual savings of 4,400 kWh.

  Total annual kWh savings were developed by multiplying the number of expected participants times the expected savings per participant. Please see Volume III, Exhibit DSM-6, page 11 of 15 for expected annual participation.

- **High Efficiency Heat Pump (replacing resistive heat) (Commercial)**
  Assume replacing resistive heat and a 5 ton heat, 10 SEER AC unit with a high efficiency heat pump will yield annual savings of 14,040 kWh.

  Total annual kWh savings were developed by multiplying the number of expected participants times the expected savings per participant. Please see Volume III, Exhibit DSM-6, page 13 of 15 for expected annual participation.

- **Heat Pump Water Heater – Restaurant & Laundries (Commercial)**
  Assume replacing 1,200 gallons per day (or 120 GPH) capacity resistance hot water heater with a like size heat pump water heater will yield annual savings of 66,430 kWh.

  Total annual kWh savings were developed by multiplying the number of expected water heater replacements times the expected savings per replacement. Please see Volume III, Exhibit DSM-6, page 8 of 15 for expected annual replacements.

- **Refrigeration Case Covers (Commercial)**
  Assume each participating store installs 20 linear feet of refrigeration case covers on open air units yielding annual savings of 9,060 kWh per store.

Total annual kWh savings were developed by multiplying the expected number of participating stores times the expected savings per store. Please see Volume III, Exhibit DSM-6, page 6 of 15 for expected number of stores participating annually.

b. The Companies will estimate the actual kWh reduction for each program by multiplying the actual number of participants (or measures) times the "engineering estimate" for each participant (or measure). Engineering estimates will be verified through a billing analysis or actual measurement (as appropriate) on a statistically representative sampling of participants which will be performed by an independent evaluation contractor as described in the answer to part c. below. All parties to the Companies' recent DSM filing (Case No. 2007-00319) agreed in the WeCare settlement agreement that this methodology is a reasonable and appropriate means of evaluating energy efficiency measures.

c. Results for each program will be determined through a third party independent contractor. The evaluation contractor will perform an impact and process evaluation to determine energy and demand savings, customer response and satisfaction, recommendations for changes and improvement, and overall effectiveness of the program. The Companies will utilize evaluation data and actual participation rates to provide an accurate estimation of energy and demand impacts.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to First Data Request of Commission Staff
Dated June 26, 2008

Case No. 2008-00148

Question No. 4

Witness: Irvin Hurst

Q-4. Refer to Volume III, DSM Screening Analysis, pp. 6-9, and Exhibit DSM-5 and the Aggressive Green Scenario Section.

a. Given the assumptions made in the Aggressive Green Scenario Section, explain whether these higher costs would alter any of the cost benefit tests for existing or potential DSM programs, including a more aggressive expansion of existing DSM programs.

b. Explain how the assumptions regarding the potential prices of CO_2 specifically affect the cost benefit tests for the DSM programs.

A-4.

a. The Aggressive Green Scenario assumes that customers seek out and purchase the most energy efficient technology available regardless of cost. If this situation actually existed, all DSM programs with the exception of those designed for load shifting would likely be discontinued as participants would become free riders. The costs would drive no benefits as the customers would be implementing the technology anyway.

Load shifting programs such as the Demand Conservation Program currently operated by the Companies and the Responsive Pricing/Smart Metering/Energy Use Display described in the DSM Screening Analysis would continue to deliver benefits; however, the benefits would be reduced as the equipment being controlled to shift load would now be more efficient.

b. Increased prices related to CO_2 could increase the cost of building generation capacity, might require older units to be replaced, additional generation O&M expenses, and the purchase of emission allowances. The result could be higher avoided and marginal costs, which could generate a more positive benefit-to-cost ratio on the California Tests, which are utilized to evaluate DSM programs.