LG&E Energy Corp LLC*
220 West Main Street (40202)
P.O. Box 32030
Louisville, Kentucky 40232

March 1, 2004

Mr. Thomas Dorman, Executive Director
Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40601

RECEIVED
MAR 0 1 2004
PUBLIC SERVICE COMMISSION

Re: ***A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION CAPACITY AND TRANSMISSION SYSTEM - ADM. CASE NO. 387***

Dear Mr. Dorman:

Pursuant to Appendix G of the Commission's Order dated December 20, 2001 in the above cited case, enclosed are an original and five (5) copies of the 2003 Annual Resource Assessment Filing of Kentucky Utilities Company.

Also filed herewith is a Petition for Confidential Protection regarding certain information provided in response to Item No. 11.

Very truly yours,

John Wolfram
Manager, Regulatory Affairs

Enclosures

A SUBSIDIARY OF LG&E ENERGY

Note: Effective December 30, 2003, LG&E Energy LLC, a Kentucky limited liability company, was the successor by assignment and subsequent merger of all of the assets and liabilities of LG&E Energy Corp., a Kentucky Corporation.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED
MAR 0 1 2004
PUBLIC SERVICE COMMISSION

In the Matter of:

A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION CAPACITY AND TRANSMISSION SYSTEM	)))	**ADMINISTRATIVE CASE NO. 387**

PETITION OF
KENTUCKY UTILITIES COMPANY
FOR CONFIDENTIAL PROTECTION

Kentucky Utilities Company ("KU"), by counsel, petitions the Kentucky Public Service Commission ("Commission") pursuant to 807 KAR 5:001 Section 7 to grant confidential protection to certain information filed pursuant to Appendix G of the Commission's Order of December 20, 2001.

In support of this petition, KU states as follows:

1. On December 20, 2001, the Commission issued an Order with its findings following an investigation and review of the adequacy of Kentucky's generation capacity and transmission system. In an effort to continue monitoring these issues, the Commission ordered Kentucky's six major jurisdictional electric utilities to file certain planning-related information, as defined in Appendix G to the Commission's December 20, 2001 Order, by March 1st of each year and by July 1st of 2002. In Item No. 11, the Commission ordered KU and the other jurisdictional electric utilities to provide information concerning scheduled outages or retirements of generating capacity.

2. In connection with the information provided in response to Item No. 11, the Commission has ordered KU to provide details of scheduled outages or retirements of generating capacity for current year and the following four years. KU is requesting confidential protection of the entire maintenance schedule. The information contained in this response and for which KU is seeking confidential protection is identical in nature to that provided to the Commission in response to the Commission's requests for information in Case No. 2000-497 and previously in this proceeding. The Commission granted confidential protection to KU's planned maintenance schedule for each of KU's generating units. This information would allow competitors to KU to know when KU's generating plants will be down for maintenance and thus know a crucial input into KU's generating costs and need for power and energy during those periods. The commercial risk of the disclosure of this information is that potential suppliers will be able to manipulate the price of power bid to KU in order to maximize their revenues.

3. KRS 61.878(1)(c) protects commercial information, generally recognized as confidential or proprietary, if its public disclosure would cause competitive injury to the disclosing entity. Competitive injury occurs when disclosure of the information would give competitors an unfair business advantage. The attached information contains such competitive and proprietary information, and is therefore being submitted with a request for confidential treatment.

4. The information sought to be protected was developed internally by KU personnel. The information is not on file with the Federal Energy Regulatory Commission, the Securities and Exchange Commission or other public agencies, and is not available from any commercial or other source outside of KU. Distribution of the information within KU is limited to those employees who have a business reason to have access to the information.

5. The information described in Paragraph 2 above is confidential and proprietary information which should not be disclosed in the public record. Disclosure of this information would provide unfair commercial advantages to KU's competitors in the wholesale market for bulk and off-system power sales. The passage of the Energy Policy Act has brought extensive competition to the electric wholesale market and introduced numerous new marketers, brokers, and clearinghouses, and many new sources of non-utility generation of power. The change in federal law has caused electric utilities to file nondiscriminatory open-access transmission tariffs and applications for approval of market-based wholesale power rates with the Federal Energy Regulatory Commission. The FERC has authorized utilities, including KU, to charge market-based prices for wholesale power transactions and approved open-access transmission services tariffs. See Kentucky Utilities Company, 71 FERC Par. 61,250 (May 31, 1995). All of these regulatory developments and changes in the law have created a robust and competitive wholesale market for bulk and off-system power sales.

6. KU's information regarding monthly coincident peak off-system demands, base case and high case off-system demand and energy forecasts, and scheduled outages or retirements of generation capacity constitutes information that is generally recognized as confidential. This information must remain confidential if the wholesale power market is to remain competitive and KU is to continue to compete for wholesale sales and purchase wholesale power at competitive prices. Disclosure of this information could provide suppliers with KU's expectations about the price of supplies in the future and would allow suppliers to take advantage of KU's solicitations by increasing their bids to the maximum extent possible, thereby causing higher prices for KU's customers, and would give commercial advantages to KU's competitors.

7. The information provided in response to Item No. 11 of Appendix G to the Commission's December 20, 2001 Order demonstrates on its face that it merits confidential protection. If the Commission disagrees, however, it must hold an evidentiary hearing to protect the due process rights of KU and supply the Commission with a complete record to enable it to reach a decision with regard to this matter. Utility Regulatory Commission v. Kentucky Water Service Company, Inc., Ky. App., 642 S.W.2d 591, 592-94 (1982).

8. KU does not object to disclosure of the confidential information, pursuant to a protective agreement, to intervenors with a legitimate interest in reviewing the confidential information for the purpose of assisting the Commission's review in this proceeding.

9. In accordance with the provisions of 807 KAR 5:001(7), KU is filing with the Commission one (1) set of the confidential information provided in response to Item No. 11 of Appendix G to the Commission's December 20, 2001 Order with the information highlighted and marked confidential and ten (10) sets of the response without the confidential information.

WHEREFORE, Kentucky Utilities Company respectfully requests that the Commission grant confidential protection for the information at issue, or schedule an evidentiary hearing on all factual issues while maintaining the confidentiality of the information pending the outcome of the hearing.

Dated: March 1, 2004

Respectfully submitted,

Linda S. Portasik

Linda S. Portasik
Senior Corporate Attorney
LG&E Energy Corporation
220 West Main Street
Louisville, Kentucky 40202

Counsel for
Kentucky Utilities Company

KENTUCKY UTILITIES COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING
PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER
DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387
FILED MARCH 1, 2004

ITEM NO. 11

RESPONDENT: Robert Conroy

11. A list that identifies scheduled outages or retirements of generating capacity during the current year and the following four years.

Response:

The expected maintenance outage schedule for the years 2004 through 2008 is being provided pursuant to a Petition for Confidential Protection. The schedule is regularly modified based on actual operating conditions, forced outages, changes in the schedule in meeting environmental compliance regulations, fluctuations in wholesale prices, and other unforeseen events.

The Companies have retired Green River Units 1 and 2, effective 12/31/2003. Also, KU is presently working with the U.S. Army Corps of Engineers, FERC, and the Kentucky River Authority on the detailed requirements for retirement and license surrender of Lock 7. Lock 7 is expected to be retired in 2005. Additionally, the Companies are reviewing the economic operability of the units contained in the table below. Further discussions on the economic review are contained on page 5-44 of Volume I of the IRP.

Type of Unit	Plant Name	Unit	Summer Capacity	In Service Year	Age (2003)
Steam	Tyrone	1	27	1947	56
Steam	Tyrone	2	31	1948	55
CT	Waterside	7	11	1964	39
CT	Waterside	8	11	1964	39
CT	Cane Run	11	14	1968	35
CT	Paddy's Run	11	12	1968	35
CT	Paddy's Run	12	23	1968	35
CT	Zorn	1	14	1969	34
CT	Haefling	1,2,3	36	1970	33

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION CAPACITY AND TRANSMISSION SYSTEM	)))	ADMINISTRATIVE CASE NO. 387

2003 ANNUAL RESOURCE ASSESSMENT FILING
OF
KENTUCKY UTILITIES COMPANY
PURSUANT TO APPENDIX G
OF THE COMMISSION'S ORDER
DATED DECEMBER 20, 2001

FILED: MARCH 1, 2004

KENTUCKY UTILITIES COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387 FILED MARCH 1, 2004

ITEM NO. 1

RESPONDENT: Robert Thomson

1. Actual and weather-normalized energy sales for the just completed calendar year. Sales should be disaggregated into native load sales and off-system sales. Off-system sales should be further disaggregated into full requirements sales, firm capacity sales, and non-firm or economy energy sales. Off-system sales should be further disaggregated to identify separately all sales where the utility acts as a reseller, or transporter, in a power transaction between two or more other parties.

Response:

Please refer to attached Table KU-1 for actual and weather-normalized billed sales and off-system sales in the requested breakdowns.

TABLE KU-1

NATIVE AND OFF-SYSTEM SALES BY MONTH: 2003 (MWh)

KENTUCKY UTILITIES

ACTUAL NATIVE BILLED SALES	2003 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	662,301	676,995	524,379	358,756	335,102	343,784	499,313	498,616	491,613	332,601	339,001	528,612	5,591,072
Commercial (Includes Lighting)	484,756	474,871	433,009	400,614	429,591	431,739	509,317	503,404	525,365	422,669	395,947	455,803	5,467,086
Industrial	462,007	468,644	458,760	440,243	466,681	458,026	474,098	466,342	484,132	482,986	457,926	484,925	5,604,769
ODP	109,589	111,842	83,746	68,314	61,322	57,986	63,000	63,916	64,950	61,938	66,302	91,750	904,656
Total Internal (Native)	1,718,653	1,732,352	1,499,893	1,267,928	1,292,696	1,291,535	1,545,727	1,532,278	1,566,060	1,300,194	1,259,175	1,561,092	17,567,584

WEATHER NORMALIZED NATIVE BILLED SALES	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	680,134	581,461	501,032	400,038	354,075	392,422	519,874	535,227	490,986	358,563	353,076	530,426	5,697,314
Commercial (Includes Lighting)	488,941	458,325	429,850	407,152	430,422	478,533	525,651	528,716	524,916	448,747	396,967	456,188	5,574,409
Industrial	462,007	468,644	458,760	440,243	466,681	465,760	474,898	469,592	484,018	482,986	457,926	484,925	5,616,438
ODP	110,539	102,895	85,299	71,015	64,128	58,587	63,516	64,254	64,698	62,356	67,990	90,507	905,784
Total Internal (Native)	1,741,621	1,611,325	1,474,941	1,318,448	1,315,306	1,395,302	1,583,939	1,597,788	1,564,619	1,352,652	1,275,959	1,562,047	17,793,946

OFF-SYSTEM SALES From Generation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Firm	64,790	19,374	11,537	37,220	5,552	20,079	30,245	13,970	35,060	20,664	35,469	53,068	347,028
Non-Firm	71,984	30,273	24,518	77,491	16,968	35,783	46,874	23,513	51,439	23,668	51,691	55,543	509,745
Total	136,774	49,647	36,055	114,711	22,520	55,862	77,119	37,483	86,499	44,332	87,160	108,611	856,773
Full Requirements Sales	167,032	151,803	148,110	134,383	143,256	162,962	189,512	184,547	169,052	145,039	125,089	181,767	1,902,552
Brokered Sales	93,544	72,349	60,598	45,624	108,118	54,857	15,580	24,617	54,664	86,785	92,336	85,520	794,592
Total Off-System Sales	397,350	273,799	244,763	294,718	273,894	273,681	282,211	246,647	310,215	276,156	304,585	375,898	3,553,917

KENTUCKY UTILITIES COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING
PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER
DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387
FILED MARCH 1, 2004

ITEM NO. 2

RESPONDENT: Nancy Smith

2. A summary of monthly power purchases for the just completed calendar year. Purchases should be disaggregated into firm capacity purchases required to serve native load, economy energy purchases, and purchases where the utility acts as a reseller, or transporter, in a power transaction between two or more other parties.

Response:

A summary of monthly power purchases for 2002, exclusive of any post-period adjustments and disaggregated, as requested, is provided in the attached table.

Table KU-2
Monthly Power Purchases 2003
Kentucky Utilities

	2003 MWH	Total Cost	$/MWH
JANUARY			
Firm Capacity Purchases Required to Serve Native Load	342,534	$ 7,948,671	$ 23.21
Economy Energy Purchases	389,046	$ 5,784,624	$ 14.87
Company Acts as a Reseller	11,935	$ 585,086	$ 49.02
Brokered Purchases	94,672	$ 3,939,786	$ 41.62
TOTAL	838,187	$ 18,258,166	$ 21.78
FEBRUARY			
Firm Capacity Purchases Required to Serve Native Load	293,022	$ 6,737,331	$ 22.99
Economy Energy Purchases	384,883	$ 6,413,084	$ 16.66
Company Acts as a Reseller	3,466	$ 150,052	$ 43.29
Brokered Purchases	73,005	$ 2,668,051	$ 36.55
TOTAL	754,376	$ 15,968,518	$ 21.17
MARCH			
Firm Capacity Purchases Required to Serve Native Load	326,678	$ 6,991,267	$ 21.40
Economy Energy Purchases	537,589	$ 7,966,990	$ 14.82
Company Acts as a Reseller	1,467	$ 93,547	$ 63.77
Brokered Purchases	61,247	$ 2,546,453	$ 41.58
TOTAL	926,981	$ 17,598,257	$ 18.98
APRIL			
Firm Capacity Purchases Required to Serve Native Load	227,335	$ 6,757,264	$ 29.72
Economy Energy Purchases	351,485	$ 4,586,187	$ 13.05
Company Acts as a Reseller	3,778	$ 140,714	$ 37.25
Brokered Purchases	45,997	$ 1,762,228	$ 38.31
TOTAL	628,595	$ 13,246,393	$ 21.07
MAY			
Firm Capacity Purchases Required to Serve Native Load	242,601	$ 6,959,721	$ 28.69
Economy Energy Purchases	197,260	$ 2,991,486	$ 15.17
Company Acts as a Reseller	1,867	$ 72,116	$ 38.63
Brokered Purchases	109,026	$ 3,761,220	$ 34.50
TOTAL	550,754	$ 13,784,543	$ 25.03
JUNE			
Firm Capacity Purchases Required to Serve Native Load	264,344	$ 6,924,245	$ 26.19
Economy Energy Purchases	342,805	$ 4,216,980	$ 12.30
Company Acts as a Reseller	2,796	$ 93,176	$ 33.32
Brokered Purchases	55,282	$ 1,978,775	$ 35.79
TOTAL	665,227	$ 13,213,176	$ 19.86
JULY			
Firm Capacity Purchases Required to Serve Native Load	299,671	$ 6,975,419	$ 23.28
Economy Energy Purchases	237,400	$ 3,205,337	$ 13.50
Company Acts as a Reseller	3,966	$ 191,861	$ 48.38
Brokered Purchases	15,771	$ 548,855	$ 34.80
TOTAL	556,808	$ 10,921,472	$ 19.61
AUGUST			
Firm Capacity Purchases Required to Serve Native Load	275,405	$ 6,878,440	$ 24.98
Economy Energy Purchases	312,051	$ 4,475,531	$ 14.34
Company Acts as a Reseller	1,955	$ 97,065	$ 49.65
Brokered Purchases	24,753	$ 1,012,685	$ 40.91
TOTAL	614,164	$ 12,463,722	$ 20.29
SEPTEMBER			
Firm Capacity Purchases Required to Serve Native Load	290,802	$ 6,623,176	$ 22.78
Economy Energy Purchases	351,283	$ 4,373,892	$ 12.45
Company Acts as a Reseller	2,457	$ 76,124	$ 30.98
Brokered Purchases	54,783	$ 1,524,151	$ 27.82
TOTAL	699,325	$ 12,597,343	$ 18.01
OCTOBER			
Firm Capacity Purchases Required to Serve Native Load	251,619	$ 6,146,167	$ 24.43
Economy Energy Purchases	466,016	$ 5,773,732	$ 12.39
Company Acts as a Reseller	2,406	$ 53,865	$ 22.39
Brokered Purchases	86,921	$ 2,213,243	$ 25.46
TOTAL	806,962	$ 14,187,007	$ 17.58
NOVEMBER			
Firm Capacity Purchases Required to Serve Native Load	291,919	$ 6,355,935	$ 21.77
Economy Energy Purchases	222,399	$ 2,888,391	$ 12.99
Company Acts as a Reseller	3,990	$ 136,914	$ 34.31
Brokered Purchases	92,488	$ 2,349,495	$ 25.40
TOTAL	610,796	$ 11,730,735	$ 19.21
DECEMBER			
Firm Capacity Purchases Required to Serve Native Load	323,535	$ 6,955,528	$ 21.50
Economy Energy Purchases	418,792	$ 5,260,220	$ 12.56
Company Acts as a Reseller	7,713	$ 331,197	$ 42.94
Brokered Purchases	85,872	$ 2,521,500	$ 29.36
TOTAL	835,912	$ 15,068,445	$ 18.03
TOTAL			
Firm Capacity Purchases Required to Serve Native Load	3,429,465	$ 82,253,163	$ 23.98
Economy Energy Purchases	4,211,009	$ 57,936,455	$ 13.76
Company Acts as a Reseller	47,796	$ 2,021,718	$ 42.30
Brokered Purchases	799,817	$ 26,826,442	$ 33.54
TOTAL	8,488,087	$ 169,037,777	$ 19.91

KENTUCKY UTILITIES COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387 FILED MARCH 1, 2004

ITEM NO. 3

RESPONDENT: Robert Thomson/Robert Conroy

3. Actual and weather-normalized monthly coincident peak demands for the just completed calendar year. Demands should be disaggregated into (a) native load demand (firm and non-firm) and (b) off-system demand (firm and non-firm).

Response:

Please refer to attached Table KU-3 which shows the actual and weather-normalized coincident peak native demands. The normalized native peak demands are available only on a seasonal (summer/winter) basis.

TABLE KU-3
NATIVE AND OFF-SYSTEM DEMANDS BY MONTH FOR 2003

Kentucky Utilities

	Actual			Normal Weather (Seasonal)	Off-System (2)		
Time of Monthly Native Peak	Native Peak	Non-Firm (1)	Firm	Native Peak	Firm (3)	Non-Firm (3)	Total
2003-01-27-09:00	3,944	19	3,925	3,925	0	0	0
2003-02-05-08:00	3,413	70	3,343		0	0	0
2003-03-03-08:00	3,204	65	3,139		0	0	0
2003-04-09-11:00	2,746	74	2,672		0	0	0
2003-05-09-14:00	2,824	72	2,752		41	124	165
2003-06-25-16:00	3,380	19	3,361		0	0	0
2003-07-08-16:00	3,649	0	3,649		0	0	0
2003-08-27-15:00	3,810	0	3,810	3,836	0	0	0
2003-09-10-16:00	3,173	38	3,135		62	91	153
2003-10-03-08:00	2,622	63	2,559		0	0	0
2003-11-25-09:00	3,126	72	3,054		13	19	32
2003-12-17-19:00	3,306	78	3,228		0	0	0

Notes

(1) Non-firm native load is the amount expected from customers served under the KU Curtailable Service Rider.

(2) The allocation of off-system sales split between LG&E and KU is handled in the After-the-Fact Billing process in accordance with the Power Supply System Agreement between LG&E and KU. The individual company sales will include an allocation of the sales sourced with purchased power and allocated to the individual company based on each company's constribution to off-system sales.

(3) The allocation of off-system sales between firm and non-firm is not available from the hourly data in AFB. The breakout is based on the monthly totals for LG&E and KU sales for firm and non-firm sales.

KENTUCKY UTILITIES COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387 FILED MARCH 1, 2004

ITEM NO. 4

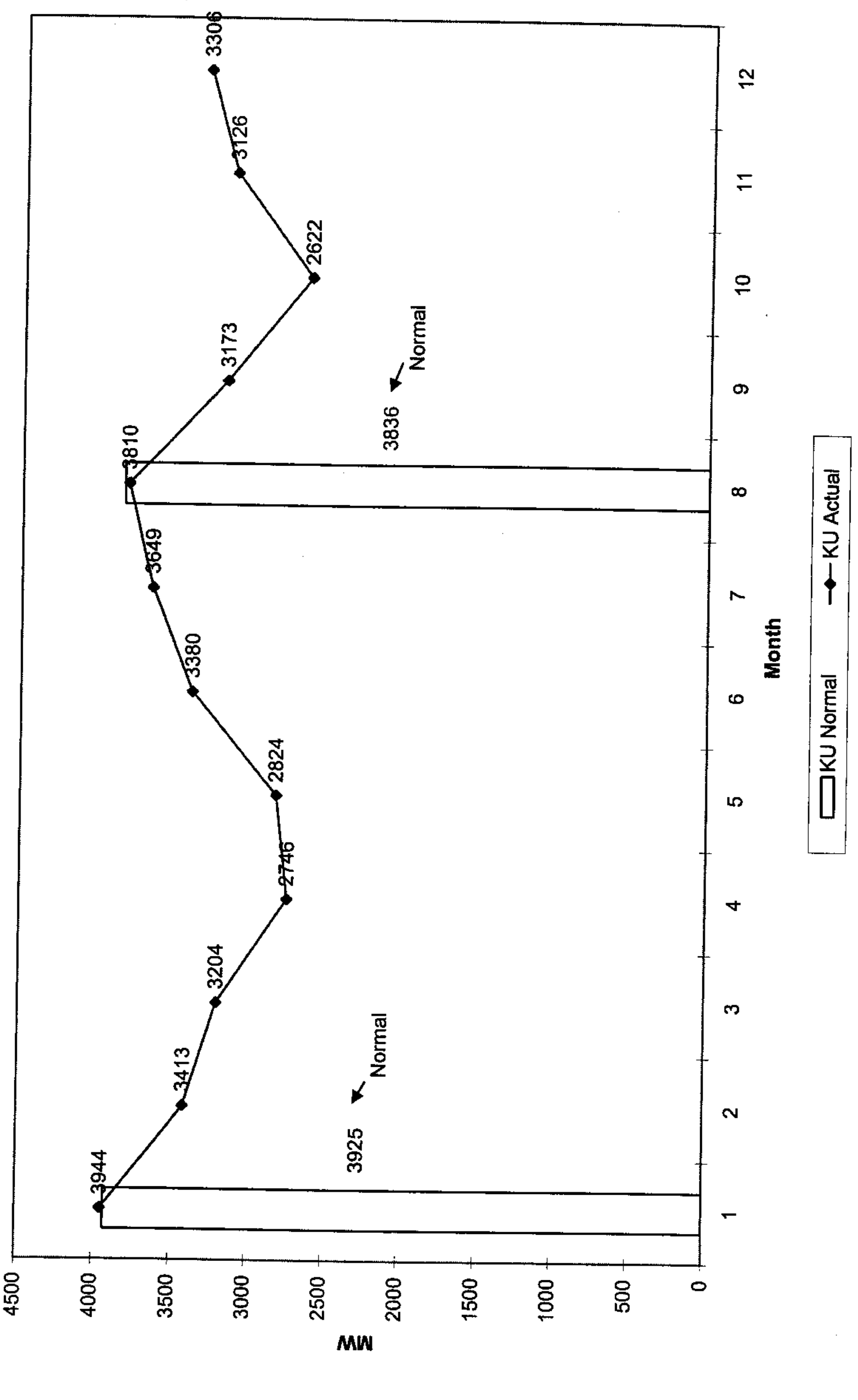
RESPONDENT: Robert Thomson

4. Load shape curves that show actual peak demands and weather-normalized peak demands (native load demand and total demand) on a monthly basis for the just completed calendar year.

Response:

Please refer to attached Figure KU-4.

Figure KU-4
Actual and Weather Normalized KU Peak Demand for 2003



KENTUCKY UTILITIES COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387 FILED MARCH 1, 2004

ITEM NO. 5

RESPONDENT: Robert Conroy

5. Load shape curves showing the number of hours that native load demand exceeded these levels during the just completed calendar year: (1) 70% of the sum of installed generating capacity plus firm capacity purchases; (2) 80% of the sum of installed generating capacity plus firm capacity purchases; (3) 90% of the sum of installed generating capacity plus firm capacity purchases.

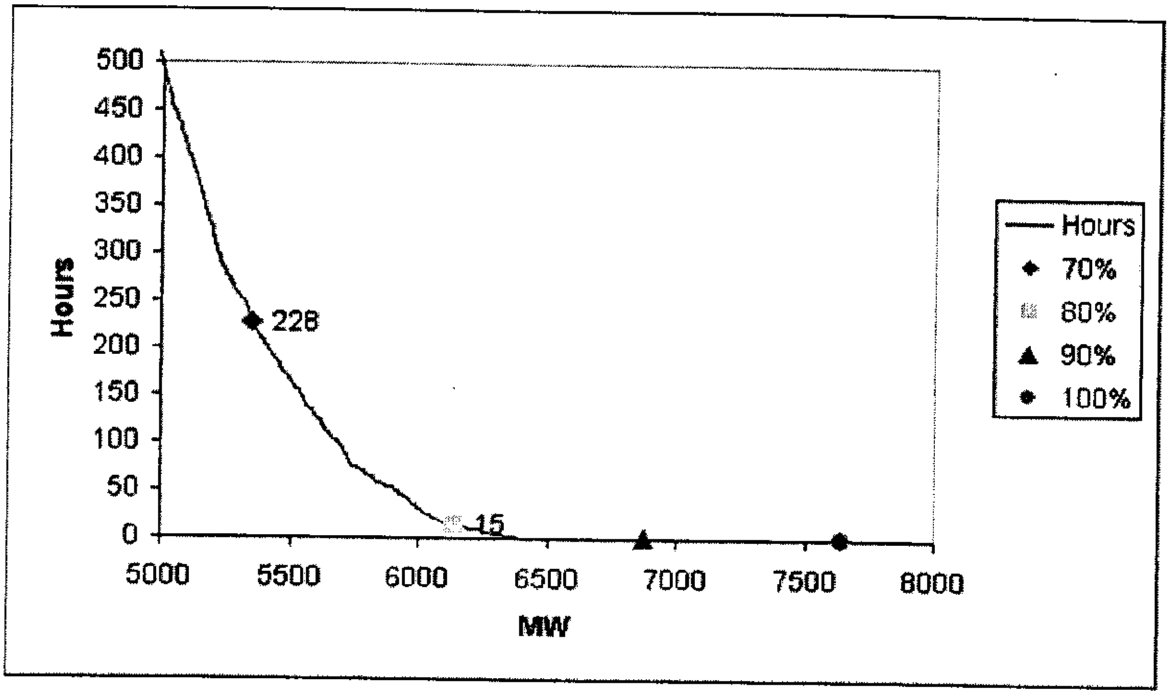
Response:

From a planning perspective KU and LG&E had installed generating capacity of 7,043 MW and firm capacity purchases of 600 MW (total of 7,643 MW) for the summer 2003. The attached graph indicates the number of hours in which actual load was greater than the levels indicated. The table below summarizes this information.

Capacity Level	Number of Hours Load Exceeded
100% - 7,643 MW	0
90% - 6,879 MW	0
80% - 6,114 MW	15
70% - 5,350 MW	228

Figure KU-5

LG&E/KU Combined Load
Number of Hours Load Exceeded 70%, 80%, and 90% of Installed Generating Capacity Plus Firm Capacity Purchases



KENTUCKY UTILITIES COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING
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ITEM NO. 6

RESPONDENT: Robert Thomson/Robert Conroy

6. Based on the most recent demand forecast, the base case demand and energy forecasts and high case demand and energy forecasts for the current year and the following four years. The information should be disaggregated into (a) native load (firm and non-firm demand) and (b) off-system load (both firm and non-firm demand).

Response:

a) Please see the attached Table KU-6a.

b) Off-system sales projections for 2004-2008 are contained in Table KU-6b. For Off-System Sales, only base case total sales energy projections exist for 2004-2008. The projections consist of "Existing OSS", which includes an existing long-term sales agreement with EKPC, and the expected "Wholesale" market sales. In the long-range model, wholesale financially Firm and Non-firm sales are not distinguished but are combined into an overall expected sales energy. However, based on the breakout of firm and non-firm sales identified in response to Item No. 1 for both LG&E and KU, approximately 40% of the total sales energy would be financially Firm, and 60% would be Non-firm.

The projection is developed in-house using the Henwood Energy Services Inc. PROSYM hourly production cost model, with market prices based on data provided to the LG&E Energy Marketing group from several external parties including utilities, energy marketing entities, and/or brokers.

TABLE KU-6a

KENTUCKY UTILITIES

BASE CASE

	2004	2005	2006	2007	2008
Energy Sales (MWh)	21,272,697	21,811,564	22,273,178	22,929,758	23,530,222
Native Peak Demand (MW)					
Firm	3,967	4,067	4,153	4,275	4,387
Non-Firm	-	-	-	-	-

Table KU-6b
Total Base Case Off-System Sales Energy Projection

	2004	2005	2006	2007	2008
Existing OSS (GWH)	312	139	0	0	0
Wholesale OSS (GWH)	3,064	3,003	2,850	2,546	2,557
Total OSS (GWH)	3,377	3,142	2,850	2,546	2,557

KENTUCKY UTILITIES COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387 FILED MARCH 1, 2004

ITEM NO. 7

RESPONDENT: Robert Conroy

7. The target reserve margin currently used for planning purposes, stated as a percentage of demand. If changed from what was in use in 2001, include a detailed explanation for the change.

Response:

The Companies established a reserve margin target for 2004 and beyond in the range of 13% to 15%, which provides an optimum level of reliability through various system operating conditions. The reserve margin analysis was performed as part of the 2002 Integrated Resource Plan, filed with the Commission in October 2002 (Case No. 2002-00367). The Companies' expansion plan is based on maintaining a 14% target reserve margin.

The Companies utilized a target reserve margin of 12% in 2001 and 14% in 2002 based on a reserve margin range of 11%-14% established in the Companies' 1999 IRP. A detailed explanation of the change to the current target reserve margin is documented in the report titled "2002 Analysis of Reserve Margin Planning Criterion" contained in Volume III of the Companies' 2002 IRP.

KENTUCKY UTILITIES COMPANY

**2003 ANNUAL RESOURCE ASSESSMENT FILING
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ITEM NO. 8

RESPONDENT: Robert Conroy

8. Projected reserve margins stated in megawatts and as a percentage of demand for the current year and the following 4 years. Identify projected deficits and current plans for addressing these. For each year identify the level of firm capacity purchases projected to meet native load demand.

Response:

The requested reserve margin data is specified in the attached table LGE-8. The capacity in MW required to meet the reserve margin targets of 13% and 15% are also specified in the table. These values represent reserve margins prior to any future resource acquisition. Based on the current load forecast, no deficits are projected over the five-year period.

Table KU-8
Combined Company
Reserve Margin Needs (MW)

Current Values	2004	2005	2006	2007	2008
Peak Load	6,632	6,796	6,911	7,051	7,225
CSR/Interrupt	-100	-100	-100	-100	-100
New DSM	-44	-67	-89	-108	-116
Net Load	6,488	6,629	6,722	6,843	7,009
Existing Capability	6,975	6,977	6,968	6,970	6,971
EEI	200	200	200	200	200
OMU	193	191	189	186	184
OVEC	209	209	209	209	209
Total Supply	7,577	7,577	7,566	7,565	7,564
MW Margin	1,089	948	844	722	555
Reserve Margin %	16.8%	14.3%	12.6%	10.6%	7.9%
Capacity Need for 13%	(245)	(86)	30	168	356
Capacity Need for 15%	(116)	47	165	304	496
New Capacity	608	0	0	0	0
Total Supply	8,185	8,185	8,174	8,173	8,172
Reserve Margin, MW	1,697	1,556	1,452	1,330	1,163
Reserve Margin %	26.2%	23.5%	21.6%	19.4%	16.6%

Based on 2004 Load forecast.

KENTUCKY UTILITIES COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387 FILED MARCH 1, 2004

ITEM NO. 9

RESPONDENT: Robert Conroy

9. By date and hour, identify all incidents during the just completed calendar year when reserve margin was less than the East Central Area Reliability Council's ("ECAR") 1.5% spinning reserve requirement. Include the amount of capacity resources that were available, the actual demand on the system, and the reserve margin, stated in megawatts and as a percentage of demand. Also identify system conditions at the time.

Response:

From a planning perspective, the Companies have secured reserve to maintain a reserve margin above the minimum value of the target reserve margin range in all peak months from January 2003 to the present.

The reserve margin target is a planning criterion, not an operating criterion. The purpose of the reserve margin is to maintain a level of capacity in reserve - capacity that is available should there be an unexpected loss of generation, reduced generation capacity due to equipment problems, unanticipated load growth, variances in load due to extreme weather conditions, and/or disruptions in contracted purchased power. These events are operating events; the reserve margin criterion is a method used to plan for such events, not a standard against which operating conditions are to be measured. In other words, securing a 14% planning reserve margin for the summer peak period does not mean that the Companies will maintain 14% reserve capacity in every hour of actual operation.

In the operating arena, reserve criteria exist that are analogous to the reserve margin target criteria of the planning arena. Operating Reserve is maintained on a real-time basis, to maintain system reliability should any of the operating events listed above occur. The June through December 2003 data is not available from ECAR at this time. Note that the attachments reflect Spinning Reserve only; the Companies maintain other reserves that are not included in the ECAR data. Table KU-9 highlights those hours during 2003 for which the ECAR report indicates the Companies had insufficient spinning reserve.

FAX

PLEASE DELIVER IMMEDIATELY TO THE PERSON LISTED FOR YOUR COMPANY

TO: **Jason Knoy** **Business Fax: (502) 217-2360**

LGEE

FROM: Sandy Ross - ECAR

DATE: February 25, 2004

6 pages including cover sheet.

Hi Jason,

Please find the Spinning Reserve Reports for January 2003 thru May 2003 attached.
Please contact me if you have any questions.

Thanks,

Sandy Ross
ECAR

PHONE: 330/580-8011
FAX: 330/456-5408

LGEE SPINNING RESERVE REPORT FOR THE MONTH OF JANUARY 2003

DATE	AFTER THE FACT					
	COMMON HOUR SPINNING			PEAK HOUR SPINNING		
	REQUIRED	ACTUAL		REQUIRED	ACTUAL	
	MW	MW	% RESV	MW	MW	% RESV
Wed 1	0	0	0.0	0	0	0.0
Thu 2	66	595	13.5	66	595	13.5
Fri 3	71	313	6.6	71	313	6.6
Sat 4						
Sun 5						
Mon 6	73	327	6.8	73	327	6.8
Tue 7	71	300	6.3	74	515	10.4
Wed 8	64	315	7.4	69	354	7.7
Thu 9	62	538	13.1	64	656	15.3
Fri 10	70	496	10.7	70	379	8.1
Sat 11						
Sun 12						
Mon 13	70	292	6.3	75	1051	20.9
Tue 14	75	380	7.6	75	256	5.1
Wed 15	74	333	6.7	80	618	11.6
Thu 16	76	-361	-7.1*	76	-361	-7.1*
Fri 17	75	700	14.0	78	105	2.0
Sat 18						
Sun 19						
Mon 20	68	735	16.2	69	692	15.1
Tue 21	73	493	10.1	74	243	4.9
Wed 22	79	338	6.4	80	276	5.2
Thu 23	88	293	5.0	88	333	5.7
Fri 24	79	335	6.3	88	1043	17.8
Sat 25						
Sun 26						
Mon 27	81	588	10.9	88	425	7.2
Tue 28	70	392	8.3	75	357	7.1
Wed 29	71	297	6.3	71	297	6.3
Thu 30	71	278	5.9	72	281	5.8
Fri 31	67	318	7.1	73	283	5.8

NOTE: The After-the-Fact spinning reserve has been adjusted to reflect zero net inadvertent.

* DENOTES LESS THAN 1.5% SPINNING RESERVE

LGEE SPINNING RESERVE REPORT FOR THE MONTH OF FEBRUARY 2003

DATE		AFTER THE FACT					
		COMMON HOUR SPINNING			PEAK HOUR SPINNING		
		REQUIRED	ACTUAL		REQUIRED	ACTUAL	
		MW	MW	% RESV	MW	MW	% RESV
Sat	1						
Sun	2						
Mon	3	61	244	6.0	62	247	6.0
Tue	4	70	344	7.4	72	315	6.6
Wed	5	70	331	7.1	77	337	6.5
Thu	6	72	334	6.9	72	345	7.1
Fri	7	75	325	6.5	76	545	10.8
Sat	8						
Sun	9						
Mon	10	72	495	10.3	73	398	8.2
Tue	11	68	588	13.1	73	178	3.6
Wed	12	69	581	12.6	73	590	12.1
Thu	13	65	285	6.6	77	281	5.5
Fri	14	66	312	7.0	70	348	7.4
Sat	15						
Sun	16						
Mon	17	68	450	9.9	69	400	8.7
Tue	18	70	315	6.7	72	333	6.9
Wed	19	67	618	13.9	70	278	6.0
Thu	20	65	356	8.3	68	308	6.7
Fri	21	62	800	19.5	66	329	7.5
Sat	22						
Sun	23						
Mon	24	71	359	7.6	73	360	7.4
Tue	25	72	251	5.2	78	324	6.3
Wed	26	72	369	7.7	75	306	6.1
Thu	27	68	263	5.8	73	290	6.0
Fri	28	64	775	18.2	70	324	7.0

NOTE: The After-the-Fact spinning reserve has been adjusted to reflect zero net inadvertent.

* DENOTES LESS THAN 1.5% SPINNING RESERVE

LGEE SPINNING RESERVE REPORT FOR THE MONTH OF MARCH 2003

DATE	AFTER THE FACT: COMMON HOUR SPINNING REQUIRED MW	COMMON HOUR SPINNING ACTUAL MW	COMMON HOUR SPINNING ACTUAL % RESV	PEAK HOUR SPINNING REQUIRED MW	PEAK HOUR SPINNING ACTUAL MW	PEAK HOUR SPINNING ACTUAL % RESV
Sat 1						
Sun 2						
Mon 3	61	277	6.8	73	341	7.0
Tue 4	58	351	9.0	70	272	5.9
Wed 5	62	296	7.2	63	182	4.3
Thu 6	68	303	6.7	70	259	5.6
Fri 7	55	860	23.4	70	420	8.9
Sat 8						
Sun 9						
Mon 10	64	268	6.3	73	322	6.6
Tue 11	58	485	12.5	68	352	7.7
Wed 12	56	545	14.5	64	200	4.7
Thu 13	59	256	6.5	61	220	5.4
Fri 14	55	228	6.2	65	245	5.6
Sat 15						
Sun 16						
Mon 17	56	341	9.2	59	267	6.8
Tue 18	56	203	5.4	58	214	5.5
Wed 19	55	384	10.5	57	220	5.8
Thu 20	55	246	6.8	57	217	5.7
Fri 21	53	496	13.9	57	268	7.1
Sat 22						
Sun 23						
Mon 24	54	491	13.7	57	55	1.4*
Tue 25	55	274	7.5	58	214	5.6
Wed 26	54	597	16.5	57	338	8.8
Thu 27	53	431	12.1	58	479	12.5
Fri 28	52	415	11.9	56	244	6.5
Sat 29						
Sun 30						
Mon 31	56	491	13.0	64	303	7.1

NOTE: The After-the-Fact spinning reserve has been adjusted to reflect zero net inadvertent.

* DENOTES LESS THAN 1.5% SPINNING RESERVE

LGEE SPINNING RESERVE REPORT FOR THE MONTH OF APRIL 2003

DATE		AFTER THE FACT					
		COMMON HOUR SPINNING			PEAK HOUR SPINNING		
		REQUIRED	ACTUAL		REQUIRED	ACTUAL	
		MW	MW	% RESV	MW	MW	% RESV
Tue	1	58	362	9.4	63	495	11.8
Wed	2	55	603	16.3	59	151	3.9
Thu	3	0	423	0.0	0	143	0.0
Fri	4	54	765	21.1	59	304	7.8
Sat	5						
Sun	6						
Mon	7	57	591	15.6	59	695	17.6
Tue	8	57	600	15.9	58	330	8.5
Wed	9	65	2069	48.1	65	623	14.5
Thu	10	60	437	10.9	64	367	8.6
Fri	11	56	213	5.7	60	483	12.0
Sat	12						
Sun	13						
Mon	14	58	362	9.4	59	285	7.3
Tue	15	62	258	6.2	62	258	6.2
Wed	16	62	467	11.2	62	405	9.7
Thu	17	58	218	5.6	59	218	5.5
Fri	18	51	325	9.5	54	129	3.6
Sat	19						
Sun	20						
Mon	21	57	235	6.2	57	227	6.0
Tue	22	56	295	7.9	57	229	6.0
Wed	23	55	252	6.8	59	488	12.3
Thu	24	56	285	7.7	57	436	11.4
Fri	25	55	407	11.1	57	278	7.4
Sat	26						
Sun	27						
Mon	28	60	140	3.5	60	339	8.4
Tue	29	64	363	8.5	65	238	5.5
Wed	30	65	115	2.6	68	168	3.7

NOTE: The After-the-Fact spinning reserve has been adjusted to reflect zero net inadvertent.

* DENOTES LESS THAN 1.5% SPINNING RESERVE

LGEE SPINNING RESERVE REPORT FOR THE MONTH OF MAY 2003

DATE	AFTER THE FACT: COMMON HOUR SPINNING REQUIRED MW	COMMON HOUR SPINNING ACTUAL MW	COMMON HOUR SPINNING ACTUAL % RESV	PEAK HOUR SPINNING REQUIRED MW	PEAK HOUR SPINNING ACTUAL MW	PEAK HOUR SPINNING ACTUAL % RESV
Thu 1	70	-239	-5.1*	70	-128	-2.7*
Fri 2	59	396	10.0	60	215	5.4
Sat 3						
Sun 4						
Mon 5	0	561	0.0	0	562	0.0
Tue 6	64	386	9.1	65	490	11.2
Wed 7	61	629	15.5	61	559	13.7
Thu 8	68	427	9.4	68	394	8.7
Fri 9	72	172	3.6	72	172	3.6
Sat 10						
Sun 11						
Mon 12	58	223	5.7	59	266	6.8
Tue 13	60	253	6.3	61	140	3.5
Wed 14	63	249	6.0	63	239	5.7
Thu 15	61	378	9.3	61	310	7.6
Fri 16	64	260	6.1	64	305	7.1
Sat 17						
Sun 18						
Mon 19	70	473	10.1	71	316	6.6
Tue 20	64	670	15.6	65	633	14.6
Wed 21	57	1788	47.4	57	1728	45.3
Thu 22	59	643	16.3	59	643	16.3
Fri 23	59	220	5.6	59	220	5.6
Sat 24						
Sun 25						
Mon 26	0	0	0.0	0	0	0.0
Tue 27	61	302	7.5	61	302	7.5
Wed 28	64	255	6.0	64	255	6.0
Thu 29	58	384	9.9	58	234	6.0
Fri 30	61	238	5.9	61	298	7.3
Sat 31						

NOTE: The After-the-Fact spinning reserve has been adjusted to reflect zero net inadvertent.

* DENOTES LESS THAN 1.5% SPINNING RESERVE

Table KU-9
Summary of ECAR Spinning Reserve Events <1.5% for LG&E/KU

Date	ECAR Reported Spinning Reserve				Gross Generation (MW)	Purchases (MW)	Gross Native Load (MW)	LG&E/KU System Conditions					
								Units On Forced Outage		Units On Maintenance		Available Generation not Synchronized	
	Required MW	Actual MW	Required %	Actual %				Units	MW	Units	MW	Units	MW
1/16/2003	76	-361	1.5%	-7.1%	5200	516	4553	Green River 3	75	Mill Creek 1	330	Brown 5-8, Brown 10-11, Cane Run 11, Haefling 1-3, Paddys Run 11-13, Trimble County 5-6, Tyrone 1-2, Waterside 7-8, Zorn 1	1646
3/24/2003	57	55	1.5%	1.4%	4391	554	3412	Brown 3[1], Ohio Falls	64	Ghent 3, Green River 3, Green River 1-2, Green River 4, Tyrone 3, Cane Run 5, Mill Creek 2	1347	Brown 5-11, Cane Run 11, Green River 1-2, Haefling 1-3, Paddys Run 11-13, Trimble County 5-6, Tyrone 1-2, Waterside 7-8, Zorn 1	1787
5/1/2003	70	-128	1.5%	-2.7%	4247	728	4200	Ghent 3, Mill Creek 3[2], Mill Creek 4[3], Brown 5	731	Ghent 1, Green River 4, Tyrone 3, Mill Creek 2, Trimble County 1	1437	Brown 5, Brown 8-11, Cane Run 11, Green River 1-2, Haefling 1-3, Paddys 11-12, Tyrone 1-2, Waterside 7-8, Zorn 1	777

1 - Brown 3 derated 32 MW, not entirely forced out
2 - Mill Creek 3 derated 18 MW, not entirely forced out
3 - Mill Creek 4 derated 68 MW, not entirely forced out

KENTUCKY UTILITIES COMPANY

**2003 ANNUAL RESOURCE ASSESSMENT FILING
PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER
DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387
FILED MARCH 1, 2004**

ITEM NO. 10

RESPONDENT: Robert Conroy

10. A list identifying and describing all forced outages in excess of 2 hours in duration during the just completed calendar year.

Response:

A list of all requested outages is included in the attached Table KU-10.

KU jointly owned units on LG&E sites are referenced in LG&E's Response to Item No. 10.

TABLE KU-10
KENTUCKY UTILITIES COMPANY
POWER GENERATION
FORCED OUTAGES GREATER THAN TWO HOURS
2003

Unit	Outage Start/End Dates	Outage Event Description	Duration Hours	Duration Minutes
Brown 1	03/12 - 03/13	CIRCUIT BREAKERS	11	0
Brown 2	03/12 - 03/15	FIRST REHEATER LAGGING/FOULING	75	59
	03/30 - 04/03	ECONOMIZER LEAK	86	54
	04/06 - 04/10	FIRST SUPERHEATER LEAK	79	13
	04/11 - 04/11	UNIT AUXILIARIES TRANSFORMER	6	22
Brown 3	03/17 - 03/20	AIR HEATER	64	46
	03/29 - 03/31	BOILER RECIRCULATION PUMPS	36	23
	04/02 - 04/02	INDUCED DRAFT FAN CONTROLS	6	6
	07/30 - 08/02	FIRST SUPERHEATER SLAGGING/FOULING	61	5
	08/21 - 08/22	EXCITER PROBLEMS	4	7
	10/21 - 10/22	BOTTOM ASH CLINKER GRINDERS	24	21
	10/27 - 10/31	FIRST SUPERHEATER SLAGGING/FOULING	91	16
Brown 5	05/01 - 05/02	INLET AIR VANES	19	26
	08/21 - 08/22	INLET AIR VANES	20	18
Brown 6	02/25 - 03/05	FUEL SYSTEM PROBLEMS	188	30
Brown 7	12/19 - 12/20	FUEL SYSTEM PROBLEMS	16	8
Brown 8	02/03 - 02/04	TURNING GEAR AND MOTOR	28	30
	02/05 - 02/05	MISC GENERATOR PROBLEMS	6	19
	04/03 - 04/04	LUBE OIL PUMPS	32	0
Brown 11	03/07 - 03/07	FUEL SYSTEM PROBLEMS	3	35
Ghent 1	02/07 - 02/08	TURBINE GOVERNING SYSTEM	4	6
	04/07 - 04/09	FURNACE WALL LEAK	40	50
	04/16 - 04/18	FURNACE WALL LEAK	42	6
	05/21 - 05/21	PULVERIZER CONTROL SYSTEM	2	2
	05/21 - 05/22	PULVERIZER CONTROL SYSTEM	22	26
	08/22 - 08/23	FURNACE WALL LEAK	19	29
	08/24 - 08/25	FIRST SUPERHEATER LEAK	39	12
	12/22 - 12/24	FIRST SUPERHEATER LEAK	62	59
Ghent 3	04/19 - 04/19	FIRST REHEATER LEAK	14	22
	05/01 - 05/04	FIRST SUPERHEATER LEAK	73	58
	07/25 - 07/27	FIRST SUPERHEATER LEAK	42	59
	08/06 - 08/07	FIRST SUPERHEATER LEAK	24	22
	10/19 - 10/20	CONDENSER TUBE LEAK	22	54

TABLE KU-10
KENTUCKY UTILITIES COMPANY
POWER GENERATION
FORCED OUTAGES GREATER THAN TWO HOURS
2003

Unit	Outage Start/End Dates	Outage Event Description	Duration Hours	Duration Minutes
Ghent 4	03/05 - 03/07	FIRST SUPERHEATER LEAK	36	8
	03/27 - 03/27	OPACITY	7	38
	12/13 - 12/13	INDUCED DRAFT FAN MOTOR	2	7
Green River 1	02/24 - 02/25	BOILER TUBE LEAK	9	24
	06/30 - 08/11	SCRUBBER PROBLEMS	1011	0
Green River 2	02/24 - 02/25	BOILER TUBE LEAK	9	24
	06/30 - 08/11	SCRUBBER PROBLEMS	1011	0
Green River 3	02/02 - 02/02	BOILER TUBE LEAK	4	35
	02/28 - 03/01	BOILER TUBE LEAK	21	11
	04/07 - 04/07	EXCITER PROBLEM	13	38
	04/11 - 04/14	GENERATOR BRUSHRIGGING	76	52
	05/10 - 05/12	CONDENSER TUBE CASING AND INTERNAL PROBLEMS	31	11
	05/12 - 05/12	DESUPERHEATER/ATTEMPERATOR VALVES	2	30
	05/12 - 07/12	MAJOR TURBINE OVERHAUL	1475	1
	07/16 - 07/16	EXCITER PROBLEM	5	1
	08/04 - 08/06	BOILER TUBE LEAK	47	21
	08/20 - 08/22	BOILER WATER CONDITION	53	15
	10/23 - 10/23	GENERATOR VOLTAGE CONTROL	11	6
	12/19 - 12/19	GENERATOR BEARINGS AND LUBE OIL SYSTEM	9	33
Green River 4	05/19 - 05/22	GENERATOR CASING	73	28
	05/27 - 05/31	GENERATOR PROBLEMS	84	1
	08/26 - 10/13	LP TURBINE BUCKETS OR BLADES	1162	34
	10/13 - 10/17	LP TURBINE BUCKETS OR BLADES	94	31
	10/18 - 10/23	IP TURBINE BUCKETS OR BLADES	123	32
	11/28 - 11/28	HP HEATER PROBLEM	10	25
	12/09 - 12/10	FURNACE WALL LEAK	31	51
Tyrone 3	06/11 - 06/13	BOILER WATER CONDITION	53	31
	08/17 - 08/17	SOLID STATE EXCITER ELEMENT	6	8
	08/17 - 08/18	TURBINE MAIN STOP VALVES	12	20
	11/13 - 11/13	TRAVELING SCREENS CLOGGED	10	59

KENTUCKY UTILITIES COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING
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FILED MARCH 1, 2004

ITEM NO. 11

RESPONDENT: Robert Conroy

11. A list that identifies scheduled outages or retirements of generating capacity during the current year and the following four years.

Response:

The expected maintenance outage schedule for the years 2004 through 2008 is being provided pursuant to a Petition for Confidential Protection. The schedule is regularly modified based on actual operating conditions, forced outages, changes in the schedule in meeting environmental compliance regulations, fluctuations in wholesale prices, and other unforeseen events.

The Companies have retired Green River Units 1 and 2, effective 12/31/2003. Also, KU is presently working with the U.S. Army Corps of Engineers, FERC, and the Kentucky River Authority on the detailed requirements for retirement and license surrender of Lock 7. Lock 7 is expected to be retired in 2005. Additionally, the Companies are reviewing the economic operability of the units contained in the table below. Further discussions on the economic review are contained on page 5-44 of Volume I of the IRP.

Type of Unit	Plant Name	Unit	Summer Capacity	In Service Year	Age (2003)
Steam	Tyrone	1	27	1947	56
Steam	Tyrone	2	31	1948	55
CT	Waterside	7	11	1964	39
CT	Waterside	8	11	1964	39
CT	Cane Run	11	14	1968	35
CT	Paddy's Run	11	12	1968	35
CT	Paddy's Run	12	23	1968	35
CT	Zorn	1	14	1969	34
CT	Haefling	1,2,3	36	1970	33

KENTUCKY UTILITIES COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING
PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER
DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387
FILED MARCH 1, 2004

ITEM NO. 12

RESPONDENT: Robert Conroy

12. Identify all planned base load or peaking capacity additions to meet native load requirements over the next 10 years. Show the expected in-service date, size and site for all planned additions. Include additions planned by the utility, as well as those by affiliates, if constructed in Kentucky or intended to meet load in Kentucky.

Response:

The Companies were granted a Certificate of Public Convenience and Necessity for the Acquisition of the Four Combustion Turbines on March 18, 2003 (Case No. 2002-00381). The combustion turbines will be available for operation by the summer of 2004. The Companies are currently evaluating the baseload need identified in the 2002 IRP. The table below contains MW needs to maintain a 14% reserve margin through 2013 based on the most recent load forecast.

The Companies are not aware of any planned additions by utility affiliates to be constructed in Kentucky to meet load in Kentucky. However, the Companies and the utility affiliates continually review and study possible base load and/or peaking capacity additions.

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MW Need	(789)	(628)	(511)	(372)	(182)	(14)	114	312	430	658

KENTUCKY UTILITIES COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING
PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER
DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387
FILED MARCH 1, 2004

ITEM NO. 13

RESPONDENT: Mark Johnson

13. The following transmission energy data for the just completed calendar year and the forecast for the current year and the following four years:

    a. Total energy received from all interconnections and generation sources connected to the transmission system.

    b. Total energy delivered to all interconnections on the transmission system.

    c. Peak load capacity of the transmission system.

    d. Peak demand for summer and winter seasons on the transmission system.

Response:

Data exists for 2003. No forecasts exist for 2003-2008.

a. LG&E and KU are operated as one NERC Control Area, statistics below are total sources for the single Control Area for 2003:

Tie Lines Received (GWH)	13,467,467
Net Generation LG&E (GWH)	12,172,559
Net Generation KU (GWH)	20,700,072
Total Sources (GWH)	46,340,098

b. LG&E and KU are operated as one NERC Control Area, the amount of energy delivered at the interconnections of the single Control Area for 2003 was 15,086,376 GWH(s).

c. There is no set number for peak load capacity for the transmission system. The system is built to support native load under first contingency conditions. Actual transmission capacity available for native load, import, export or thru-flow will vary depending on which facilities in the Transmission System of the Eastern Interconnect are in service.

d. The maximum summer peak transmission load for the common Control Area was 6573 MW for the peak hour of August 27, 2003, with 3979 MW of load on the KU transmission facilities and 2594 on the LG&E transmission facilities.

   The maximum winter peak transmission load for the common Control Area was 6107 MW for the peak hour of January 23, 2003, with 4273 MW of load on the KU transmission facilities and 1834 on the LG&E transmission facilities.

KENTUCKY UTILITIES COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387 FILED MARCH 1, 2004

ITEM NO. 14

RESPONDENT: Mark Johnson

14. Identify all planned transmission capacity additions for the next 10 years. Include the expected in-service date, size and site for all planned additions and identify the transmission need each addition is intended to address.

Response:

The Midwest ISO's 10 year expansion plan, dated 12/4/03, is attached for the planned and proposed projects on the LG&E and KU Transmission System for facilities greater than 100 KV. In addition the exhibit attached contains an explanation of need for the planned and proposed projects for all voltage levels.

Form 1 of 2 for Reporting Lines and Transformers In the Baseline Reliability Study (MTEP-04)

Note #1: PLANNED projects are the preferred solution to an identified issue. PROPOSED projects are a tentative solution to an identified Issue.

Note #2: The projects in this list are projected for service on the date indicated. They are expected to be needed to meet existing committments including network and native load growth. Becuase there is always the possibility of delay in permitting and construction, or for modification or deferral of projects as system conditions change, Transmission Providers should not assume that these projects are In Service when selling new transmission service. New transmission service should be conditioned on the completion of these projects.

Planned Transmission Lines and Transformers:

Row ID Number	Note # 2 above		From	To				Line Mile Estimates				Need Estimate (SUM of Columns =100 %)				Status (Note #1 above)				Project Number	Group
591	6/17/03	E-IOK	Kenton (to Wedonia 1200A Reactor 5% p.u. Z)			138	[redacted]				287		50		50	In Service	LGEE	?	$ 363,000	LGEE13	
489	5/31/04	E-IOK	Beargrass	Jeffersonville Jct. (CIN)	1	138	[redacted]	0.2		0.2	258	100				Proposed	LGEE	Y	$ 52,000	LGEE2	
490	5/31/04	E-IOK	Middletown		1	345/138	[redacted]	0.0			448	100				Proposed	LGEE	Y	$ 125,000	LGEE1	
491	5/31/04	E-IOK	Middletown		2	345/138	[redacted]	0.0			448	100				Proposed	LGEE	Y	$ 125,000	LGEE1	
492	5/31/04	E-IOK	Middletown		3	345/138	[redacted]	0.0			448	100				Proposed	LGEE	Y	$ 125,000	LGEE1	
493	5/31/04	E-IOK	Middletown	Buckner	1	345	[redacted]	14.3		14.3	1066	100				Proposed	LGEE	Y	$ 5,000	LGEE3	
494	5/31/04	E-IOK	Northside	Beargrass	1	138	[redacted]	0.2		0.2	258	100				Proposed	LGEE	Y	$ 52,000	LGEE2	
495	5/31/04	E-IOK	Northside	Jeffersonville Jct. (CIN)	1	138	[redacted]	0.1		0.1	292	100				Proposed	LGEE	Y	$ 52,000	LGEE2	
161	11/30/04	E-IOK	Lake Reba Tap	JK Smith (EKPC)	1	138	N11	10.3		10.3	251	50	50			Proposed	LGEE	Y	$ 5,000	LGEE4	
156	5/31/05	E-IOK	Hardin County		2	345/138	M11		0.0		450	100				Proposed	LGEE	Y	$ 4,695,000		75
480	5/31/05	E-IOK	Middletown	Bluegrass Parkway	1	138	[redacted]		4.0	4.0	292	100				Proposed	LGEE	Y	$ 3,320,000	LGEE5	
481	5/31/05	E-IOK	Northside	Beargrass	1	138	[redacted]	0.2		0.2	292	100				Proposed	LGEE	Y	$ 53,000	LGEE2	
482	5/31/06	E-IOK	Brown North	Tyrone	1	138	[redacted]	20.1		20.1	179	100				Proposed	LGEE	Y	$ 331,000	LGEE7	
483	5/31/06	E-IOK	Middletown		4	345/138	M11		0.0		450	50		50		Proposed	LGEE	Y	$ 4,695,000	LGEE13	
484	5/31/07	E-IOK	Mill Creek	Manslick	1	138	[redacted]	6.8		6.8	193	100				Proposed	LGEE	Y	$ 85,000	LGEE8	
485	11/30/07	E-IOK	Fawkes	Fawkes EKPC Tap	1	138	[redacted]	0.1		0.1	202	100				Proposed	LGEE	Y	$ 142,000	LGEE8	
486	11/30/07	E-IOK	Pocket North 500/161		2	500/161	M11		0.0		450	100				Proposed	LGEE	Y	$ 3,416,000	LGEE9	
487	12/31/08	E-IOK	Blue Lick	Bullitt County (EKPC)	1	161	[redacted]	8.2		8.2	235	0		100		Proposed	LGEE	Y	$ 1,180,000		14
488	12/31/08	E-IOK	Elizabethtown	Hardin County	1	138	[redacted]		1.3	1.3	224	50		50		Proposed	LGEE	Y	$ 1,106,000		14
139	12/31/08	E-IOK	Ghent	Owen County Tap	1	138	[redacted]	12.5		12.5	245	50		50		Proposed	LGEE	Y	$ 2,390,000		14
157	12/31/08	E-IOK	Mill Creek	Hardin County	1	345	M11		43.0	43.0	1195	50		50		Proposed	LGEE	Y	$ 60,139,000		14
159	12/31/08	E-IOK	Trimble County	Ghent	1	345	M10		2.8	2.8	598	0	100			Proposed	LGEE	Y	$ 4,598,000		14
160	12/31/08	E-IOK	Trimble County	Speed (Cinergy)	1	345	M10		2.8	2.8	1002	0	100			Proposed	LGEE	Y	$ 4,598,000		14
489	12/31/08	E-IOK	West Frankfort	Tyrone	1	138	[redacted]		10.2	10.2	224	50	50			Proposed	LGEE	Y	$ 9,003,000		14
490	12/31/08	E-IOK	West Lexington	Higby Mill	1	138	[redacted]		11.8	11.8	179	50		50		Proposed	LGEE	Y	$ 2,864,000		14
491	5/31/09	E-IOK	Brown CT	Danville North	1	138	[redacted]		19.0	19.0	245	100				Proposed	LGEE	Y	$ 9,793,000	LGEE10	
492	5/31/09	E-IOK	Brown North	Higby Mill	1	138	[redacted]	16.0		16.0	224	100				Proposed	LGEE	Y	$ 20,000	LGEE11	
145	5/31/09	E-IOK	Middletown	Plainview Tap	1	138	[redacted]	2.4		2.4	292	100				Proposed	LGEE	Y	$ 1,806,000	LGEE5	
493	11/30/09	E-IOK	Lake Reba Tap	West Irvine Tap	1	161	N11	13.8		13.8	190	100				Proposed	LGEE	Y	$ 5,000	LGEE12	

Response to Item No. 14
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Johnson

_04/03

Form 2 of 2 for Reporting Substation Devices in the Baseline Reliability Study (MTEP-04)

Devices (capacitors, reactors, FACTS, etc):

Note #1: PLANNED projects are the preferred solution to an identified issue.
PROPOSED projects are a tentative solution to an identified issue.

Note #2: The projects in this list are projected for service on the date indicated. They are expected to be needed to meet existing committments including network and native load growth. Becuase there is always the possibility of delay in permitting and construction, or for modification or deferral of projects as system conditions change, Transmission Providers should not assume that these projects are in Service when selling new transmission service. New transmission service should be conditioned on the completion of these projects.

Note # 2 above	Need Estimate (SUM =100 %)	Status (Note #1 above)	Project Group Code
[illegible]	[illegible]	[illegible]	

NONE FOR LG&E or KU

Transmission Project Construction Schedule

Current Timing

03/04 Increase the summer normal/emergency capability of the terminal facilities for circuit 6663 at Clay and at Highland to at least 425/1021A.

04/04 Increase the capability of the 345 kV terminal equipment on the Middletown 345/138 kV transformer #3 to at least 870A and increase the capability of the 138 kV terminal equipment to at least 2170A.

04/04 Increase the capability of the 345 kV terminal equipment on the Middletown 345/138 kV transformer #5 to at least 870A and increase the capability of the 138 kV terminal equipment to at least 2170A.

04/04 Replace the 300 kcm CU line wire at Clark County associated with the Clark County-Sylvania section of the Clark County-Winchester 69 kV line with 750 kcm CU equipment.

04/04 Increase the capability of the 345 kV terminal equipment on the Middletown 345/138 kV transformer #4 to at least 870A and increase the capability of the 138 kV terminal equipment to at least 2170A.

05/04 Replace the 397 kcm ACSR conductor in the Clark County-Sylvania section of the Clark County-Winchester 69 kV line with 795 kcm ACSR conductor.

05/04 Increase the maximum operating temperature of the 266 kcm ACSR conductor in the AO Smith Tap to Camargo section of the Spencer Road to Clark County 69 kV line from its confirmed 130F limit to 155F.

05/04 Increase the summer normal/emergency capability of the terminal facilities for circuit 6669 at Ethel and at Dahlia to at least 586/1019A.

05/04 Upgrade the capability of the overload relaying for circuit 6669 at Dahlia to at least 1200A.

05/04 Increase the maximum operating temperature of the 2/0 CU conductor in the Rodburn to Morehead East section of the Rodburn to Farmers 69 kV line from its confirmed 150F rating to 160F.

05/04 Replace the 600A disconnects at Etown associated with breaker 34-614 with 1200A disconnects.

05/04 Increase the maximum operating temperature of the 266 kcm ACSR conductor in the Lake Reba-Richmond 69 kV line from 176F to 212F.

05/04 Increase the maximum operating temperature of the 1033 kcm ACSR conductor in the Northside-Beargrass 138 kV line (circuit 3883) from 176F to 212F.

05/04 Increase the summer emergency capability of the metering and relaying CTs at Middletown associated with circuit 4543 to at least 1593A.

Transmission Project Construction Schedule

Current Timing

05/04 Increase the maximum operating temperature of the 1033 kcm ACSR conductor in the Jeffersonville Jct.-Beargrass section of the Northside-Beargrass 138 kV line (circuit 3882) from 176F to 212F.

05/04 Close the Cane Run Switching-Mill Creek 69 kV line.

05/04 Replace the 636 kcm ACSR conductor in the Beargrass-River City Shredding section of circuit 6651 with 1272 ACSR or equivalent conductor.

05/04 Install a 69 kV, 19.8 MVAR capacitor at Tiptop #1.

05/04 Install a 69 kV, 48.0 MVAR capacitor at Walker.

05/04 Close the Tiptop 69 kV bus tie.

05/04 Increase the maximum operating temperature of the 1033 MCM ACSR conductor in the Northside-Jeffersonville Jct. section of the Northside-Beargrass 138 kV line (circuit 3882) from 176F to 212F.

06/04 Reconductor the Middletown-Finchville 69 kV line using 397 kcm ACSR conductor.

08/04 Replace the Rodburn 138/69 kV, 33 MVA transformer with a 60 MVA transformer.

09/04 Install a 69 kV, 13.5 MVAR capacitor at Leitchfield City.

11/04 Change the setting of the 2000A metering CT at Lake Reba Tap associated with the Lake Reba Tap-JK Smith EKPC 138 kV line from 1000A to 2000A.

11/04 Change the setting of the CTs associated with breaker 102-638 and the 69 kV transformer differential CTs at Fawkes from 1200A to 1500A. Replace the 600A disconnects associated with breaker 102-718 with 1200A equipment.

11/04 Install a 69 kV, 18.0 MVAR capacitor at Middlesboro #780.

12/04 Install a third 138/69 kV, 150 MVA transformer at Middletown.

Transmission Project Construction Schedule

Current Timing	
12/04	Construct 7.5 miles of 138 kV line from Middletown to Ford using 954 kcm ACSR conductor and operate this line at 69 kV.
12/04	Replace the 1272 AA conductor in the Middletown-Aiken 69 kV line (circuit 6657) with 2000 kcm conductor or equivalent. Reconductor the six-wired 336/636 kcm ACSR with six-wired 795 kcm ACSR.
12/04	Replace the 1272 AA bus and risers at Aiken associated with the Middletown-Aiken 69 kV line (6657) with 2000 kcm equipment or equivalent. Replace the 1272 AA bus, risers, and jumpers at Middletown with 2000 kcm equipment or equivalent. Increase the CT setting on the CT at Middletown from 1200A to 1500A.
03/05	Open the Goddard 138 kV interconnection.
03/05	Remove the 5% reactor from the Kenton-Rodburn 138 kV line and install it in the remaining Spurlock-Kenton 138 kV line..
03/05	Remove the Spurlock-Kenton circuit #2 138 kV line.
03/05	Close the East Bernstadt 69 kV interconnection with EKPC by looping the Pittsburg-Lancaster 69 kV line through EKPC's East Bernstadt station.
05/05	Install a 69 kV, 42.0 MVAR capacitor at Danville North.
05/05	Replace the 69kV, 600A switch 834-625 at Danville East with 1200A equipment.
05/05	Install a 69 kV, 33.0 MVAR capacitor at Shun Pike.
05/05	Construct 4.0 miles of 138 kV line from Middletown to Bluegrass Parkway using 1272 kcm ACSR conductor.
05/05	Increase the maximum operating temperature of the 397 kcm ACSR conductor in the Paris to Detroit Harvester Tap section of the Paris to Lexington Plant 69 kV line to 212F.
05/05	Construct 6 miles of 138 kV line using 556 kcm ACSR conductor from EKPC's Avon - Renaker 138 kV line to the 69 kV breaker station at Paris and install a 138-69 kV, 150 MVA transformer.
05/05	Install a 69 kV, 30 MVAR capacitor at Boone Avenue.

Transmission Project Construction Schedule

Current Timing

05/05 Increase the setting of the relay CT at Cane Run Switching Station associated with the Cane Run #6-Cane Run Switching 138 kV line (circuit 3826) to at least 1425A.

05/05 Replace the 336 kcm ACSR conductor in the Mud Lane-Smyrna 69 kV line with 556 kcm ACSR conductor. Open Fairmount-6662 Tap and close Fairmount bus tie switch.

05/05 Upgrade the operating limit of the Adams to Delaplain section of the Adams to Renaker/Millersburg 69 kV line from 176F to 212F.

05/05 Replace the 500 kcm CU risers and line wires associated with breaker 213-604 at Boonesboro North with 750 kcm CU equipment.

05/05 Increase the maximum operating temperature of the 556 kcm ACSR conductor in the Brown North-Tyrone 138 kV line from 176F to 212F.

05/05 Increase the maximum operating temperature of the 397 kcm ACSR conductor in the Fawkes-Richmond South section of the Fawkes-Okonite 69 kV line from 176F to 212F.

05/05 Install a 69 kV, 10.8 MVAR capacitor at Metal & Thermit.

05/05 Install a 69 kV, 16.8 MVAR capacitor at Fairmount.

05/05 Install a 69 kV, 7.2 MVAR capacitor at Paint Lick.

05/05 EKPC installs a 4% reactor at Avon on the Avon-Loudon Avenue 138 kV line.

05/05 Install a 69 kV, 45.0 MVAR capacitor at West Frankfort.

05/05 Install a 69 kV, 28.8 MVAR capacitor at Bardstown.

05/05 Construct a 138 kV line exit at Hardin County for EKPC.

05/05 Increase the maximum operating temperature of the 397 kcm ACSR conductor in the Lake Reba-Berea Tap section of the Lake Reba-Okonite 69 kV line to 212F.

Transmission Project Construction Schedule

Current Timing	
05/05	Increase the maximum operating temperature of the 3/0 ACSR in the Paris-Paris 12 kV section of the Paris-Millersburg 69 kV line from 176F to 212F.
05/05	Replace the 954 mcm ACSR conductor in the Cane Run #6-Cane Run Switching 138 kV line (circuit 3826) with 1272 mcm ACSR conductor or equivalent.
05/05	Replace the 600A disconnect at Shively associated with the Shively-Farnsley 69 kV line (circuit 6637) with 1200A equipment.
05/05	Install a 69 kV, 42.0 MVAR capacitor at Farley.
05/05	Install a 69 kV, 14.4 MVAR capacitor at Tunnel Hill.
05/05	Install a 69 kV, 30.0 MVAR capacitor at Blue Lick.
05/05	Install a 69 kV, 33.0 MVAR capacitor at Rogersville.
05/05	Replace the 266 kcm ACSR conductor in the Ohio County-Rosine Jct. section of the Ohio County-Leitchfield 69 kV line with 556 kcm ACSR conductor.
05/05	Increase the maximum operating temperature of the Fawkes-Fawkes Tap section of the Fawkes-Lake Reba Tap 138 kV line from 176F to 212F
05/05	Replace the 500 MCM CU terminal equipment at Hardinsburg associated with breaker 184-724 (Hardinsburg-Hardin County 138 kV) with 750 MCM CU equipment.
11/05	Change the 1000A CT ratio on the low-side of the Blue Lick 345/161 kV transformer to 1200A.
11/05	Install a 69 kV, 16.2 MVAR capacitor at Newtown.
11/05	Install a 69 kV, 51.0 MVAR capacitor at Pineville #192.
11/05	Install a 69 kV, 33.0 MVAR capacitor at Clark County.

Transmission Project Construction Schedule

Current Timing	
11/05	Replace the 600A disconnects at Middletown associated with the Middletown-Finchville 69 kV line (circuit 6601) with 1200A equipment.
11/05	Construct 7.5 miles of 138 kV line from St. Paul to AEP's Clinch River substation using 556 kcm ACSR conductor. Install a 138/69 kV, 120 MVA transformer at St. Paul.
11/05	Replace 600A breaker 116-604 at St. Paul (associated with the St. Paul-Bond 69 kV line) with a 1200A breaker.
05/06	Install a 138/69 kV, 150 MVA transformer at Danville North.
05/06	Replace the 500 kcm Cu bus associated with breaker 66-734 at Higby Mill with 750 kcm Cu.
05/06	Install a 69 kV line exit at Lebanon and construct 1.2 miles of 69 kV line from Lebanon to Lebanon Industrial using 397 kcm ACSR conductor.
05/06	Install a second 138-69 kV, 150 MVA transformer at Fawkes.
05/06	Reconductor the 397 kcm ACSR conductor in the Madisonville South Tap to McCoy Avenue section of the Madisonville loop with 556 kcm ACSR.
05/06	Replace the 300 kcm Cu bus, risers and line wire associated with breaker 69-604 at Richmond with 500 kcm Cu equipment.
05/06	Install a 69 kV, 26.4 MVAR capacitor at the KU Hodgenville #744 station.
05/06	Replace the West Cliff 138/69 kV, 93 MVA transformer with a 120 MVA transformer.
05/06	Reconductor the 266 kcm ACSR conductor in the Etown-Etown #5 69 kV line section using 397 kcm ACSR conductor.
05/06	Replace the 4/0 Cu wire associated with the air-break switch 847-615 in the Lexington Plant-Buchanan section of the Lexington Plant-Pisgah 69 kV line with 300 MCM Cu equipment.
05/06	Increase the maximum operating temperature of the 397 kcm ACSR conductor in the Sweet Hollow-North Corbin section of the Sweet Hollow-London 69 kV line to 212F.

Transmission Project Construction Schedule

Current Timing	
05/06	Install a fourth 345/138 kV, 450 MVA transformer at Middletown.
05/06	Increase the size of the London 69 kV capacitor to 30.6 MVARs.
05/06	Construct 4.2 miles of 69 kV line from Loudon Avenue to the Lakeshore/Bryant Road tap using 795 kcm ACSR conductor. Serve the Lakeshore and Bryant Road loads radially from this line.
05/06	Construct 1.5 miles of 69 kV line from Lebanon Industrial to Lebanon City using 397 kcm ACSR conductor. Serve Lebanon City on this radial from Lebanon.
05/06	Install a 69 kV, 64.8 MVAR capacitor at Dahlia.
05/06	Install a 69 kV, 18.0 MVAR capacitor at Cynthiana South.
05/06	Install a 69 kV, 33.6 MVAR capacitor at River Queen.
05/06	Install a 12.0 MVAR capacitor at Olin Corp.
11/06	Install a 69 kV, 6.6 MVAR capacitor at Pineville #722.
11/06	Construct 3.5 miles of 69 kV line from Pineville #722 to the Pineville to Calloway section of the Pineville to Rocky Branch 69 kV line using 556 kcm ACSR conductor. Operate Pineville #722 from the Pineville to Calloway 69 kV line section.
11/06	Replace the 600A disconnects associated with breaker 102-614 at Fawkes with 1200A equipment.
11/06	Replace the 556 kcm ACSR conductor in the Fawkes KU-Fawkes EKPC Tap section of the Fawkes-Lake Reba Tap 138 kV line with 795 kcm ACSR.
11/06	Install a 69 kV, 26.4 MVAR capacitor at Scott County.
11/06	Increase the winter emergency capability of the terminal equipment associated with the Pocket North-Pocket 161 kV line to at least 665A.

Transmission Project Construction Schedule

Current Timing	
11/06	Replace the 1200A breaker 184-724 and associated wave trap at Hardinsburg and the 1200A breaker 178-714 and associated wave trap at Hardin County with 1600A equipment or higher.
11/06	Install a 69 kV, 28.8 MVAR capacitor at Versailles.
05/07	Construct 0.77 miles of 69 kV line from Danville North to the Atoka Tap using 397 kcm ACSR conductor utilizing available double circuit space on the Boyle Co to Danville North 69 kV line. Construct 2 miles of 69 kV line using 397 kcm ACSR from the Atoka Tap line to Minor Farm. Operate as a radial.
05/07	Replace the 600A air break switch 677-605 at Wilmore with a 1200A switch.
05/07	Replace the 600A disconnects associated with breaker 101-604 (Boyle County-Lancaster 69 kV line) at Boyle Co with 1200A equipment.
05/07	Install a third 138/69 kV, 112 MVA transformer at East Frankfort (use the spare 112 MVA removed from Loudon Avenue). Reconfigure the bus such that two transformers and two lines to Frankfort City stay in service during any contingency.
05/07	Increase the maximum thermal operating limit of the Kentucky State Hospital-Danville East section of the West Cliff-Boyle County 69 kV line to 212 degrees F.
05/07	Replace the 300 kcm Cu transformer wires associated with breakers 96-608 and 96-618 at Elihu with 500 kcm Cu wires.
05/07	Replace the 397 kcm ACSR conductor in the Sylvania-Parker Seal section of the Clark County-Winchester 69 kV line with 795 kcm ACSR conductor.
05/07	Replace the 600A bus and line CTs associated with breaker 199-624 at Winchester with 1200A equipment.
05/07	Change the setting of the 600A bus-side CT associated with breaker 18-614 at Spencer Road from 400A to 600A.
05/07	Replace the Spencer Road 138/69 kV, 56 MVA transformer with a 93 MVA transformer.
05/07	Replace the 600A disconnects 199-624B and 199-624L at Winchester with 1200A disconnects.
05/07	Replace the 266 kcm ACSR conductor in the Parkers Mill Tap-Parkers Mill section of the line tapping the Pisgah-Lexington Plant 69 kV line with 397 kcm ACSR conductor.

Transmission Project Construction Schedule

Current Timing

05/07 Change the setting of the 1200A line CT associated with breaker 135-604 at Clark County from 600A to 1200A. Replace the 500 MCM Cu bus and wires at Clark County with 750 MCM Cu equipment.

05/07 Construct 1.6 miles of 69 kV line from Ewington to AO Smith using 397 kcm ACSR conductor. Operate Ewington and AO Smith radially from Spencer Road.

05/07 Replace the 300 MCM Cu risers and line wire associated with breaker 199-624 at Winchester with 500 MCM Cu equipment.

05/07 Replace the Spencer Road 138/69 kV, 33 MVA transformer with a 93 MVA transformer. (Use the transformer removed from West Cliff). Operate the two transformers at Spencer Road in parallel.

05/07 Replace the bundled 1/0 Cu conductor in the Lexington Plant-Buchanan section of the Lexington Plant-Pisgah 69 kV line with 556 kcm ACSR conductor.

05/07 Replace the 4/0 Cu wire at Buchanan associated with the Buchanan-West High Tap section of the Lexington Plant-Pisgah 69 kV line with 300 MCM Cu equipment.

05/07 Increase the maximum operating temperature of the 266 kcm ACSR conductor in the Etown-Etown #2 Tap section of the Etown-Rogersville 69 kV line to 212F.

05/07 Install a 69 kV, 45 MVAR capacitor at Harrods Creek.

05/07 Replace the 600A disconnects associated with breaker 101-634 at Boyle County (Boyle County-Danville North 69 kV line) with 1200A equipment.

05/07 Increase the maximum operating temperature of the 266 kcm ACSR conductor in the Boyle County-Danville #1 section of the Boyle County-West Cliff 69 kV line from 176F to 212F.

05/07 Increase the setting of the meter CT associated with breaker 68-634 at Bonds Mill (Bonds Mill-North Springfield EKPC) from 600A to 800A.

05/07 Increase the maximum operating temperature of the 636 kcm ACSR conductor in the Mill Creek-Manslick 138 kV line (circuit 3834) from 176F to 180F.

05/07 Replace the 800A wave trap at Tyrone associated with the Brown North-Tyrone 138 kV line with a 1200A wave trap.

05/07 Increase the maximum verified operating temperature of the AO Smith Tap-Camargo section of the Spencer Road-Clark County 69 kV line to 212F.

Transmission Project Construction Schedule

Current Timing	
05/07	Increase the size of the Eminence capacitor to 28.8 MVARs.
05/07	Install a 69 kV, 24.3 MVAR capacitor at Bardstown Industrial.
11/07	Install a 69 kV, 9.1 MVAR capacitor at Science Hill.
11/07	Replace breaker 18-614 at Spencer Road with a 1200A breaker.
11/07	Increase the maximum operating limit of the 266 kcm ACSR conductor in the Lake Reba-Waco section of the Lake Reba-West Irvine 69 kV line from 176F to 212F.
11/07	Increase the overload relay setting at Eastwood associated with the Eastwood-Simpsonville section of the Eastwood-Shelbyville 69 kV line from 720A to 840A.
11/07	Replace the 1200A breaker (102-724) and associated wave trap at Fawkes associated with the Fawkes-Lake Reba Tap 138 kV line with 1600A equipment.
11/07	Replace the 1200A meter CT at Fawkes associated with the Fawkes-Fawkes EKPC 138 kV line with 1600A equipment.
11/07	Replace the 161 kV, 800A wave trap associated with the Lake Reba Tap 161/138 kV transformer.
11/07	Replace the 600A meter CT at Etown associated with breaker 34-614 (Etown-Tharp EKPC 69 kV line) with equipment with a winter emergency capability of at least 967A.
11/07	Replace the 600A disconnects at Eastwood associated with the 6658 Tap-Eastwood section of circuit 6658 with 1200A equipment.
05/08	Construct 19 miles of 138 kV line from Brown CT to Danville North using 954 kcm ACSR conductor.
05/08	Replace the 138/69 kV, 93 MVA transformer at Bardstown with a 120 MVA transformer.
05/08	Reset the breaker CT on the transformer side of breaker 135-608 at Clark County from 600A to 1200A.

Transmission Project Construction Schedule

Current Timing

05/08 Increase the rating of the Taylor County - Mile Lane section of the Taylor County to Green County 69 kV line by increasing the maximum operating temperature of the 266.8 kcm ACSR conductor to 212F.

05/08 Install a second 345/138 kV, 450 MVA transformer at Hardin County.

05/08 Increase the maximum operating temperature of the 397.5 kcm ACSR conductor in the Pineville to Pineville #722 section of the Pineville to Middlesboro 69 kV line to 100C.

05/08 Increase the CT ratio at Seminole for the Seminole to Floyd to Locust 69 kV line (6647) to 1200A.

05/08 Replace the 300 MCM Cu wires associated with breaker 34-614 at Etown with 500 MCM Cu equipment.

11/08 Replace the 69 kV, 600A switch 312-625 at Clinch Valley with a 1200A switch.

11/08 Replace the 336 MCM ACSR conductor in the Eastwood-Simpsonville section of the Eastwood-Shelbyville 69 kV line using 397 kcm ACSR conductor.

11/08 Move the Lebanon City 69 kV capacitor to Lebanon and increase the size to 28.8 MVars.

11/08 Replace the 500 MCM Cu bus at Fawkes associated with the Fawkes-Lake Reba Tap 138 kV line with 750 MCM Cu bus or equivalent.

11/08 Install a 69 kV, 13.5 MVAR capacitor at Williamsburg South.

11/08 Replace the 1200A breaker 213-608 at Boonesboro North associated with the Boonesboro North 138/69 kV transformer with a 1600A breaker.

05/09 Replace the 800A wave trap associated with breaker 152-724 at Brown North (Brown North-Pisgah 138 kV) with a 1200A wave trap.

05/09 Reconductor the Horse Cave Tap 69 kV line with 397.5 kcm ACSR conductor.

05/09 Reconductor the Dix Dam-Wilmore Tap section of the Dix Dam-Higby Mill 69 kV line with 556 kcm ACSR conductor.

Transmission Project Construction Schedule

Current Timing

05/09 Increase the maximum operating temperature of the 397 kcm ACSR conductor in the Bardstown-Bardstown Industrial Tap section of the Bardstown-East Bardstown EKPC 69 kV line from 80C to 100C.

05/09 Increase the maximum operating temperature of the 397 kcm ACSR conductor in the Etown to Etown #4 section of the Etown to Hodgenville EKPC 69 kV line to 212F.

05/09 Replace the 750 kcm CU line wire at West Cliff and the 750 kcm CU bus and line wire at Dix Dam associated with the West Cliff-Dix Dam 69 kV line with 1000 kcm CU equipment.

05/09 Reconductor the Middletown to Plainview Tap section of the Middletown to Beargrass 138 kV line with 1272 ACSR conductor.

05/09 Convert the Middletown-Ford 69 kV line to 138 kV and install a 138/69 kV, 150 MVA transformer at Ford.

05/09 Increase the maximum operating temperature of the 397 kcm ACSR conductor in the North Madison EKPC-Spears B section of the Fawkes-Higby Mill 69 kV line from 150F to 155F.

05/09 Increase the maximum operating temperature of the 500 kcm Cu conductor in the Blue Lick-Bullitt County 161 kV line from 176F to 212F.

05/09 Increase the capability of the metering and relaying CTs at Mill Creek associated with circuit 3855 to at least 300A.

05/09 Replace the 138/69 kV, 112 MVA transformer at Higby Mill between breakers 66-708 and 66-608 with a 150 MVA transformer.

05/09 Replace the 397 kcm ACSR conductor in the Fawkes-Richmond South section of the Fawkes-Okonite 69 kV line using 556 kcm ACSR conductor.

05/09 Increase the maximum unverified operating temperature of the 397 kcm ACSR conductor in the Elihu-Somerset #3 section of the Elihu (96-624)-Somerset North 69 kV line from 176F to 212F.

05/09 Install a third 138/69 kV, 60 MVA transformer at Carrollton.

05/09 Increase the maximum operating temperature of the #2 1X Cu conductor in the Lawrence Tap-Lawrence section of the Carrollton-Eminence 69 kV line from 176F to 212F.

05/09 Change the setting of the bus CT at Boyle County associated with the Boyle County-Danville North 69 kV line from 600A to at least 800A.

Transmission Project Construction Schedule

Current Timing

05/09 Replace the 600A disconnect 676-2 in the 6676 Tap-Blue Lick RECC section of the South Park-Mud Lane 69 kV line (circuit 6676) with 1200A equipment.

05/09 Increase the maximum operating temperature of the 795 MCM AA conductor in the Watterson-Nachand 69 kV line (circuit 6667) from 176F to 212F.

05/09 Install a 69 kV, 12.6 MVAR capacitor at Hunters Bottom.

05/09 Install a second 138/69 kV, 120 MVA transformer at Algonquin.

05/09 Change the CT settings associated with breaker 155-714 at Bardstown (Bardstown-Brown CT) from 600A to 800A.

05/09 Replace the 397 kcm ACSR conductor in the Vaksdahl Avenue-Danville Industrial Tap section of the Boyle County-Lancaster 69 kV line with 556 kcm ACSR conductor.

05/09 Increase the maximum operating temperature of the Fawkes Tap-Lake Reba Tap section of the Fawkes-Lake Reba Tap 138 kV line from 176F to 212F.

11/09 Replace the Pineville 161/69 kV, 93 MVA transformer with a 120 MVA unit.

11/09 Change the setting of the 1200A line CT on breaker 71-624 at Imboden from 600A to 800A.

11/09 Install a 69 kV, 6.0 MVAR capacitor at Union Underwear.

11/09 Change the setting of the 161 kV bus CT associated with breaker 162-804 at Lake Reba Tap from 600A to 800A.

11/09 Change the setting of the bus CT on breaker 65-624 at Tyrone from 600A to 800A.

11/09 Change the setting of the bus CT associated with breaker 162-724 at Lake Reba Tap from 1200A to 1500A.

11/09 Reconductor the 266 kcm ACSR conductor in the Lake Reba-Waco section of the Lake Reba-West Irvine 69 kV line with 397 kcm ACSR conductor.

Transmission Project Construction Schedule

Current Timing	
11/09	Change the CT setting of the bus CT associated with breaker 162-804 at Lake Reba Tap from 600A to 800A.
11/09	Change the CT settings at Fawkes and Richmond associated with the Fawkes-Richmond 69 kV line from 800A to 1000A.
12/09	Construct approximately 43 miles of 345 kV line from Mill Creek to Hardin County using bundled 954 kcm ACSR conductor.
12/09	Construct 11.8 miles of 138 kV line between West Lexington and Higby Mill using 556 kcm ACSR conductor.
12/09	Construct 10.2 miles of 138 kV line between West Frankfort and Tyrone using 795 kcm ACSR conductor.
12/09	Reconductor the Ghent-Owen County Tap section of the Ghent-Scott County 138 kV line using 954 kcm ACSR conductor.
12/09	Construct a 138 kV line between Etown and Hardin County using 795 kcm ACSR conductor.
12/09	Install two 345 kV line exits at Trimble Co and build 2.8 miles of double circuit 345 kV line to Cinergy's Ghent to Speed 345 kV line.
05/10	Replace the 1200A disconnects 178-718T and 178-718B at Hardin County with 2000A equipment.
05/10	Replace the 500 kcm CU bus and line wire at Etown associated with the Hardin County-Etown 138 kV line with 750 kcm CU equipment.
05/10	Replace breaker 127-638 at Haefling associated with the Haefling 138/69 kV transformer with 1600A equipment. Reset the low-side transformer CT to 1300A.
05/10	Increase the maximum operating temperature of the 795 kcm ACSR conductor in the P&G-Race Street section of the Lexington Plant-Race Street 69 kV line from 130F to 135F.
05/10	Replace the 1033 kcm ACSR conductor in the Northside-Jeffersonville Jct. section of the Northside-Beargrass 138 kV line (circuit 3882) with bundled 954 kcm ACSR conductor.
05/10	Install a 69 kV, 39.6 MVAR capacitor at Paris.

Transmission Project Construction Schedule

Current Timing	
05/10	Replace the 397 kcm ACSR conductor in the Laurel County EKPC-Hopewell section of the Laurel County EKPC-Sweet Hollow 69 kV line using 556 kcm ACSR.
05/10	Install a 69 kV, 16.8 MVAR capacitor at Delaplain.
11/10	Install a 69 kV, 23.4 MVAR capacitor at Gorge.
05/11	Replace the 138-69 kV, 112 MVA transformer at Danville North with a 150 MVA transformer.
05/11	Upgrade the maximum operating temperature of the conductor in the Carrolton to Metal Thermistor section of the Carrollton to Owen Co 69 kV line from 176F to 212F.
05/11	Install a 138/69 kV, 120 MVA transformer at Hardin County.
05/11	Increase the maximum operating temperature of the 266 kcm ACSR conductor in the Somerset EKPC to Somerset South section of the Somerset EKPC-Sewellton EKPC 69 kV line to 100C.
05/11	Replace the 161/69 kV, 56 MVA transformer at Taylor County with a 90 MVA unit.
05/11	Replace the 2000 kcm AA underground conductor in the Ethel-Dahlia 69 kV line (circuit 6669) with overhead 954 kcm ACSR.
05/11	Increase the size of the Bardstown City capacitor by 2.4 MVARs.
05/12	Install 138 kV breakers on the Lebanon 138-69 kV transformers.
05/12	Replace the 138/69 kV, 93 MVA transformer at Clark County with a 150 MVA transformer.
05/12	Increase the maximum operating temperature of the 266 kcm ACSR conductor in the Greensburg-Campbellsville EKPC section of the Green County EKPC-Taylor County 69 kV line from 176F to 200F.
05/12	Replace the 1033 kcm ACSR conductor in the Northside-Beargrass 138 kV line (circuit 3883) with bundled 954 kcm ACSR conductor.

Transmission Project Construction Schedule

Current Timing	
05/12	Install 138 kV breakers at Pisgah and install a second Pisgah 138/69 kV, 112 MVA transformer. (Use transformer removed from Higby Mill).
05/12	Close switch 609-605 at Delaplain to operate the Delaplain-Delaplain Tap 69 kV line section normally-closed.
05/12	Construct a 69 kV circuit from Middletown to Collins using the open circuit on the Middletown to Ford double-circuit towers.
11/12	Replace the 161-69 kV, 56 MVA transformer at Beattyville with a 90 MVA unit.
11/12	Energize the second Brown North-Pineville 345 kV circuit.
05/13	Install a second 345/138 kV, 450 MVA transformer at Brown North
05/13	Reconductor the 266 kcm ACSR conductor in the Adams to Toyota South 138 kV line with 556 kcm ACSR conductor.
05/13	Reconductor the 266 kcm ACSR conductor in the Green County EKPC-Greensburg KU section of the Green County EKPC-Taylor County 69 kV line using 397 kcm ACSR conductor.
05/13	Increase the maximum operating temperature of the 636 kcm ACSR conductor in the Oxmoor to Breckenridge 69 kV line (6653) to 100C.
05/13	Increase the CT ratios at Oxmoor and Breckenridge for the Oxmoor to Breckenridge 69 kV line (6653) to 1200A.
05/13	Replace the 600A disconnects associated with breaker 66-644 at Higby Mill with 1200A disconnects.
05/13	Install a 69 kV, 18 MVAR capacitor at Camargo.
05/13	Replace the 1200A disconnects associated with breaker 176-714 at Loudon Avenue with 1600A equipment.
05/13	Replace the 266 kcm ACSR conductor in the Adams-Delaplain Tap section of the Adams-Millersburg 69 kV line with 397 kcm ACSR conductor.

Transmission Project Construction Schedule

Current Timing	
05/13	Construct 2 miles of 138 kV line from Kosmos Cement to Knob Creek and install three 138 kV breakers at Knob Creek.
05/13	Reconductor the Avon EKPC-Loudon Avenue 138 kV line using bundled 556 kcm ACSR conductor.
05/13	Replace the 1000 MCM Cu bus at Loudon Avenue associated with the Avon EKPC-Loudon Avenue 138 kV line with 2" AL tube or equivalent.
05/13	Replace the 266 kcm ACSR conductor in the Rosine Jct.-Caneyville Jct. section of the Ohio County-Leitchfield 69 kV line with 556 kcm ACSR conductor.