The Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for the Construction of a 345 kV Electric Transmission Project in Clark, Madison and Garrard Counties, Kentucky – Responses to PSC Staff's First Data Request dated 7/6/07

PSC Case No. 2006-00463

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

JUL 16 2007

PUBLIC SERVICE
COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY	)	
POWER COOPERATIVE, INC. FOR A	)	
CERTIFICATE OF PUBLIC CONVENIENCE	)	
AND NECESSITY FOR OR THE CONSTRUCTION	)	**CASE NO. 2006-00463**
OF A 345 kV PROJECT IN CLARK, MADISON	)	
AND GARRARD COUNTIES, KENTUCKY	)	

APPLICANT'S RESPONSE TO COMMISSION STAFF'S FIRST DATA REQUEST DATED JULY 6, 2007

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2006-00463

INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007

REQUEST NO. 1

RESPONDING PERSON: DARRIN ADAMS

Request 1: Provide a transmission map of the EKPC and surrounding power systems, depicting transmission system facilities by voltage level.

Response: This document is the subject of the Applicant's Petition for Confidential Treatment and is included as **Data Request 1 Exhibit A** in that Petition filed this date.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2006-00463
INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007
REQUEST NO. 2
RESPONDING PERSON: BRANDON GRILLON

Request 2: Provide the Kentucky Transmission Line Siting Project Report.

Response: This Kentucky Transmission Line Siting Project Report contains such graphics and volume that it is included with this filing on CD-Rom labeled **Response to Staff's Data Request 2**, Kentucky Siting Model.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2006-00463

INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007

REQUEST NO. 3

RESPONDING PERSON: DARRIN ADAMS

Request 3: Provide a transmission map of the East Central Area Reliability ("ECAR") region.

Response: This document is the subject of the Applicant's Petition for Confidential Treatment and is included as **Data Request 3 Exhibit A** in that Petition filed this date.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2006-00463
INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007
REQUEST NO. 4
RESPONDING PERSON: DARRIN ADAMS

Request 4: Provide one-line breaker diagrams for the Avon, North Clark, and West Garrard 345 kV Substations.

Response: This document is the subject of the Applicant's Petition for Confidential Treatment and is included as **Request 4 Exhibit A, B and C** in that Petition filed this date.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2006-00463
INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007
REQUEST NO. 5
RESPONDING PERSON: JULIA J. TUCKER

Request 5: Supply a list of generating stations with over 100 MW of capability within an approximate 100-mile radius of the J. K. Smith Generating Station. Identify each unit at the station by number, summer and winter net capability, fuel source, and type (i.e., base, cycling, etc.).

Response: A list of generating stations with over 100 MW of capability within an approximate 100-mile radius of the J. K. Smith Generating Station is attached as **Request 5 Exhibit A.**

RESPONSE TO STAFF'S DATA
REQUEST EXHIBIT A

Plant Operator Name	Plant Name	Unit	Summer Capacity MW	Winter Capacity MW	Primary Fuel Category	Primary Fuel Code	Prime Mover Category	Prime Mover Code	Nameplate Capacity MW
Appalachian Power Co	Mountaineer	1	1300	1300	Coal	BIT	ST	ST	1300
Ohio Power Co	Gavin	1	1300	1300	Coal	BIT	ST	ST	1300
Ohio Power Co	Gavin	2	1300	1300	Coal	BIT	ST	ST	1300
Tennessee Valley Authority	Bull Run (TN)	1	881	885	Coal	BIT	ST	ST	950
Appalachian Power Co	John E Amos	3	915.59	915.59	Coal	BIT	ST	ST	915.59
Kentucky Power Co	Big Sandy	2	800	800	Coal	BIT	ST	ST	816.3
Duke Energy Ohio	W H Zimmer	ST1	604.5	604.5	Coal	BIT	ST	ST	662.904
Duke Energy Hanging Rock LLC	Hanging Rock Energy Facility	CC1	570	620	Gas	NG	CC	CC	644
Duke Energy Hanging Rock LLC	Hanging Rock Energy Facility	CC2	570	620	Gas	NG	CC	CC	644
AEP Generating Co	Lawrenceburg Energy	CC1	541	542	Gas	NG	CC	CC	616
AEP Generating Co	Lawrenceburg Energy	CC2	547	591	Gas	NG	CC	CC	616
Indiana Michigan Power Co	Tanners Creek	4	500	500	Coal	BIT	ST	ST	579.7
Appalachian Power Co	John E Amos	1	563.44	563.44	Coal	BIT	ST	ST	574.92
Appalachian Power Co	John E Amos	2	563.44	563.44	Coal	BIT	ST	ST	574.92
Kentucky Utilities Co	Ghent	1	475	468	Coal	BIT	ST	ST	556.9
Kentucky Utilities Co	Ghent	3	493	495	Coal	BIT	ST	ST	556.5
Kentucky Utilities Co	Ghent	2	484	466	Coal	BIT	ST	ST	556.3
Kentucky Utilities Co	Ghent	4	493	495	Coal	BIT	ST	ST	556.2
Louisville Gas & Electric Co	Mill Creek (KY)	4	477	492	Coal	BIT	ST	ST	543.6
East Kentucky Power Coop	Hugh L Spurlock	2	525	525	Coal	BIT	ST	ST	508.2
Louisville Gas & Electric Co	Mill Creek (KY)	3	391	397	Coal	BIT	ST	ST	462.6
Duke Energy Kentucky	East Bend	2	414	414	Coal	BIT	ST	ST	461.817
Dayton Power & Light Co (The)	Killen Station	2	402	402	Coal	BIT	ST	ST	446.488
Kentucky Utilities Co	E W Brown	3	429	433	Coal	BIT	ST	ST	446.3
Louisville Gas & Electric Co	Trimble Station (LGE)	1	383.325	386.25	Coal	BIT	ST	ST	424.575
Duke Energy Ohio	W H Zimmer	ST1	365.3	365.3	Coal	BIT	ST	ST	400.594
Appalachian Power Co	John E Amos	3	384.41	384.41	Coal	BIT	ST	ST	384.41
Duke Energy Ohio	W H Zimmer	ST1	330.2	330.2	Coal	BIT	ST	ST	362.102
Appalachian Power Co	Phil Sporn	5	318.56	325.8	Coal	BIT	ST	ST	358.742
Duke Energy Ohio	Miami Fort	8	320	320	Coal	BIT	ST	ST	356.928
Duke Energy Ohio	Miami Fort	7	320	320	Coal	BIT	ST	ST	356.544
Louisville Gas & Electric Co	Mill Creek (KY)	1	303	303	Coal	BIT	ST	ST	355.5
Louisville Gas & Electric Co	Mill Creek (KY)	2	301	299	Coal	BIT	ST	ST	355.5
East Kentucky Power Coop	Hugh L Spurlock	3	268	278	Coal	BIT	ST	AB	329.4
East Kentucky Power Coop	Hugh L Spurlock	1	325	325	Coal	BIT	ST	ST	305.2

Source: Global Energy Decisions

Plant Operator Name	Plant Name	Unit	Summer Capacity MW	Winter Capacity MW	Primary Fuel Category	Primary Fuel Code	Prime Mover Category	Prime Mover Code	Nameplate Capacity MW
Kentucky Power Co	Big Sandy	1	260	260	Coal	BIT	ST	ST	280.5
Louisville Gas & Electric Co	Cane Run	6	240	240	Coal	BIT	ST	ST	272
Duke Energy Ohio	Walter C Beckjord	5	238	238	Coal	BIT	ST	ST	244.8
Appalachian Power Co	John E Amos	1	236.56	236.56	Coal	BIT	ST	ST	241.38
Appalachian Power Co	John E Amos	2	236.56	236.56	Coal	BIT	ST	ST	241.38
Dayton Power & Light Co (The)	J M Stuart	1	228.15	228.15	Coal	BIT	ST	ST	237.978
Dayton Power & Light Co (The)	J M Stuart	2	228.15	228.15	Coal	BIT	ST	ST	237.978
Dayton Power & Light Co (The)	J M Stuart	3	228.15	228.15	Coal	BIT	ST	ST	237.978
Dayton Power & Light Co (The)	J M Stuart	4	228.15	228.15	Coal	BIT	ST	ST	237.978
Appalachian Power Co	Clinch River	1	230	235	Coal	BIT	ST	ST	237.5
Appalachian Power Co	Clinch River	2	230	235	Coal	BIT	ST	ST	237.5
Appalachian Power Co	Clinch River	3	230	235	Coal	BIT	ST	ST	237.5
Duke Energy Ohio	Walter C Beckjord	6	207	210.5	Coal	BIT	ST	ST	230.4
Riverside Generating Co LLC	Riverside Generating Co LLC	GTG4	165	190	Gas	NG	GT	GT	230
Riverside Generating Co LLC	Riverside Generating Co LLC	GTG5	165	190	Gas	NG	GT	GT	230
Riverside Generating Co LLC	Riverside Generating Co LLC	GTG1	165	190	Gas	NG	GT	GT	230
Riverside Generating Co LLC	Riverside Generating Co LLC	GTG2	165	190	Gas	NG	GT	GT	230
Riverside Generating Co LLC	Riverside Generating Co LLC	GTG3	165	190	Gas	NG	GT	GT	230
East Kentucky Power Coop	J Sherman Cooper	2	225	225	Coal	BIT	ST	ST	220.8
Dayton Power & Light Co (The)	Killen Station	2	198	198	Coal	BIT	ST	ST	219.912
Indiana Kentucky Electric Corp	Clifty Creek	1	199.3	205	Coal	SUB	ST	ST	217.2
Indiana Kentucky Electric Corp	Clifty Creek	2	199.3	205	Coal	SUB	ST	ST	217.2
Indiana Kentucky Electric Corp	Clifty Creek	3	199.3	205	Coal	SUB	ST	ST	217.2
Indiana Kentucky Electric Corp	Clifty Creek	4	199.3	205	Coal	SUB	ST	ST	217.2
Indiana Kentucky Electric Corp	Clifty Creek	5	199.3	205	Coal	SUB	ST	ST	217.2
Indiana Kentucky Electric Corp	Clifty Creek	6	199.3	205	Coal	SUB	ST	ST	217.2
Ohio Valley Electric Corp	Kyger Creek	1	198.5	205	Coal	BIT	ST	ST	217.2
Ohio Valley Electric Corp	Kyger Creek	2	196.8	204.5	Coal	BIT	ST	ST	217.2
Ohio Valley Electric Corp	Kyger Creek	3	196.8	204.5	Coal	BIT	ST	ST	217.2
Ohio Valley Electric Corp	Kyger Creek	4	196.8	204.5	Coal	BIT	ST	ST	217.2
Ohio Valley Electric Corp	Kyger Creek	5	196.8	204.5	Coal	BIT	ST	ST	217.2
Indiana Michigan Power Co	Tanners Creek	3	200	205	Coal	BIT	ST	ST	215.4
Dayton Power & Light Co (The)	J M Stuart	1	204.75	204.75	Coal	BIT	ST	ST	213.57
Dayton Power & Light Co (The)	J M Stuart	2	204.75	204.75	Coal	BIT	ST	ST	213.57
Dayton Power & Light Co (The)	J M Stuart	3	204.75	204.75	Coal	BIT	ST	ST	213.57

Source: Global Energy Decisions

Plant Operator Name	Plant Name	Unit	Summer Capacity MW	Winter Capacity MW	Primary Fuel Category	Primary Fuel Code	Prime Mover Category	Prime Mover Code	Nameplate Capacity MW
Dayton Power & Light Co (The)	J M Stuart	4	204.75	204.75	Coal	BIT	ST	ST	213.57
Louisville Gas & Electric Co	Cane Run	5	168	168	Coal	BIT	ST	ST	209.4
Bluegrass Generation Co LLC	Bluegrass Generation Co LLC	CT1	160	208	Gas	NG	GT	GT	208
Bluegrass Generation Co LLC	Bluegrass Generation Co LLC	CT2	160	208	Gas	NG	GT	GT	208
Bluegrass Generation Co LLC	Bluegrass Generation Co LLC	CT3	160	208	Gas	NG	GT	GT	208
Duke Energy Kentucky	East Bend	2	186	186	Coal	BIT	ST	ST	207.483
Duke Energy Ohio	Miami Fort	8	180	180	Coal	BIT	ST	ST	200.772
Duke Energy Ohio	Miami Fort	7	180	180	Coal	BIT	ST	ST	200.556
Tennessee Valley Authority	John Sevier	1	176	178	Coal	BIT	ST	ST	200
Tennessee Valley Authority	John Sevier	2	176	178	Coal	BIT	ST	ST	200
Tennessee Valley Authority	John Sevier	3	176	178	Coal	BIT	ST	ST	200
Tennessee Valley Authority	John Sevier	4	176	178	Coal	BIT	ST	ST	200
Tennessee Valley Authority	Kingston	5	177	179	Coal	BIT	ST	ST	200
Tennessee Valley Authority	Kingston	6	177	179	Coal	BIT	ST	ST	200
Tennessee Valley Authority	Kingston	7	177	179	Coal	BIT	ST	ST	200
Tennessee Valley Authority	Kingston	8	177	179	Coal	BIT	ST	ST	200
Tennessee Valley Authority	Kingston	9	178	180	Coal	BIT	ST	ST	200
Kentucky Utilities Co	E W Brown	2	167	169	Coal	BIT	ST	ST	179.5
Tennessee Valley Authority	Kingston	1	135	138	Coal	BIT	ST	ST	175
Tennessee Valley Authority	Kingston	2	135	138	Coal	BIT	ST	ST	175
Tennessee Valley Authority	Kingston	3	135	138	Coal	BIT	ST	ST	175
Tennessee Valley Authority	Kingston	4	135	138	Coal	BIT	ST	ST	175
Western Kentucky Energy Corp	Kenneth Coleman	GEN1	150	150	Coal	BIT	ST	ST	174.2
Western Kentucky Energy Corp	Kenneth Coleman	GEN2	150	150	Coal	BIT	ST	ST	174.2
Duke Energy Ohio	Walter C Beckjord	6	155.25	157.875	Coal	BIT	ST	ST	172.8
Western Kentucky Energy Corp	Kenneth Coleman	GEN3	155	155	Coal	BIT	ST	ST	172.8
Duke Energy Ohio	Miami Fort	6	163	163	Coal	BIT	ST	ST	163.2
Duke Energy Ohio	Walter C Beckjord	4	150	150	Coal	BIT	ST	ST	163.2
Louisville Gas & Electric Co	Cane Run	4	155	155	Coal	BIT	ST	ST	163.2
Dynegy Operating Co	Rolling Hills Generating LLC	CT1	160	160	Gas	NG	GT	GT	160
Dynegy Operating Co	Rolling Hills Generating LLC	CT2	160	160	Gas	NG	GT	GT	160
Dynegy Operating Co	Rolling Hills Generating LLC	CT3	160	160	Gas	NG	GT	GT	160
Dynegy Operating Co	Rolling Hills Generating LLC	CT4	160	160	Gas	NG	GT	GT	160
Dynegy Operating Co	Rolling Hills Generating LLC	CT5	160	160	Gas	NG	GT	GT	160
Dayton Power & Light Co (The)	J M Stuart	1	152.1	152.1	Coal	BIT	ST	ST	158.652

Source: Global Energy Decisions

Plant Operator Name	Plant Name	Unit	Summer Capacity MW	Winter Capacity MW	Primary Fuel Category	Primary Fuel Code	Prime Mover Category	Prime Mover Code	Nameplate Capacity MW
Dayton Power & Light Co (The)	J M Stuart	2	152.1	152.1	Coal	BIT	ST	ST	158.652
Dayton Power & Light Co (The)	J M Stuart	3	152.1	152.1	Coal	BIT	ST	ST	158.652
Dayton Power & Light Co (The)	J M Stuart	4	152.1	152.1	Coal	BIT	ST	ST	158.652
Indiana Michigan Power Co	Tanners Creek	1	145	145	Coal	BIT	ST	ST	152.5
Indiana Michigan Power Co	Tanners Creek	2	140	145	Coal	BIT	ST	ST	152.5
Duke Energy Indiana	R Gallagher	1	140	140	Coal	BIT	ST	ST	150
Duke Energy Indiana	R Gallagher	2	140	140	Coal	BIT	ST	ST	150
Duke Energy Indiana	R Gallagher	3	140	140	Coal	BIT	ST	ST	150
Duke Energy Indiana	R Gallagher	4	140	140	Coal	BIT	ST	ST	150
East Kentucky Power Coop	JK Smith	1	110	150	Gas	NG	GT	GT	149
East Kentucky Power Coop	JK Smith	2	110	150	Gas	NG	GT	GT	149
East Kentucky Power Coop	JK Smith	3	110	150	Gas	NG	GT	GT	149
Louisville Gas & Electric Co	Trimble Station (LGE)	6	110.05	123.54	Gas	NG	GT	GT	141.29
Appalachian Power Co	Phil Sporn	5	121.44	124.2	Coal	BIT	ST	ST	136.758
Louisville Gas & Electric Co	Trimble Station (LGE)	5	110.05	123.54	Gas	NG	GT	GT	134.9
Kentucky Utilities Co	E W Brown	10	106	140	Gas	NG	GT	GT	126
Kentucky Utilities Co	E W Brown	11	106	140	Gas	NG	GT	GT	126
Kentucky Utilities Co	E W Brown	8	106	140	Gas	NG	GT	GT	126
Kentucky Utilities Co	E W Brown	9	106	140	Gas	NG	GT	GT	126
Duke Energy Ohio	Walter C Beckjord	3	128	128	Coal	BIT	ST	ST	125
Duke Energy Ohio	Walter C Beckjord	1	94	94	Coal	BIT	ST	ST	115
Kentucky Utilities Co	E W Brown	1	101	102	Coal	BIT	ST	ST	113.6
Duke Energy Ohio	Walter C Beckjord	2	94	94	Coal	BIT	ST	ST	112.5
Appalachian Power Co	Phil Sporn	1	104.98	108.6	Coal	BIT	ST	ST	110.41
Appalachian Power Co	Phil Sporn	2	104.98	108.6	Coal	BIT	ST	ST	110.41
Appalachian Power Co	Phil Sporn	3	104.98	108.6	Coal	BIT	ST	ST	110.41
Appalachian Power Co	Phil Sporn	4	104.98	108.6	Coal	BIT	ST	ST	110.41
Louisville Gas & Electric Co	Trimble Station (LGE)	GT10	95.76	109.62	Gas	NG	GT	GT	109.62
Louisville Gas & Electric Co	Trimble Station (LGE)	GT9	95.76	109.62	Gas	NG	GT	GT	109.62
Kentucky Utilities Co	E W Brown	6	101.68	112.22	Gas	NG	GT	GT	109.616
Kentucky Utilities Co	E W Brown	7	101.68	112.22	Gas	NG	GT	GT	109.616
East Kentucky Power Coop	JK Smith	4	74	98	Gas	NG	GT	GT	108
East Kentucky Power Coop	JK Smith	5	74	98	Gas	NG	GT	GT	108
Louisville Gas & Electric Co	Trimble Station (LGE)	7	98.28	107.1	Gas	NG	GT	GT	107.1
Louisville Gas & Electric Co	Trimble Station (LGE)	8	98.28	107.1	Gas	NG	GT	GT	107.1

Source: Global Energy Decisions

Plant Operator Name	Plant Name	Unit	Summer Capacity MW	Winter Capacity MW	Primary Fuel Category	Primary Fuel Code	Prime Mover Category	Prime Mover Code	Nameplate Capacity MW
Dayton Power & Light Co (The)	Frank M Tait	GT2	89	102	Gas	NG	GT	GT	106.1
Dayton Power & Light Co (The)	Frank M Tait	GT1	87	100	Gas	NG	GT	GT	103.5
Duke Energy Ohio	Dicks Creek	1	92	110	Gas	NG	GT	GT	100
Duke Energy Ohio	Miami Fort	5	80	80	Coal	BIT	ST	ST	100
East Kentucky Power Coop	J Sherman Cooper	1	116	116	Coal	BIT	ST	ST	100
Dayton Power & Light Co (The)	Frank M Tait	GT3	80	102	Gas	NG	GT	GT	99

Source: Global Energy Decisions

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2006-00463
INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007
REQUEST NO. 6
RESPONDING PERSON: DARRIN ADAMS

Request 6: Provide one-line breaker diagrams of 138 kV and 345 kV substations that border the EKPC system at J. K. Smith Generating Station.

Response: This document is the subject of the Applicant's Petition for Confidential Treatment and is included as **Data Response 6 Exhibit A** in that Petition filed this date. However, the one-line diagrams provided in response to Request #4 Exhibit A, B, and C contain the requested information. The EKPC system one-line diagram, which shows all EKPC substations, including those adjacent to the J. K. Smith Generating Station, is included with the Petition for Confidential Treatment as Request 6 Exhibit A, as well as Request 6 Exhibit B and C which contain a one-line diagram showing the new 345 kV and 138 kV configurations at the J. K. Smith Generating Substation.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2006-00463

INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007

REQUEST NO. 7

RESPONDING PERSON: DARRIN ADAMS

Request 7: Provide EKPC's current thermal, voltage, stability, and short circuit design criterion.

Response:

Section 1
Overview and General Discussion

The primary purpose of East Kentucky Power Cooperative's (EKPC's) transmission system is to reliably transmit electrical energy from its available generating resources to customers served by its transmission system. Interconnections have been constructed in the past with other utilities, to increase the reliability of the EKPC transmission system, and to provide EKPC customers access to other economic and/or emergency generating resources.

EKPC subscribes to and designs its transmission to conform to the fundamental characteristics of a reliable interconnected bulk electric system recommended by the North American Electric Reliability Council (NERC). Additionally, EKPC is a member of the SERC Reliability Corporation (SERC) and subscribes to and designs its transmission system to comply with the reliability principles and responsibilities set forth by SERC.

The Federal Energy Regulatory Commission (FERC) requires all public utilities that own, operate, or control facilities used for transmitting electric energy in interstate commerce to have on file open access non-discriminatory transmission tariffs. EKPC has these tariffs on file to provide firm and non-firm point-to-point transmission service for other entities, as well as firm network service.

The American National Standards Institute (ANSI), The Institute of Electrical and Electronic Engineers, Inc (IEEE), and The Rural Utilities Services (RUS) all publish standards for power system equipment design and application. EKPC incorporates these standards in the design and application of equipment utilized on its transmission system.

The NERC and SERC standards and requirements previously referred to above are discussed in Section 2. The EKPC Planning Criteria is presented in Section 3.

Section 2

NERC and SERC Reliability Standards

NERC in its Reliability Standards states the fundamental requirements for planning reliable interconnected bulk electric systems and the required actions or system performance necessary to comply. The Regions, Subregions, Power Pools, and their members have the responsibility to develop their own appropriate planning criteria and/or guides that are based on the NERC Reliability Standards.

EKPC is a member of SERC. SERC has developed a Supplement, entitled "SERC Supplement – Transmission System Performance (NERC Reliability Standards

TPL-001 through 004). This SERC Supplement contains the standards that transmission providers are expected to adhere to in their simulated testing and system performance evaluations. EKPC has developed and adopted planning criteria and guides that meet or exceed the requirements in this SERC Supplement.

Section 3

EKPC Transmission System Planning Criteria

3.1 Overview

In general, EKPC's transmission system is planned to withstand forced outages of generators and transmission facilities, individually and combined. Table 1 describes the contingencies and measurements EKPC utilizes in testing and assessing the performance of its transmission system

For all testing conditions, stability of the network should be maintained, and cascading outages should not occur. Specific modeling considerations are considered as part of the testing conditions, which are discussed in Section 3.1.

Table 1: Transmission Planning Contingencies and Measurements

Contingencies[1]	Max. Facility Ratings	Min. Volt Level (P.U.)[2]	Max. Volt Level[3] (P.U.)	Curtail Demand and/or Transfers
None(Base Case)	Tables 2,3	0.955	1.050	no
Extreme load due to unusual weather.[4]	Tables 2,3	0.940	1.050	no
Outage of a generator, transmission circuit, or transformer.[5]	Tables 2,3	0.925	1.050	no
Outage of two(2) generators.	Tables 2.3	0.925	1.050	no
Outage of a generator and a transmission circuit or transformer.	Tables 2,3	0.925	1.050	no
Outage of a bus section or a circuit breaker.[6]	Tables 2,3	0.925	1.050	yes
Outage of two(2) transmission circuits.	Tables 2,3	0.925	1.050	yes
Outage of a transmission circuit and a transformer.	Tables 2,3	0.925	1.050	yes
Outage of two(2) transformers.	Tables 2,3	0.925	1.050	yes
Outage of a double circuit tower line.[7]	Tables 2,3	0.925	1.050	yes
Outage of a generator, transmission circuit, transformer, or bus section.[8]	Tables 2,3	0.925	1.050	yes

1 All contingencies(except as noted) are single line to ground or 3-phase faults with normal clearing. For all testing conditions, network stability should be maintained and cascading should not occur.

2 Measured at the unregulated low side distribution transformer bus.

3 For peak load conditions. Maximum off-peak voltage level at unregulated low side distribution transformer bus = 1.085 P.U.

4 Based on a 10% probability load forecast. Fault conditions do not apply.

5 Includes outages which do not result from a fault.

6 Single line to ground with normal clearing.

7 Non 3-phase, with normal clearing.

8 Single line to ground, with delayed clearing.

Table 2: EKPC Typical Line Ratings[9]
(Maximum Conductor Operating Temperatures)

Line Type	Thermal Capability(MVA) Normal / Contingency[10] 176 / 212°F Operation Winter	Summer
69 kV 1/0 ACSR6x1	37 / 40	27 / 32
69 kV 2/0 ACSR 6x1	43 / 46	31 / 37
69 kV 3/0 ACSR 6x1	54 / 59	39 / 47
69 kV 195.7 ACAR	58 / 64	42 / 51
69 kV 4/0 ACSR 6x1	62 / 68	45 / 55
69 kV 266.8 ACSR 26x7	78 / 87	57 / 69
69 kV 556.5 ACSR TW 26x7	121 / 135	88 / 108
69 kV 556.5 ACSR 26x7	125 / 139	90 / 111
69 kV 795 ACSR 26x7	157 / 175	113 / 140
138 kV 556.5 ACSR TW 26x7	242 / 270	176 / 216
138 kV 556.5 ACSR 26x7	250 / 278	181 / 222
138 kV 636 ACSR 26x7	273 / 303	197 / 242
138 kV 795 ACSR 26x7	315 / 351	227 / 280
138 kV 954 ACSR 54x7	349 / 389	251 / 311
161 kV 636 ACSR 26x7	318 / 354	230 / 283
161 kV 795 ACSR 26x7	367 / 409	265 / 327
161 kV 954 ACSR 54x7	407 / 454	293 / 363
345 kV 2-954 ACSR 54x7	1746 / 1947	1257 / 1554

[9] Line rating may be limited by terminal facilities or by maximum existing conductor operating temperature.

[10] Normal ratings apply only to base case conditions. Contingency ratings apply to contingency conditions.

Table 3: EKPC Transformer Ratings(Maximum)[11]

	Rated kV			MVA Rating[12]			
	High Side	Low Side	Rated MVA	Summer(95F) Norm	Summer(95F) Emer	Winter(32F) Norm	Winter(32F) Emer
55C Rise							
OA	161	138	75	71	107	100	135
	161, 138	69	75	71	107	100	135
	161	69	60	57	86	80	108
	161, 138	69	50	47	71	67	90
	138	69	49.5	47	71	66	89
	138	69	45	43	64	60	81
	161	69	35	33	50	47	63
	161	69	26.8	25	38	36	48
	138	69	25.5	24	36	34	46
OA/FA/FA OA/FOA/FOA	138	69	82.5	78	111	107	136
65C Rise							
OA	345	138	270	257	367	340	475
	345	138	180	171	245	227	317
	161	138	90	86	122	113	158
	161, 138	69	90	86	122	113	158
	161, 138	69	60	57	82	76	106
OA/FA/FA	345	138	450	434	581	536	662
OA/FOA/FOA	345	138	300	290	387	357	441
	161	138	150	145	194	179	221
	161, 138	69	150	145	194	179	221
	161	138	140	135	181	167	206
	161, 138	69	140	135	181	167	206
	161, 138	69	100	97	129	119	147
	161, 138	69	93.3	90	120	111	137
	138	69	84	81	108	100	123
	161, 138	69	65.4	63	84	78	96
	138	69	65.3	63	84	77	96
	161	69	50	48	65	60	74
	138	69	47.6	46	61	57	70

[11] Transformer rating may be limited by terminal facilities.

[12] Normal ratings apply only to base case conditions. Contingency ratings apply to contingency conditions.

3.1 Plant Voltage Schedules

For major power plants, the voltage level at the high side of the generator step up transformer(GSU) should be maintainable with normal generation and normal transmission system conditions as follows:

Plant Name	GSU High Side Bus Name and (kV)	Scheduled Voltage (kV)	Scheduled Voltage (Per Unit)
H. L. Spurlock	Spurlock 345	355	1.029
H. L. Spurlock	Spurlock 138	142	1.029
J. S. Cooper	Cooper 161	166	1.031
W. C. Dale	Dale 138	142	1.029
W. C. Dale	Dale 69	72	1.043
J. K. Smith	J. K. Smith 138	142	1.029

3.2 Modeling Considerations

Replacement generation required to offset generating unit outages should be simulated first from all available internal resources. If internal resources are not available or are exhausted, then replacement generation should be simulated from the most restrictive of interconnected companies (AEP, CINergy, LGEE, or TVA).

A single outage may include multiple transmission components in the common zone of relay protection.

Post-fault conditions and conditions after load restoration should be evaluated. Post-contingency operator initiated actions to restore load service must be simulated. Load that is off-line as a result of the contingency being evaluated may be switched to alternate sources during the restoration process, however, load should not be taken off-line to perform switching.

Transmission capacitor status (on/off) should be simulated consistent with existing automatic voltage control (on/off) settings and operating practice during normal transmission system conditions. Manual on-line switching of capacitors during normal conditions can be simulated provided it is consistent with existing operational practice, however, manual switching should not be simulated following a contingency to eliminate low voltage conditions.

The following operational procedures should be avoided:

1) Seasonal adjustment(s) of fixed taps on transmission transformers to control voltage(s) within acceptable ranges.
2) Switching HV and EHV system facilities out of service to reduce off-peak voltage(s).

3.3 Reliability Criteria

Customer Interruptions - Customer interruptions may occur due to an outage of a subtransmission circuit or a distribution substation transformer. To minimize the time and number of customers affected by a single contingency outage, the following criteria should be applied:

(a) Spare Distribution Transformer - To provide for the failure of the distribution substation transformer, a spare transformer should be maintained and available for installation at the affected substation within 10 hours.

(b) Distribution Substation Supply - Transmission radial supply to a distribution substation is acceptable provided that the tap "load-exposure" index, TE, does not exceed 100 MW-miles. When this index is exceeded, multiple source supply should be provided to reduce this index below 100 MW-miles.

(c) Subtransmission Circuit - The circuit "load-exposure" index, CE, should not exceed 2400 MW-miles.

3.4 Load Level

Future transmission facility requirements should be determined using power flow base cases which model coincident individual substation peak demands(summer and winter) forecasted on a normal weather basis. Future transmission facility requirements should also be determined using summer and winter load flow base cases simulating a 10% probability severe weather load forecast. A severe weather load flow case will be considered in itself as an abnormal system planning condition.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2006-00463
INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007
REQUEST NO. 8
RESPONDING PERSON: DARRIN ADAMS

Request 8: Provide the current SERC thermal, voltage, stability, and short circuit design criterion.

Response: See **Data Request #8 Exhibit A** filed herein.

SERC Supplement

Transmission System Performance

NERC Reliability Standards TPL-001 through 004

RESPONSE TO STAFF'S DATA REQUEST 8 EXHIBIT A

Revision History

Revision	Date	Comments
0	January 30, 2002	Initial approval of supplement
1	April 26, 2002	Updated Attachment 3: Planning Standard I.A.S3.M3 Compliance Template to show NERC Board approval date of February 20, 2002
2	March 14, 2003	Applicability statement added; Corrective Plan definition added; reporting timeframe guidance added
3	March 12, 2004	Minor wording changes
4	June 9, 2004	Update to reflect April 2, 2004 NERC Standards & Compliance Templates
5	March 11, 2005	Update to reflect new Version 0 NERC Reliability Standards
6	October 13, 2005	Addition of definition for Radial Transmission Line and clarification of applicability

Responsible SERC Subgroup & Region Review Group

The Reliability Review Subcommittee (RRS) is the Region Review Group and the Responsible SERC Subgroup for the NERC Reliability Standards TPL 001 through 004.

Review and Re-Certification Requirements

This procedure will be reviewed annually or as appropriate by the RRS for possible revision. The existing or revised document will be re-certified at least every 3 years and distributed to all members by the SERC Engineering Committee.

Table of Contents

List of Attachments

I. Introduction/Purpose

Background

The NERC I.A Planning Standards on Transmission Systems were approved by the NERC Board of Trustees in September 1997. The I.A Planning Standards and their related Compliance Templates have gone through subsequent reviews and revisions in accordance with the Board approved 1997 NERC Standards Development Process. The I.A.S1.M1 and I.A.S2.M2 Standards/Measures, which were introduced in Phase I (1999) of the NERC Compliance Program, have been revised as of December 15, 2000, and were approved by the NERC Board of Trustees in June 2001. The I.A.S3.M3 and I.A.S4.M4 Standards/Measures were introduced in Phase II (2000) of the NERC Compliance Program. Measurement 4 was approved by the NERC Board of Trustees in November 2001. Measurement 3 was approved by the NERC Board of Trustees in February 2002. All I.A Planning Standards were revised and approved by the NERC Board of Trustees on April 2, 2004. This revision incorporates the changes resulting from the NERC Reliability Standards Version 0 into the SERC Supplement

The SERC Engineering Committee's (EC) Reliability Review Subcommittee (RRS) serves as the SERC Region Review Group (RRG) for the NERC Reliability Standards TPL-001 through 004 on Transmission Systems. The RRS develops standardized member reporting forms, reviews SERC member submittals for the NERC Standards TPL-001 through 004 , and prepares Compliance Reports which are submitted to the SERC EC's Compliance Review Steering Committee (CRSC).

Purpose

The RRS prepared this supplement to outline SERC's interpretation and to clarify SERC's expectations of members with regard to the NERC Reliability Standards TPL-001 through 004. The RRS developed this supplement after discerning differences in member interpretations during annual compliance review activities.

SERC believes that interpreting NERC Reliability TPL-001 through 004 Standards as purely prescriptive is inappropriate. The Standards are not intended to replace good engineering judgment and the knowledge of a skilled workforce experienced with the system under study. The Standards do, however, provide a useful framework by which members may plan the interconnected transmission system.

Since these Standards are referenced by other NERC Reliability Standards with different RRGs, the following SERC EC Subgroups have also been asked to review this document and provide input:

Compliance Review Steering Committee (CRSC)

Planning Standards Subcommittee (PSS)
Protection & Control Subcommittee (PCS)
Dynamics Review Subcommittee (DRS)

This document should be reviewed by these groups on an annual basis, in conjunction with the SERC Compliance Program, and revised as necessary to reflect ongoing efforts to clarify member expectations and SERC's interpretation of NERC Reliability Standards TPL-001 through 004.

All or portions of the compliance information submitted by SERC Members as part of the NERC Reliability Standards may be regarded as highly sensitive or confidential. Such information shall be maintained, distributed, and communicated in a manner consistent with the SERC Policy Regarding the Confidentiality of Data Submitted by SERC Members.

II. Definitions

Valid Assessment - Valid assessments shall be supported by a current or past simulation/study that addresses the plan year being assessed; address any planned upgrades needed to meet the performance requirements; and be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons, as applicable. Where planned upgrades must be addressed, this will involve submittal of a Corrective Plan as described in the compliance templates.

Simulations – Actual studies that demonstrate the steady-state and dynamic performance of the transmission system. Current year or past year simulations are the basis for valid assessments (see Sections III.D.1 & III.D.2 of this supplement for clarification on the use of past year simulations).

Corrective Plan – As described in the compliance templates, a Corrective Plan is a summary of plans necessary to achieve the required system performance throughout the planning horizon. Corrective Plans should include content such as:

- Project name
- Project description
- In-service date
- Projects for the near-term planning horizon
- Projects for the longer-term planning horizon
- Projects for thermal, voltage, and stability concerns

Radial Transmission Line - Transmission line serving load with only one transmission source. Lines connecting generators at voltages 100 kV and above are not radial.

III. Requirements/Expectations

A. Standard Applicability

The NERC Reliability TPL-001 through 004 Standards are applicable to Planning Authorities (PA)s and Transmission Planners (TP)s. PAs and TPs whose systems consist entirely of Radial Transmission Lines or lower voltage (less than 100 kV) transmission lines are excepted.

B. System Modeling Data

In order to conduct simulations of the planned interconnected transmission system's performance, modeling data for projected system conditions must be developed and periodically updated. Modeling data is covered under NERC Reliability Standards MOD-010 through MOD-021 (System Modeling Data Requirements), and is a fundamental foundation for the performance of meaningful system simulations and assessments. This data should also conform to the system equipment rating methodologies in NERC Reliability Standard FAC-004 and FAC-005. PAs and TPs within SERC are expected to participate in an annual process of updating Regional power flow and dynamic stability model data for a prescribed set of projected system conditions. This participation may be through a designated agent with appropriate notification to SERC if a designated agent is utilized.

The VACAR-Southern-TVA-Entergy (VST-E) participants currently update the SERC Region's steady-state power flow modeling data annually. The series of steady-state model data updated annually is determined by the VST-E Steering Committee, and, at a minimum, conforms to the planned NERC Multi-regional Modeling Working Group (MMWG) base case model series.

The VST-E Stability Study Group (SSG) currently updates the SERC Region's dynamics modeling data annually. The series of dynamics model data updated annually is determined by the SSG, and, at a minimum, conforms to the planned NERC MMWG dynamics series of cases.

SERC recognizes that the modeling data provided by member entities in support of Regional modeling efforts may represent a reduced representation of the member's internal planning model. However, it is SERC's expectation that the model data submitted for Regional models will be of sufficient detail to facilitate simulations of the interconnected transmission system performance at prescribed demand levels.

C. Transmission Reliability Assessments

PAs and TPs within SERC are expected to perform transmission reliability assessments on an annual basis in order to maintain compliance with the NERC Reliability Standards TPL-001 through 004. These assessments shall be based on the results of system simulation studies and engineering judgment. The annual assessments shall be documented by the responsible entities and are subject to audit by SERC. For compliance-related activities, members should base assumptions and filings on the most recent annual assessment, regardless of the calendar year the assessment was performed. For audit purposes, members should retain reliability assessments for a sufficient amount of time to demonstrate appropriate planning processes. At a minimum, the assessments are required to address the following topics:

Near-term Planning Horizon Assessment (years one through five)

- The projected system conditions for the near-term planning horizon assessment (year(s), season(s), demand levels (peak to minimum), interchange, firm transmission services).
- A summary of thermal loading concerns in the near-term planning horizon and approved / proposed corrective plans.
- A summary of voltage profile concerns in the near-term planning horizon and approved / proposed corrective plans.
- A summary of dynamic stability concerns in the near-term planning horizon and approved / proposed corrective plans.
- Interim measures developed for the short-term, prior to implementation of corrective plans.

Longer-term Planning Horizon Assessment (years six through ten)

- The system conditions for the longer-term planning horizon assessment (year(s), season(s), demand levels (peak to minimum), interchange, firm transmission services)
- A summary of thermal loading concerns for the longer-term planning horizon and conceptual / proposed / approved corrective plans.
- A summary of voltage profile concerns for the longer-term planning horizon and conceptual / proposed / approved corrective plans.
- As available, a summary of dynamic stability concerns for the longer-term planning horizon and conceptual / proposed / approved corrective plans.

SERC recognizes the difficulties in longer-term dynamic modeling and stability studies due, in large part, to the uncertainties surrounding the addition of merchant generation, their frequency of operation and identification of their load sink. In addition, these longer-term studies are substantially dependent on NERC MMWG stability cases, which are not currently available for this timeframe. Therefore, SERC does not require stability simulations for the longer-term planning horizon for full compliance. However, each PA and TP is responsible for performing stability studies on new generation as soon as the data is available and prior to interconnection. All stability problems should be addressed before interconnected operation is allowed.

General

- The time frame that the actual system simulations were performed (current year / previous year(s)) which were utilized for the near-term and longer-term planning horizon assessments.
- Justification for using previous year(s) simulations for current year assessments.
- The rationale for the Category B, C, and D contingency selections used for the system simulation studies.
- A discussion of deviations between the planning horizon assumptions and operating experience that might impact the accuracy of the assessment.
- A listing of major interconnected transmission system changes / improvements that have occurred since the previous assessment, and the associated effective date.
- A discussion on the adequacy of the simulations performed, especially if no problems are reported for a category.

SERC recognizes that PA and TP entities must prioritize corrective action plans for identified system deficiencies. To that end, the in-service dates of corrective actions may from time to time be shifted to accommodate higher priority concerns. It is therefore appropriate that the annual transmission assessments discuss any adjustments to corrective action plans, the expected reliability impact, and priority ranking methodologies.

D. System Simulations

PAs and TPs are expected to conduct system simulation studies on an annual basis. However, annual transmission reliability assessments may utilize select simulation studies performed in previous years if the results are still considered valid by the responsible entity. SERC does not interpret the TPL-001 through 004 Standards as an exercise in overburdening members' engineering resources with simulation studies. It is SERC's expectation that the responsible entities will commit the necessary engineering resources to ensure adequate planning for the reliability of the interconnected transmission system. Advancements in computing technology and speed facilitate the screening of a large number of credible contingency scenarios.

SERC recognizes the distinction between steady state and dynamic simulation studies. The model data, software tools, and engineering experience required for these types of simulation studies differ, as do the necessary skill sets and time requirements.

Steady-state Simulations

Models of the transmission system are developed and maintained using conventional steady-state analysis software tools (e.g., PSS/E). These models generally represent a snapshot of the transmission system at a specific point in time (e.g., a peak). Models can be developed for any number of scenarios, but some generally accepted scenarios include a summer peak, a winter peak, and light-load models (usually spring/fall, to capture possible high-voltage conditions, pumped-storage loads or other special light-load scenarios). These models are developed by incorporating current and projected system upgrades. Projected system upgrades must be of high confidence before they are incorporated into the planning models. Generation dispatch will differ depending on the scenarios being studied.

In all cases of steady state simulations, the intent is to demonstrate compliance with the thermal and voltage criteria of Table I. Demonstration of compliance with the stability criterion is accomplished through dynamic simulation, and is covered in a separate topic, below. Simulations for all Table I categories should be performed every year in order to achieve a valid assessment for compliance with the NERC Reliability Standards (TPL-001 through 004) unless changes to system conditions do not warrant such analyses, in which case the annual assessment can be based on simulation studies conducted in previous years. However, as a general guideline, simulations should not be more than five years old. Furthermore, it is also required that the simulation specifically cover the year being assessed. Thus a study performed in 2002 will only be valid for an assessment of 2005 compliance if the 2002 simulation specifically accounted for system conditions in 2005.

Dynamic Simulations

An assessment of system stability must be performed with a dynamic simulation. These models are created independently of the steady-state models, and different software analysis tools are utilized for the dynamic simulation testing. As in the steady-state simulation section, dynamic simulations to demonstrate compliance with Table I categories should be performed as changes to the system warrant. However, as a general guideline, simulations should not be more than five years old. Furthermore, it is also required that the simulation specifically cover the year being assessed. Thus a study performed in 2002 will only be valid for an assessment of 2005 compliance if the 2002 simulation specifically accounted for system conditions in 2005.

In all cases, engineering judgment within the bounds of good utility practice must be liberally applied in determining whether or not system conditions warrant an update to the simulations. Some examples of conditions (but certainly not an inclusive list) would be the addition of new generation in the area, the construction of new transmission lines in the area, the introduction of a Special Protection System to the system, etc. Individual members must evaluate the need for an update to their simulations in order to ensure they are fully compliant with the requirements outlined in Table I of NERC Reliability Standards TPL-001 through 004.

Attachment 1
NERC Reliability Standard
Standard TPL-001-0 — System Performance Under Normal Conditions

A. Introduction

1. **Title:** **System Performance Under Normal (No Contingency) Conditions (Category A)**

2. **Number:** TPL-001-0

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Proposed Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0_R3_1 and TPL-001-0_R3-2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe
Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. **Levels of Non-Compliance**

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. **None identified.**

Version History

Version	Date	Action	Change Tracking

Attachment 2
NERC Reliability Standard
Standard TPL-002-0 — System Performance Following Loss of a Single BES Element

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**
2. **Number:** TPL-002-0
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
   - **4.1.** Planning Authority
   - **4.2.** Transmission Planner
5. **Proposed Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories,, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Monitoring Responsibility**
   Compliance Monitor: Regional Reliability Organizations.
   Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

   1.2. **Compliance Monitoring Period and Reset Timeframe**
   Annually.

   1.3. **Data Retention**
   None specified.

   1.4. **Additional Compliance Information**
   None.

2. **Levels of Non-Compliance**

   2.1. **Level 1:** Not applicable.

   2.2. **Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

   2.3. **Level 3:** Not applicable.

   2.4. **Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Attachment 3
NERC Reliability Standard

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-0

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   R3.1. Planning Authority

   R3.2. Transmission Planner

5. **Proposed Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.2. Including a schedule for implementation.

R2.3. Including a discussion of expected required in-service dates of facilities.

R2.4. Consider lead times necessary to implement plans.

R2.5. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Attachment 4
NERC Reliability Standard
Standard TPL-004-0 — System Performance Following Extreme BES Events

A. Introduction

1. **Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)**
2. **Number:** TPL-004-0
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner
5. **Proposed Effective Date: April 1, 2005**

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

M2.1 Be made annually.

M2.2 Be conducted for near-term (years one through five).

M2.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

M2.4 Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M3. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0_R1.

M4. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Attachment 4
NERC Reliability Standard
Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating[a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:			
	1. Generator	Yes	No[b]	No
	2. Transmission Circuit	Yes	No[b]	No
	3. Transformer	Yes	No[b]	No
	Loss of an Element without a Fault.	Yes	No[b]	No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section	Yes	Planned/ Controlled[c]	No
	2. Breaker (failure or internal Fault)	Yes	Planned/ Controlled[c]	No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]:	Yes	Planned/ Controlled[c]	No
	5. Any two circuits of a multiple circuit towerline[f]	Yes	Planned/ Controlled[c]	No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator	Yes	Planned/ Controlled[c]	No
	7. Transformer	Yes	Planned/ Controlled[c]	No
	8. Transmission Circuit	Yes	Planned/ Controlled[c]	No
	9. Bus Section	Yes	Planned/ Controlled[c]	No

Attachment 4
NERC Reliability Standard
Table I. Transmission System Standards – Normal and Emergency Conditions

D[d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2006-00463
INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007
REQUEST NO. 9
RESPONDING PERSON: JULIA J. TUCKER

Request 9: Provide EKPC's summer and winter coincident peak load forecast projections for an approximate 10-year period for the EKPC system, in total and by appropriate sub-areas.

Response: A redacted version of the peak load forecast projection for the 10-year period is attached as **Data Response 9 Exhibit A.** The remainder of this document is the subject of the Applicant's Petition for Confidential Treatment and is included in that Petition filed this date.

DATA RESPONSE 9
EXHIBIT A

EXHIBIT 9 - CONFIDENTAIL
REDACTED VERSION

Date	Jackson	Salt River	Taylor County	Inter-County	Shelby	Farmers	Owen	Clark	Nolin	Fleming-Mason	South Kentucky	Licking Valley	Cumberland Valley	Big Sandy	Grayson	Blue Grass	Total EKPC
Jan-08	[redacted]																2848
Jan-09	[redacted]																2938
Jan-10	[redacted]																3021
Jan-11	[redacted]																3094
Jan-12	[redacted]																3162
Jan-13	[redacted]																3251
Jan-14	[redacted]																3326
Jan-15	[redacted]																3398
Jan-16	[redacted]																3468
Jan-17	[redacted]																3560

Date	Jackson	Salt River	Taylor County	Inter-County	Shelby	Farmers	Owen	Clark	Nolin	Fleming-Mason	South Kentucky	Licking Valley	Cumberland Valley	Big Sandy	Grayson	Blue Grass	Total EKPC
Jul-07	[redacted]																2213
Jul-08	[redacted]																2273
Jul-09	[redacted]																2342
Jul-10	[redacted]																2403
Jul-11	[redacted]																2457
Jul-12	[redacted]																2506
Jul-13	[redacted]																2569
Jul-14	[redacted]																2621
Jul-15	[redacted]																2674
Jul-16	[redacted]																2725

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2006-00463

INFORMATION REQUEST RESPONSE

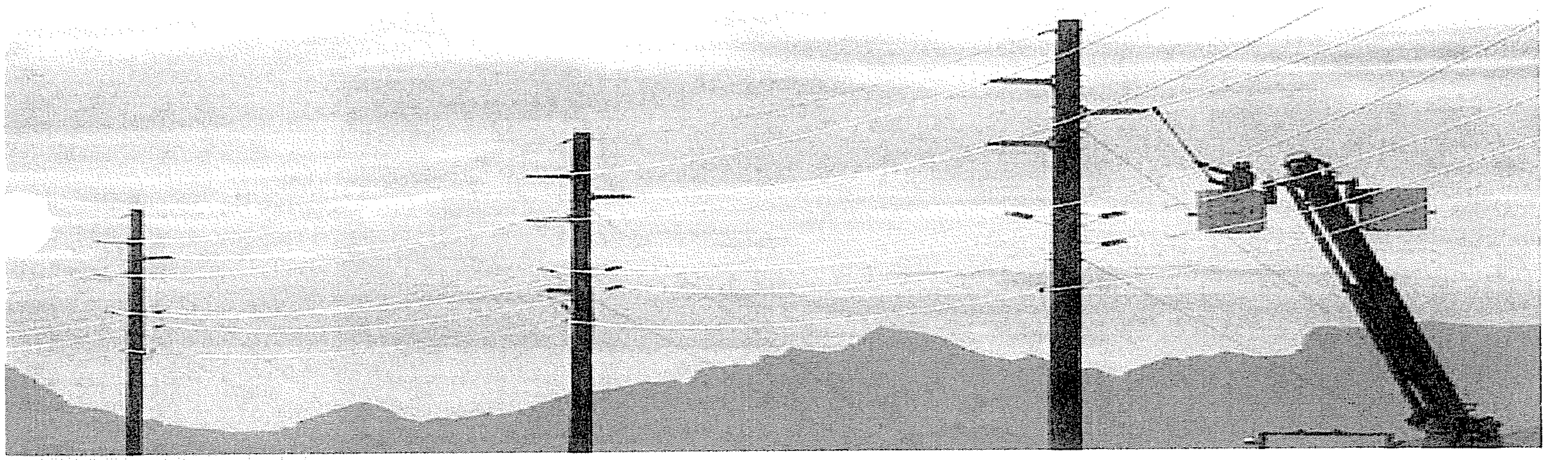
PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007

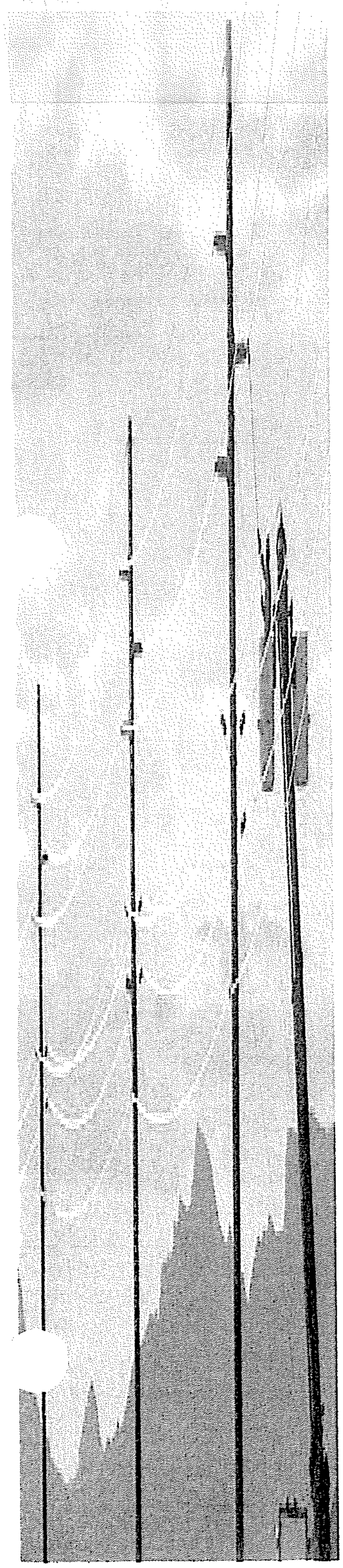
REQUEST NO. 10

RESPONDING PERSON: JULIA J. TUCKER

Request 10: Describe in detail EKPC load forecasting methodology, including inputs and weather normalization.

Response: See **Data Request #10 Exhibit A** filed herein





RESPONSE TO STAFF'S
DATA REQUEST 10

2006
Load Forecast
Report

Prepared by:

East Kentucky Power Cooperative

Forecasting and Market Analysis Department

August 2006

TABLE OF CONTENTS

SEPARATE APPENDICES

APPENDIX	**DESCRIPTION**
A	**Member System Load Forecast Reports**
B	**Regional Model Results** **Sales and Customer Forecasts – Definitions, Assumptions, Models Specifications, and Results**

SECTION 1.0

EXECUTIVE SUMMARY

Section 1.0
Executive Summary

East Kentucky Power Cooperative Inc. (EKPC) is a generation and transmission electric cooperative located in Winchester, Kentucky. It serves 16 member distribution cooperatives who serve approximately 495,000 retail customers. Member distribution cooperatives currently served by EKPC are listed below:

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

In April of 2008, Warren RECC will become a member of EKPC. This summary contains a 20-year projection of peak demand and energy requirements for EKPC, representing the summation of the load forecasts for each of its 16 member distribution cooperatives and starting April 1, 2008, Warren RECC.

EKPC's load forecast is prepared every two years in accordance with EKPC's Rural Utilities Service (RUS) approved Work Plan, which details the methodology employed in preparing the projections. EKPC prepares the load forecast by working jointly with member systems to prepare their load forecasts. Member projections are then summed to determine EKPC's forecast for the 20-year period. Member cooperatives use their load forecasts in developing construction work plans, long range work plans, and financial forecasts. EKPC uses the load forecast in such areas as marketing analyses, transmission planning, power supply planning, and financial forecasting.

Historical and projected total energy requirements, seasonal peak demands, and annual load factor for the EKPC system are presented in Table 1-3 (page 7). Internal demand refers to EKPC's peak demand unadjusted for interruptible loads, and net demand refers to EKPC's peak demand, taking all adjustments into account. Both are based on coincident hourly-integrated demand intervals. Load Factor is calculated using net peak demand and energy requirements.

EKPC's load forecast indicates that total energy requirements are projected to increase by 3.0 percent per year over the 2006 through 2026 period. Net winter peak demand will increase by approximately 2,400 MW, and net summer peak demand will increase by approximately 1,700 MW. Annual load factor projections are remaining steady at approximately 53 percent.

Energy projections for the residential, small commercial, and large commercial classifications indicate that during the 2006 through 2026 period, sales to the residential class will increase by 2.9 percent per year, and total commercial sales will increase by 3.6 percent per year. Class sales are presented in Tables 1-4. Please note the energy use projection for Gallatin Steel in Table 1-4. EKPC and Owen Electric (Gallatin Steel's electric provider) expect Gallatin Steel to use 1,000,000 MWh per year, adjusted by 360 hours of interruption each year.

Energy and Peak Growth Rates			
	2006-2011	**2006-2016**	**2006-2026**
Total Energy Requirements	5.6%	3.9%	3.0%
Residential Sales	4.7%	3.5%	2.9%
Total Commercial and Industrial Sales (Excluding Gallatin Steel)	8.2%	5.2%	3.6%
Firm Winter Peak Demand	6.3%	4.2%	3.2%
Firm Summer Peak Demand	5.8%	3.9%	3.0%

Factors considered in preparing the forecast include national, regional, and local economic performance, appliance saturations and efficiencies, population and housing trends, service area industrial development, electric price, household income, and weather.

Note: In Tables 1-1 through 1-3, the historical data represents the actual seasonal peaks, including any interruptible loads running at the time of the peak. The forecast assumes these loads will be interrupted. Currently, the interruptible contracts include Gallatin Steel (120 MW interruptible) and other industries (8 MW interruptible).

Table 1-1
Historical and Projected Winter Peak Demand

Season	Total Internal Peak Demand (MW)	Gallatin Steel Interruptible Demand (MW)	Other Interruptible (MW)	Net Peak Demand (MW)
1981 - 82	1,087	0	0	1,087
1982 - 83	845	0	0	845
1983 - 84	1,151	0	0	1,151
1984 - 85	1,125	0	0	1,125
1985 - 86	1,039	0	0	1,039
1986 - 87	983	0	0	983
1987 - 88	1,104	0	0	1,104
1988 - 89	1,114	0	0	1,114
1989 - 90	1,449	0	0	1,449
1990 - 91	1,306	0	0	1,306
1991 - 92	1,383	0	0	1,383
1992 - 93	1,473	0	0	1,473
1993 - 94	1,788	0	0	1,788
1994 - 95	1,621	0	0	1,621
1995 - 96	1,990	75	0	1,915
1996 - 97	2,004	51	0	1,953
1997 - 98	1,789	93	14	1,682
1998 - 99	2,096	108	17	1,971
1999 - 00	2,169	12	17	2,140
2000 - 01	2,322	27	17	2,278
2001 - 02	2,238	129	17	2,092
2002 - 03	2,568	109	24	2,435
2003 - 04	2,610	97	26	2,487
2004 - 05	2,719	97	7	2,615
2005 - 06	2,599	107	15	2,477
2006 - 07	2,901	120	8	2,773
2007 - 08	2,976	120	8	2,848
2008 - 09	3,474	120	8	3,346
2009 - 10	3,567	120	8	3,439
2010 - 11	3,648	120	8	3,520
2011 - 12	3,723	120	8	3,595
2012 - 13	3,822	120	8	3,694
2013 - 14	3,903	120	8	3,775
2014 - 15	3,984	120	8	3,856
2015- 16	4,059	120	8	3,931
2016 - 17	4,159	120	8	4,031
2017 - 18	4,246	120	8	4,118
2018 - 19	4,337	120	8	4,209
2019 - 20	4,427	120	8	4,299
2020 - 21	4,536	120	8	4,408
2021 - 22	4,631	120	8	4,503
2022 - 23	4,725	120	8	4,597
2023 - 24	4,806	120	8	4,678
2024 - 25	4,909	120	8	4,781
2025 - 26	4,997	120	8	4,869

Table 1-2

Historical and Projected Summer Peak Demand

Season	Total Internal Peak Demand (MW)	Gallatin Steel Interruptible Demand (MW)	Other Interruptible (MW)	Net Peak Demand (MW)
1982	694	0	0	694
1983	789	0	0	789
1984	722	0	0	722
1985	776	0	0	776
1986	857	0	0	857
1987	906	0	0	906
1988	1,055	0	0	1,055
1989	1,010	0	0	1,010
1990	1,079	0	0	1,079
1991	1,164	0	0	1,164
1992	1,131	0	0	1,131
1993	1,309	0	0	1,309
1994	1,314	0	0	1,314
1995	1,518	52	0	1,466
1996	1,540	88	0	1,452
1997	1,650	101	0	1,549
1998	1,675	4	17	1,654
1999	1,754	4	12	1,738
2000	1,941	86	23	1,832
2001	1,980	116	23	1,841
2002	2,120	119	23	1,978
2003	1,996	125	26	1,845
2004	2,052	97	7	1,948
2005	2,180	0	10	2,170
2006	2,279	120	8	2,151
2007	2,341	120	8	2,213
2008	2,771	120	8	2,643
2009	2,849	120	8	2,721
2010	2,919	120	8	2,791
2011	2,980	120	8	2,852
2012	3,035	120	8	2,907
2013	3,106	120	8	2,978
2014	3,164	120	8	3,036
2015	3,224	120	8	3,096
2016	3,281	120	8	3,153
2017	3,353	120	8	3,225
2018	3,418	120	8	3,290
2019	3,487	120	8	3,359
2020	3,551	120	8	3,423
2021	3,633	120	8	3,505
2022	3,705	120	8	3,577
2023	3,776	120	8	3,648
2024	3,837	120	8	3,709
2025	3,916	120	8	3,788
2026	3,981	120	8	3,853

Table 1-3
Peak Demands And Total Requirements
~Historical and Projected ~

Season	Net Winter Peak Demand (MW)	Year	Net Summer Peak Demand (MW)	Year	Total Requirements (MWh)	Load Factor (%)
1981 - 82	1,087	1982	694	1982	3,904,954	41%
1982 - 83	845	1983	789	1983	4,099,007	55%
1983 - 84	1,151	1984	722	1984	4,095,268	41%
1984 - 85	1,125	1985	776	1985	4,264,517	43%
1985 - 86	1,039	1986	857	1986	4,470,627	49%
1986 - 87	983	1987	906	1987	4,710,898	55%
1987 - 88	1,104	1988	1,055	1988	5,122,703	53%
1988 - 89	1,114	1989	1,010	1989	5,347,081	55%
1989 - 90	1,449	1990	1,079	1990	5,489,092	43%
1990 - 91	1,306	1991	1,164	1991	5,958,422	52%
1991 - 92	1,383	1992	1,131	1992	6,099,308	50%
1992 - 93	1,473	1993	1,309	1993	6,860,902	53%
1993 - 94	1,788	1994	1,314	1994	6,917,414	44%
1994 - 95	1,621	1995	1,466	1995	7,761,980	55%
1995 - 96	1,915	1996	1,452	1996	8,505,621	51%
1996 - 97	1,953	1997	1,549	1997	8,850,394	52%
1997 - 98	1,682	1998	1,654	1998	9,073,950	61%
1998 - 99	1,971	1999	1,738	1999	9,825,866	57%
1999 - 00	2,140	2000	1,832	2000	10,521,400	56%
2000 - 01	2,278	2001	1,841	2001	10,750,900	54%
2001 - 02	2,092	2002	1,978	2002	11,456,830	62%
2002 - 03	2,435	2003	1,845	2003	11,568,314	54%
2003 - 04	2,489	2004	1,948	2004	11,865,797	54%
2004 - 05	2,615	2005	2,170	2005	12,527,829	55%
2005 - 06	2,477	2006	2,151	2006	12,556,759	58%
2006 - 07	2,773	2007	2,213	2007	12,956,841	53%
2007 - 08	2,848	2008	2,643	2008	14,793,556	59%
2008 - 09	3,346	2009	2,721	2009	15,716,559	54%
2009 - 10	3,439	2010	2,791	2010	16,133,913	53%
2010 - 11	3,520	2011	2,852	2011	16,499,166	54%
2011 - 12	3,595	2012	2,907	2012	16,879,983	54%
2012 - 13	3,694	2013	2,978	2013	17,261,436	53%
2013 - 14	3,775	2014	3,036	2014	17,621,408	53%
2014 - 15	3,856	2015	3,096	2015	17,981,314	53%
2015- 16	3,931	2016	3,153	2016	18,370,418	53%
2016 - 17	4,031	2017	3,225	2017	18,744,186	53%
2017 - 18	4,118	2018	3,290	2018	19,129,686	53%
2018 - 19	4,209	2019	3,359	2019	19,539,698	53%
2019 - 20	4,299	2020	3,423	2020	19,977,370	53%
2020 - 21	4,408	2021	3,505	2021	20,408,388	53%
2021 - 22	4,503	2022	3,577	2022	20,837,354	53%
2022 - 23	4,597	2023	3,648	2023	21,258,006	53%
2023 - 24	4,678	2024	3,709	2024	21,683,180	53%
2024 - 25	4,781	2025	3,788	2025	22,086,886	53%
2025 - 26	4,869	2026	3,853	2026	22,475,651	53%

Table 1-4

Total Member System Retail Energy Sales

Year	Residential Sales (MWh)	Seasonal Sales (MWh)	Small Comm. Sales (MWh)	Public Buildings (MWh)	Large Comm. Sales (MWh)	Gallatin Steel (MWh)	Other Sales (MWh)	Total Retail Sales (MWh)
1990	3,495,899	9,094	813,371	10,770	653,502	0	3,737	4,986,373
1991	3,769,089	9,423	868,031	11,744	725,419	0	4,029	5,387,735
1992	3,811,817	9,756	913,599	13,345	776,268	0	4,304	5,529,089
1993	4,228,581	10,144	980,301	15,684	968,345	0	5,081	6,208,135
1994	4,283,267	10,280	1,014,549	16,073	1,026,927	0	4,156	6,355,251
1995	4,591,084	11,066	1,097,729	17,715	1,119,361	279,070	5,042	7,121,068
1996	4,873,716	12,342	1,138,469	18,732	1,188,760	640,756	5,555	7,878,329
1997	4,899,179	11,888	1,163,683	18,151	1,256,829	755,279	5,663	8,110,671
1998	5,107,125	11,476	1,230,450	19,191	1,345,859	696,051	5,601	8,415,754
1999	5,318,860	11,496	1,336,957	19,763	1,415,128	901,686	5,756	9,009,647
2000	5,624,384	12,479	1,446,958	20,397	1,503,523	917,983	6,160	9,531,884
2001	5,795,728	12,769	1,505,480	21,032	1,666,141	992,711	6,545	10,000,406
2002	6,164,400	14,076	1,577,590	22,776	1,798,352	1,005,493	7,107	10,589,794
2003	6,203,143	13,445	1,550,248	23,975	1,874,044	1,007,676	7,447	10,679,978
2004	6,335,445	13,846	1,598,111	25,266	1,989,780	1,047,466	7,498	11,017,413
2005	6,743,486	14,501	1,733,280	25,065	2,020,930	992,824	7,711	11,537,797
2006	6,702,645	14,445	1,780,456	25,185	2,116,434	981,378	7,945	11,628,489
2007	6,865,831	14,945	1,844,468	25,880	2,257,560	981,718	8,157	11,998,559
2008	7,576,749	15,470	2,143,068	26,578	2,927,518	982,351	12,341	13,684,074
2009	8,036,352	16,009	2,271,045	27,330	3,187,814	981,697	13,773	14,534,020
2010	8,246,901	16,493	2,330,473	28,023	3,301,354	981,659	14,125	14,919,028
2011	8,432,930	16,911	2,387,349	28,674	3,396,327	981,566	14,469	15,258,226
2012	8,650,448	17,466	2,443,562	29,377	3,473,788	981,425	14,817	15,610,882
2013	8,868,278	18,016	2,499,753	30,115	3,550,403	981,156	15,156	15,962,877
2014	9,069,536	18,535	2,555,818	30,813	3,625,976	981,046	15,492	16,297,216
2015	9,270,396	19,050	2,612,249	31,491	3,700,886	981,063	15,824	16,630,959
2016	9,479,347	19,593	2,669,288	32,174	3,792,252	981,254	16,155	16,990,064
2017	9,681,304	20,098	2,727,493	32,868	3,875,814	981,077	16,484	17,335,138
2018	9,900,800	20,637	2,786,650	33,574	3,951,703	980,691	16,815	17,690,869
2019	10,120,469	21,220	2,846,226	34,287	4,052,080	980,619	17,140	18,072,040
2020	10,371,328	21,880	2,905,708	34,941	4,143,897	980,793	17,466	18,476,014
2021	10,624,237	22,524	2,965,803	35,626	4,227,112	980,680	17,788	18,873,770
2022	10,867,695	23,173	3,025,759	36,294	4,317,896	980,577	18,110	19,269,504
2023	11,112,981	23,824	3,085,307	36,890	4,399,917	980,480	18,429	19,657,828
2024	11,371,259	24,512	3,144,693	37,483	4,473,032	980,513	18,745	20,050,237
2025	11,605,707	25,103	3,203,587	38,068	4,553,769	980,287	19,057	20,425,578
2026	11,840,688	25,765	3,262,188	38,649	4,617,527	980,266	19,365	20,784,448

Assumptions: Gallatin will be interrupted 360 hours per year; Warren will become a member April 1, 2008.

Table 1-4 continued

Energy Sales and Total Requirements

Year	Total Retail Sales (MWh)	Office Use (MWh)	% Loss	EKPC Sales to Members (MWh)	EKPC Office Use (MWh)	Transmission Loss (%)	Total Requirements (MWh)
1990	4,986,373	5,087	5.7	5,295,459	6,287	3.4	5,489,092
1991	5,387,735	5,333	6.3	5,755,588	6,798	3.3	5,958,422
1992	5,529,089	5,242	6.2	5,903,267	7,559	3.1	6,099,308
1993	6,208,135	5,552	6.0	6,612,688	8,026	3.5	6,860,902
1994	6,355,251	5,614	5.5	6,727,959	8,541	2.6	6,917,414
1995	7,121,068	5,711	5.5	7,542,687	9,197	2.7	7,761,980
1996	7,878,329	6,167	5.0	8,301,379	8,856	2.3	8,505,621
1997	8,110,671	6,349	5.2	8,559,022	8,505	3.2	8,850,394
1998	8,415,754	6,121	4.5	8,821,630	7,236	2.7	9,073,950
1999	9,009,647	6,040	4.8	9,468,917	8,157	3.5	9,825,866
2000	9,531,884	6,606	5.0	10,039,016	7,862	4.5	10,521,400
2001	10,000,406	6,793	4.0	10,427,269	8,205	2.9	10,750,900
2002	10,589,794	7,562	4.3	11,071,863	8,818	3.3	11,456,830
2003	10,679,978	7,681	4.5	11,190,811	9,123	3.2	11,568,314
2004	11,017,413	8,289	4.5	11,540,687	9,106	2.7	11,865,797
2005	11,537,797	8,629	4.2	12,049,271	8,902	3.7	12,527,829
2006	11,628,489	8,819	4.4	12,170,871	9,185	3.0	12,556,759
2007	11,998,559	8,819	4.4	12,558,905	9,231	3.0	12,956,841
2008	13,684,074	9,489	4.5	14,340,472	9,277	3.0	14,793,556
2009	14,534,020	9,489	4.5	15,235,692	9,370	3.0	15,716,559
2010	14,919,028	9,489	4.6	15,640,431	9,464	3.0	16,133,913
2011	15,258,226	9,489	4.5	15,994,633	9,558	3.0	16,499,166
2012	15,610,882	9,489	4.5	16,363,929	9,654	3.0	16,879,983
2013	15,962,877	9,489	4.6	16,733,842	9,750	3.0	17,261,436
2014	16,297,216	9,489	4.5	17,082,918	9,848	3.0	17,621,408
2015	16,630,959	9,489	4.5	17,431,928	9,946	3.0	17,981,314
2016	16,990,064	9,489	4.5	17,809,259	10,046	3.0	18,370,418
2017	17,335,138	9,489	4.6	18,171,714	10,146	3.0	18,744,186
2018	17,690,869	9,489	4.6	18,545,547	10,248	3.0	19,129,686
2019	18,072,040	9,489	4.5	18,943,156	10,350	3.0	19,539,698
2020	18,476,014	9,489	4.6	19,367,595	10,454	3.0	19,977,370
2021	18,873,770	9,489	4.6	19,785,578	10,558	3.0	20,408,388
2022	19,269,504	9,489	4.6	20,201,569	10,664	3.0	20,837,354
2023	19,657,828	9,489	4.6	20,609,495	10,771	3.0	21,258,006
2024	20,050,237	9,489	4.6	21,021,807	10,878	3.0	21,683,180
2025	20,425,578	9,489	4.6	21,413,292	10,987	3.0	22,086,886
2026	20,784,448	9,489	4.6	21,790,284	11,097	3.0	22,475,651

Assumptions: Gallatin will be interrupted 360 hours per year;
Warren will become a member April 1, 2008.

SECTION 2.0

LOAD FORECAST METHODOLOGY

Section 2.0
Load Forecast Methodology

2.1 Coordination with Member Systems

EKPC prepares a load forecast by working jointly with its member systems in preparing their individual load forecasts. These individual forecasts are included in Appendix A. Member system projections are then summed to determine EKPC's forecast for the 20-year period. Factors considered in preparing the forecasts include national, regional, and local economic performance, appliance saturations and efficiencies, population and housing trends, service area industrial development, electric price, household income, and weather. Each member system reviews the preliminary forecast for reasonability. Final projections reflect analysis of historical data combined with the experience and judgment of the member system manager and staff. In recognition of the uncertainty present in long-term forecasting, both high and low case projections are also prepared (see Section 8).

The general steps followed by EKPC in developing its load forecast are summarized as follows:

1. EKPC prepares a preliminary forecast for each of its member systems which is based on retail sales forecasts for six classes: residential, seasonal, small commercial, public buildings, large commercial, and other. The classifications are taken from the Rural Utilities Services (RUS) Form 7, which contains publicly available retail sales data for member systems. EKPC's sales to member systems are then determined by adding distribution losses to total retail sales. EKPC's total requirements are estimated by adding transmission losses to total sales. Seasonal peak demands are determined by applying peak factors for heating, cooling, and water heating to energy. The same methodology is used in developing each of the 16 member system forecasts.

2. EKPC meets with each member system to discuss their preliminary forecast. Member system staff at these meetings includes the manager and other key individuals.

3. The preliminary forecast is usually revised based on mutual agreement of EKPC staff and member system's Manager and staff. This final forecast is approved by the board of directors of each member system.

4. The EKPC forecast is the summation of the forecasts of its 16 members.

There is close collaboration and coordination between EKPC and its member systems in this process. This working relationship is essential since EKPC has no retail members. Input from member systems relating to such things as industrial development, subdivision growth, and other specific service area information is crucial to the preparation of accurate forecasts. Review meetings provide opportunities to critique the assumptions and the overall results of the preliminary forecast. The resulting load forecast reflects a combination of EKPC's structured forecast methodology tempered by the judgment and experience of the member system staff. Over the years, this forecasting process has resulted in projections accepted by and useful to both EKPC and its members. Member cooperatives use their load forecast in developing two, three and four-year work plans, long-range work plans, and financial forecasts. EKPC uses the load forecast in such areas as marketing analyses, transmission planning, generation planning, and financial forecasting.

2.2 Forecast Model Summary

Models are used to develop the load forecast for each member system. A brief overview of each is given in this section. Specifics regarding the models and resulting forecasts are presented in Sections 4 through 8 of this report.

2.2.1 Regional Economic Model

EKPC has divided its members' service area into six economic regions with economic activity projected for each. Regional forecasts for population, income and employment are developed and used as inputs to residential customer and small commercial customer and energy forecasts. Therefore, EKPC's economic assumptions regarding its load forecast are consistent.

2.2.2 Residential Sales

This class of energy sales is forecasted using regression analysis. Variables include electric price, economic activity, and regional population growth. The number of residential customers is also projected with regression analysis using economic variables such as population. Residential energy use per customer is calculated by dividing the forecasted number of customers into the energy sales forecast.

2.2.3 Small Commercial Sales

Small commercial energy sales forecast results from regression analysis. The number of small commercial customers is forecasted by means of regression analysis on various regional economic data in addition to the resulting residential customer forecast described above. Exogenous variables include real electric price and economic activity. Energy use per customer is calculated as with the residential class.

2.2.4 Large Commercial Sales

This class is projected by member systems and EKPC. Member systems project existing large loads. EKPC projects new large loads based on historical development, the presence of industrial parks, and the economy of the service territory.

2.2.5 Seasonal Sales Forecast

Seasonal sales are sales to customers with seasonal residences such as vacation homes and weekend retreats. Seasonal sales are relatively small and are reported by only one of EKPC's member systems.

2.2.6 Public Building Sales Forecast

Public Building sales include sales to accounts such as government buildings and libraries. The sales are relatively small and are reported by only two of EKPC's member systems.

2.2.7 Other Sales

The 'Other Sales' class represents street lighting. This class is relatively small and is usually projected as a function of residential sales. There are 11 member systems that report this class.

2.2.8 Peak Demand and High and Low Cases

Seasonal peak demands are projected using the summation of monthly energy usages and load factors for the various classes of customers. Residential energy usage components include heating, cooling, water heating, and other usage. Using load factors, demand is calculated for each component and then summed to obtain the residential portion of the seasonal peak. Small commercial and large commercial classes use load factors on the class usage to obtain the class contribution to the seasonal peak. High and low case projections have been constructed around the base case forecast. Weather and customer growth assumptions are two significant inputs to the high and low cases.

SECTION 3.0

LOAD FORECAST DISCUSSION

Section 3.0
Load Forecast Discussion

3.1 Introduction

Key assumptions and trends used in the preparation of the load forecast are described in this section along with a discussion of the EKPC service area. Projected peak demand, annual energy requirements, and growth rates are summarized. Differences between the 2004 and 2006 load forecasts are discussed.

3.2 Input Assumptions

Key forecast assumptions used in developing the EKPC and member system load forecasts are:

1. EKPC's member systems will add approximately 260,000 residential customers by 2026. This represents an increase of 2.3 percent per year. This includes Warren RECC beginning April 2008.

2. EKPC uses an economic model to help develop its load forecast. The model uses data for 89 Kentucky counties in seven geographic regions. The economy of these counties will experience modest growth over the next 20 years. The average unemployment rate will remain relatively flat at 6.8 percent during the 2006 to 2026 timeframe. Total employment levels will rise by 330,000 jobs. Manufacturing employment will decrease from 272,000 jobs in 2004 to 210,000 jobs in 2020. Regional population will grow from 3.5 million people in 2006 to 4.0 million people in 2026, an average growth of 0.7 percent per year.

3. From 2006 through 2026, approximately 70 percent of all new households will have electric heat. Eighty-five percent of all new households will have electric water heating. Nearly all new homes will have electric air conditioning, either central or room.

4. Over the forecast period, naturally occurring appliance efficiency improvements is expected to decrease retail sales nearly 500,000 MWh. Appliances particularly affected are refrigerators, freezers, and air conditioners.

5. Residential customer growth and local area economic activity will be the major determinants of small commercial growth.

6. Forecasted load growth is based on the assumption of normal weather, as defined by the National Oceanic and Atmospheric Administration, occurring over the next 20 years. Seven different stations are used depending on geographic location of the member system.

3.3 Discussion of Service Area

In EKPC's service area, electricity is the primary method for water heating and home heating. Around 85 percent of all homes have electric water heating, and about 54 percent have electric heat. In 2005, 58 percent of EKPC's member retail sales were to the residential class and residential customer use averaged 1,234 kWh per month. While EKPC's load can be considered primarily residential in nature, Figure 3-3 illustrates that commercial/industrial customers make up an increasingly larger share of total retail sales.

The economy of EKPC's service area is quite varied. Areas around Lexington and Louisville have a significant amount of manufacturing industry. The region around Cincinnati contains a growing number of retail trade and service jobs while the eastern and southeastern portions of EKPC's service area are dominated by the mining industry. Tourism is an important aspect of EKPC's southern and southwestern service area, with Lake Cumberland and Mammoth Cave National Park contributing to jobs in the service and retail trade industries. Textile and apparel manufacturing employ a significant number of workers throughout the service area, particularly in the northeastern and southern portions.

3.4 Summary of Results

The forecast indicates that for the period 2006 through 2026, total energy requirements will increase by 3.0 percent per year. Winter and summer net peak demand will increase by 3.2 percent and 3.0 percent, respectively. Annual load factor is projected to remain relatively flat at around 53 percent. Sales to the residential class are projected to increase by 2.9 percent per year, commercial sales are projected to increase by 3.6 percent per year. These growth rates do include Warren RECC as a new member beginning April 2008. Table 3-1 summarizes demand and total requirements. Figure 3-1 summarizes class sales growth rates. Figure 3-2 reports growth rates by class.

The resulting load forecast is for annual energy requirements to increase from 12,527,829 MWh in 2005 to 22,475,651 MWh in 2026. Annual net winter peak demand increases from 2,477 MW to 4,869 MW during the same time period. Table 1-3 on page 7 reports actual and projected total energy requirements, seasonal peak demands, and annual load factor for the years 1990 through 2026. Figures 3-3, 3-4, 3-5 and 3-6 illustrate this information graphically.

Actual and projected requirements by customer class are presented in Table 1-4 on pages 8 and 9, with 5, 10, and 20-year average annual energy growth rates reported in Tables 3-2, 3-3 and 3-4. Forecasted monthly sales for the first two years of the forecast are presented by class in Table 3-5. Table 1-4 reports sales to member systems and total requirements, which includes office use and transmission losses. Figure 3-5 reports the winter peak forecast of EKPC total system and Figure 3-7 shows the growth in the winter peak for each member system.

Table 3-1
Projected Energy and Peak Demand Growth
Compound Annual Rates of Change

				With Warren			Without Warren		
	Historical Growth Rates			2006 Forecast Growth Rates			2006 Forecast Growth Rates		
	2000-2005	1995-2005	1985-2005	2006-2011	2006-2016	2006-2026	2006-2011	2006-2016	2006-2026
Total Energy Requirements	3.6%	6.3%	7.2%	5.6%	3.9%	3.0%	2.8%	2.5%	2.3%
Firm Winter Peak Demand	4.6%	5.3%	4.5%	6.3%	4.2%	3.2%	3.5%	2.9%	2.6%
Firm Summer Peak Demand	2.3%	3.7%	5.3%	5.8%	3.9%	3.0%	2.7%	2.4%	2.3%

Figure 3-1
Average Annual Sales Growth
2006-2026

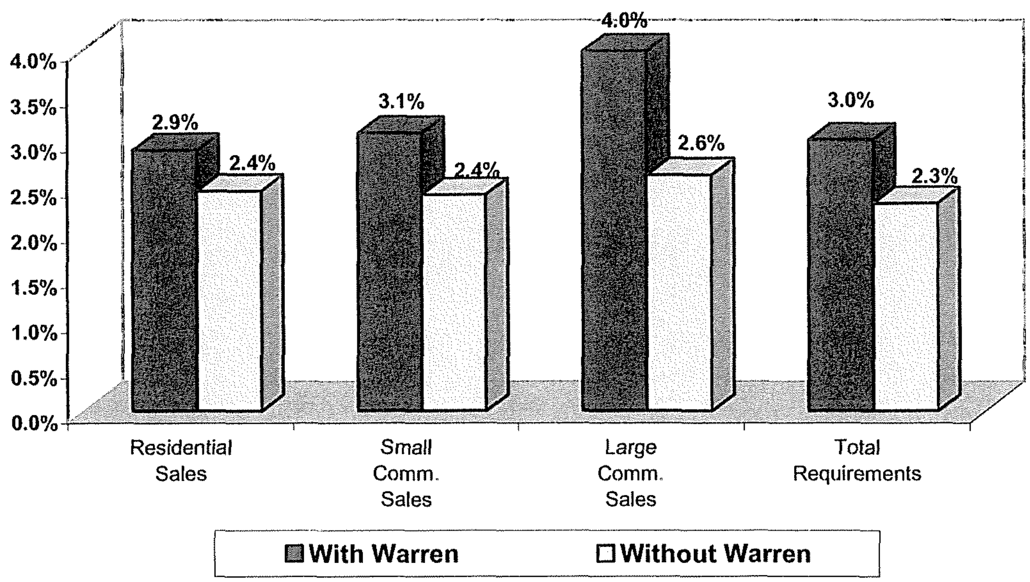


Figure 3-2
Average Annual Growth Sales Including Warren
2006-2026

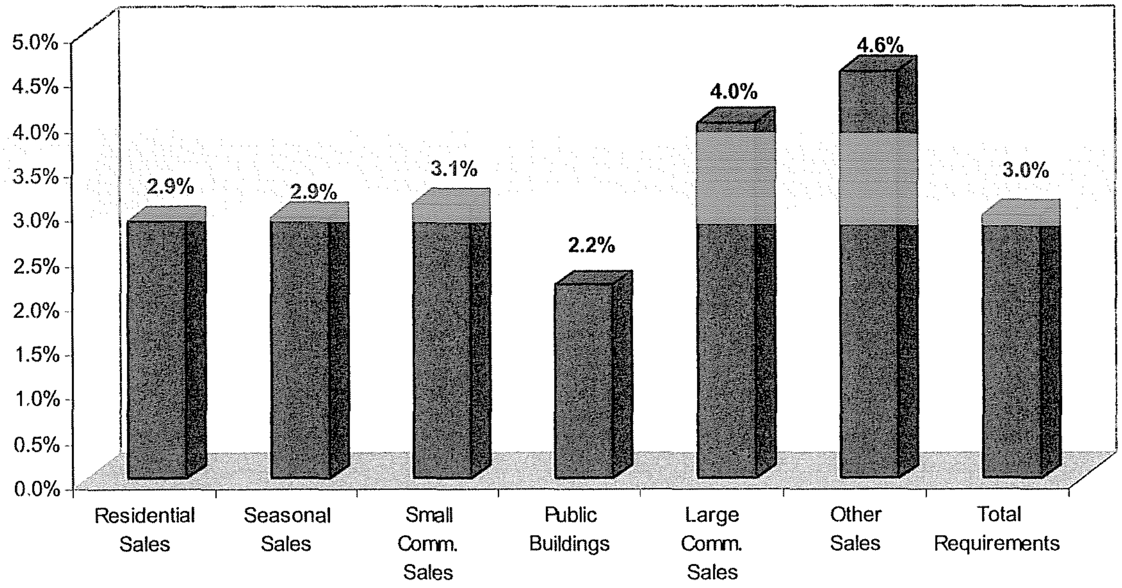


Figure 3-3
Components of Member System Retail Sales

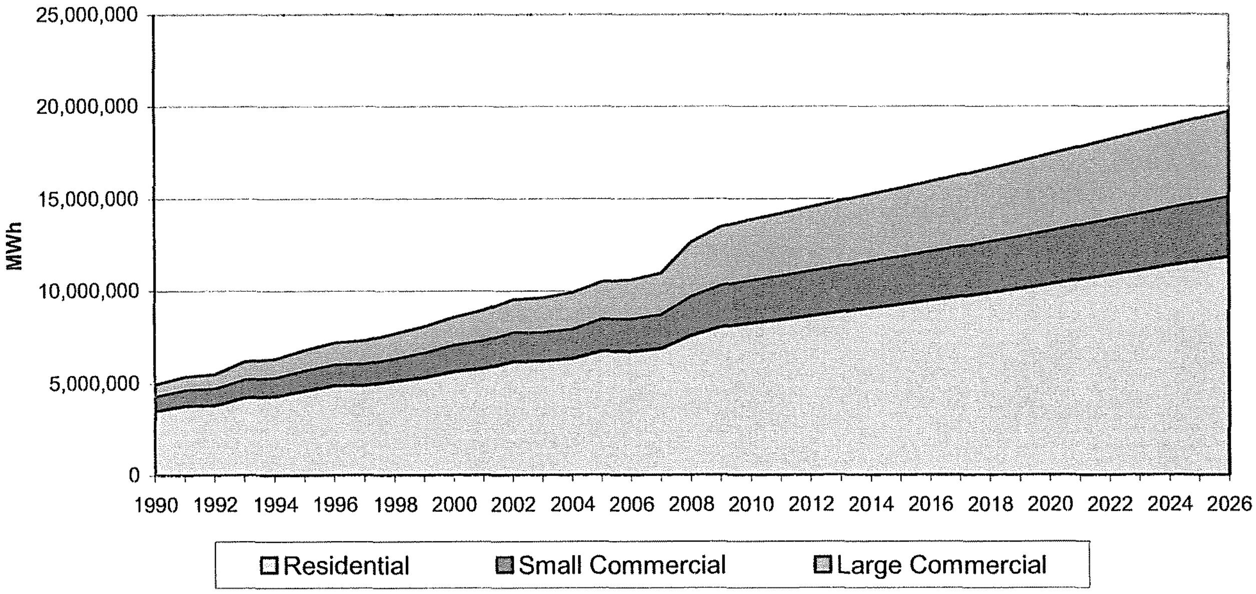


Figure 3-4
EKPC Total Requirements

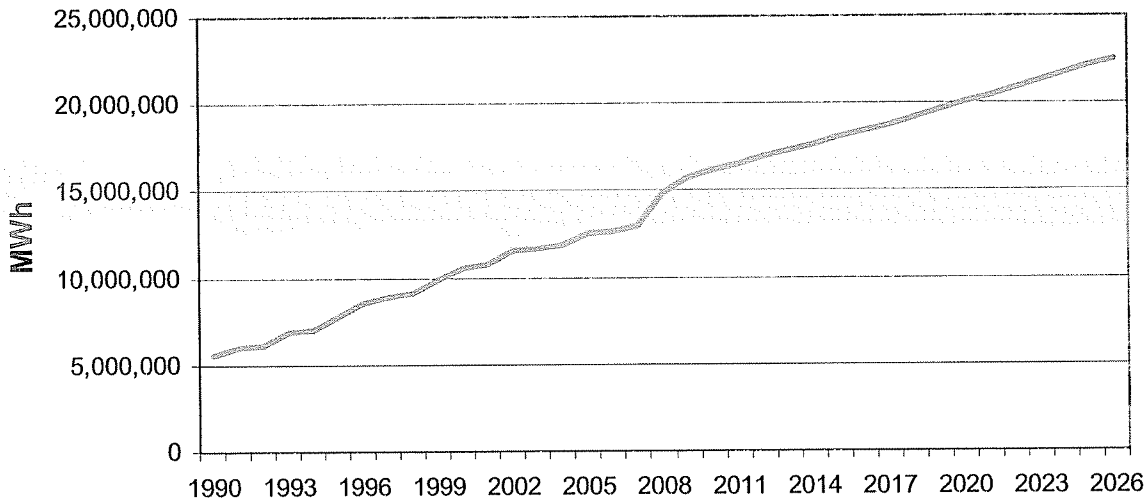


Figure 3-5
Net Peak Demands

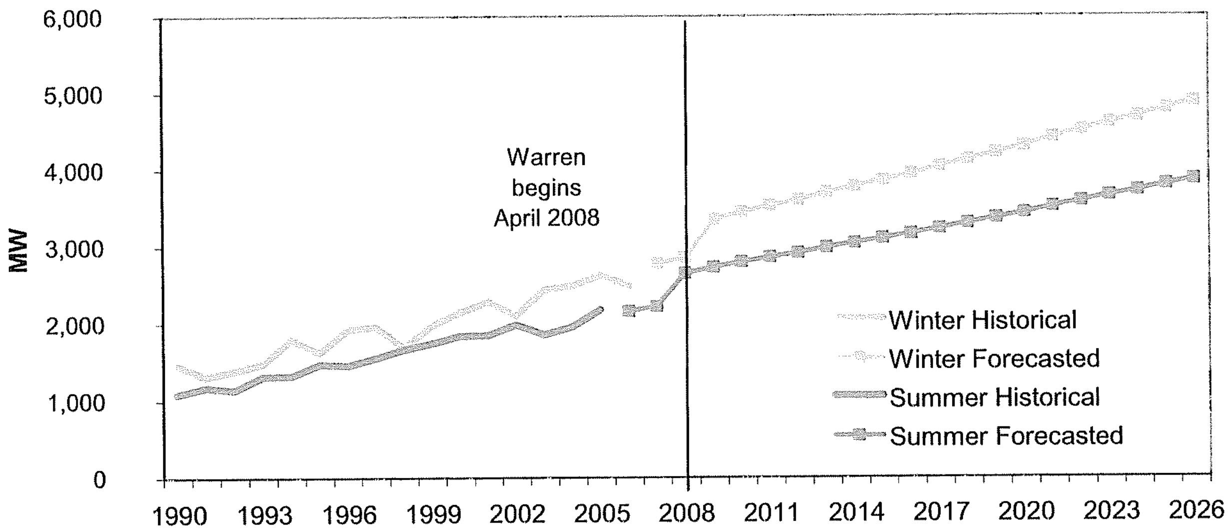


Figure 3-6
Annual System Load Factor
Historical and Forecasted

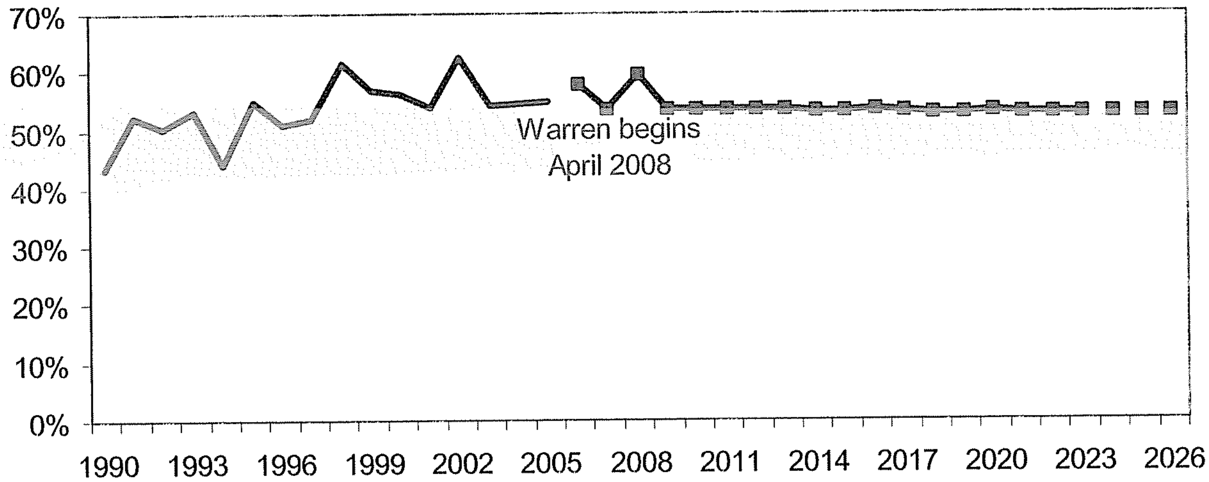


Figure 3-7
Winter Peak Demand
MW Growth 2006-2016

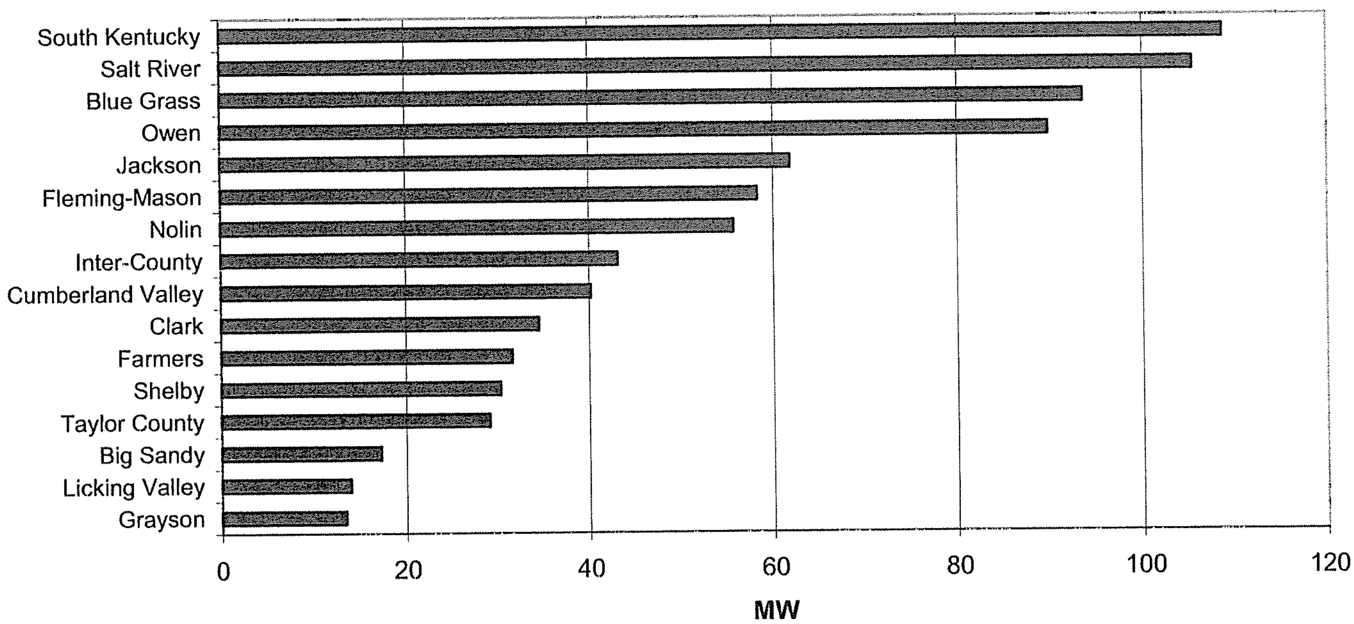


Table 3-2
Member System Average Annual Energy Growth Rates
2006 – 2011

Member Cooperative	Residential Sales (%)	Small Commercial Sales (%)	Large Commercial Sales (%)	Total Sales (%)
Big Sandy	1.8%	2.3%	0.0%	1.9%
Blue Grass	2.8%	3.8%	3.7%	3.1%
Clark	2.4%	2.0%	8.7%	2.5%
Cumberland Valley	2.6%	2.1%	6.1%	3.4%
Farmers	2.4%	2.7%	0.8%	2.1%
Fleming-Mason	2.2%	3.5%	3.2%	3.0%
Grayson	2.0%	2.0%	0.7%	1.9%
Inter-County	2.4%	4.4%	12.2%	3.3%
Jackson Energy	1.7%	2.3%	6.4%	2.2%
Licking Valley	2.0%	1.5%	0.6%	1.8%
Nolin	2.7%	3.3%	4.0%	3.1%
Owen	3.3%	3.7%	2.3%	3.2%
Salt River	3.7%	2.3%	15.1%	5.1%
Shelby	3.2%	3.0%	1.8%	2.7%
South Kentucky	2.6%	3.5%	5.2%	3.1%
Taylor County	2.3%	2.7%	1.6%	2.2%
East Kentucky Power (Includes Warren)	4.7%	6.0%	9.9%	5.6%

Table 3-3
Member System Average Annual Energy Growth Rates
2006 – 2016

Member Cooperative	Residential Sales (%)	Small Commercial Sales (%)	Large Commercial Sales (%)	Total Sales (%)
Big Sandy	1.8%	2.1%	0.0%	1.8%
Blue Grass	2.7%	3.2%	2.6%	2.7%
Clark	2.4%	1.9%	8.2%	2.5%
Cumberland Valley	2.5%	1.9%	3.7%	2.7%
Farmers	2.3%	2.2%	0.8%	1.9%
Fleming-Mason	2.1%	3.2%	2.8%	2.6%
Grayson	1.8%	1.6%	0.6%	1.7%
Inter-County	2.3%	3.8%	8.8%	3.0%
Jackson Energy	1.8%	2.1%	5.7%	2.2%
Licking Valley	1.8%	1.4%	0.7%	1.7%
Nolin	2.6%	2.9%	3.7%	2.9%
Owen	3.3%	3.3%	2.0%	3.1%
Salt River	3.4%	2.2%	7.8%	3.8%
Shelby	2.9%	2.8%	1.6%	2.4%
South Kentucky	2.7%	3.1%	4.3%	3.0%
Taylor County	2.0%	2.4%	1.3%	2.0%
East Kentucky Power (Includes Warren)	3.5%	4.1%	6.0%	3.9%

Table 3-4
Average Annual Energy Growth Rates
2006 – 2026

Member Cooperative	Residential Sales (%)	Small Commercial Sales (%)	Large Commercial Sales (%)	Total Sales (%)
Big Sandy	1.8%	1.9%	4.7%	1.9%
Blue Grass	2.5%	2.8%	2.4%	2.5%
Clark	2.4%	1.8%	4.0%	2.3%
Cumberland Valley	2.5%	1.8%	2.6%	2.4%
Farmers	2.1%	1.8%	1.4%	1.9%
Fleming-Mason	1.9%	2.8%	2.4%	2.3%
Grayson	1.8%	1.7%	2.3%	1.8%
Inter-County	2.2%	3.2%	5.6%	2.6%
Jackson Energy	1.8%	1.9%	4.2%	2.1%
Licking Valley	1.8%	1.3%	2.8%	1.8%
Nolin	2.5%	2.7%	3.1%	2.7%
Owen	3.1%	2.9%	2.2%	2.9%
Salt River	3.1%	2.0%	4.1%	3.1%
Shelby	2.6%	2.5%	1.5%	2.2%
South Kentucky	2.7%	2.7%	3.3%	2.7%
Taylor County	1.8%	2.2%	1.4%	1.9%
East Kentucky Power (Includes Warren)	2.9%	3.1%	4.0%	2.9%

Table 3-5
Monthly Class Energy Sales Forecasts
Excluding Gallatin Steel Sales
2006, 2007, 2008

Year	Month	Residential Sales (MWh)	Small Comm. Sales (MWh)	Large Comm. Sales (MWh)	Other Sales (MWh)	Total Retail Sales (MWh)
2006	1	734,636	143,314	169,921	667	1,048,538
2006	2	705,886	144,296	169,624	662	1,020,468
2006	3	625,183	141,897	172,112	658	939,850
2006	4	514,162	141,340	171,618	654	827,775
2006	5	446,259	141,812	172,770	656	761,497
2006	6	473,558	149,154	180,317	653	803,682
2006	7	543,076	157,550	180,221	656	881,503
2006	8	553,383	161,235	184,912	656	900,187
2006	9	490,556	158,713	183,520	662	833,451
2006	10	437,293	147,095	178,598	665	763,651
2006	11	532,568	144,921	175,665	674	853,828
2006	12	685,715	149,128	177,156	682	1,012,682
Total		6,742,275	1,780,456	2,116,434	7,945	10,647,110
2007	1	761,382	150,440	183,753	677	1,096,252
2007	2	735,886	151,015	182,253	677	1,069,830
2007	3	641,536	148,730	184,327	675	975,268
2007	4	530,365	147,202	183,649	674	861,890
2007	5	456,631	147,234	185,666	675	790,206
2007	6	479,633	154,158	192,086	675	826,552
2007	7	542,721	162,268	191,611	677	897,277
2007	8	554,791	165,480	195,850	678	916,799
2007	9	498,016	162,038	193,555	682	854,290
2007	10	456,721	152,318	189,555	684	799,277
2007	11	548,318	149,975	187,305	689	886,287
2007	12	700,658	153,610	187,951	694	1,042,912
Total		6,906,656	1,844,468	2,257,560	8,157	11,016,841
2008	1	775,751	156,363	192,919	700	1,125,733
2008	2	746,932	156,543	191,577	701	1,095,753
2008	3	656,848	154,805	193,700	700	1,006,053
2008	4	609,177	176,865	249,575	1,126	1,036,743
2008	5	521,153	175,973	253,059	1,136	951,321
2008	6	542,417	184,723	264,515	1,141	992,796
2008	7	614,838	196,182	265,792	1,146	1,077,958
2008	8	632,915	200,552	272,633	1,145	1,107,245
2008	9	571,963	194,802	271,215	1,140	1,039,120
2008	10	530,458	183,102	260,645	1,138	975,343
2008	11	622,743	178,961	257,561	1,134	1,060,399
2008	12	793,602	184,196	254,326	1,134	1,233,258
Total		7,618,797	2,143,068	2,927,518	12,341	12,701,724

Residential sales is the sum of the Residential, Seasonal, and Public Building class sales.

3.5 Major Differences Between EKPC's 2006 and 2004 Load Forecasts

There are three major changes in the 2006 Load Forecast: 1.) Gallatin Steel will be interrupted 360 hours each year as a result of contract negotiations. The 2004 forecast assumed 500 hours. 2.) Based on the most recent End-Use Survey, the assumption for electric furnace saturation is higher than in the 2004 Load Forecast. 3.) Household formation has slowed relative to the 2004 forecast. Table 3-6 shows the differences between the forecasts. Figures 3-7 and 3-8 compare the peak demand projections for the past several forecasts.

Table 3-6

Forecast Comparison
2006 Versus 2004

		2006	2004	Difference
Residential Sales, MWh				
	2007	6,865,831	7,183,613	-317,783
	2012	8,650,448	9,277,560	-627,113
	2017	9,681,304	10,734,638	-1,053,334
Total Commercial and Industrial Sales, MWh				
	2007	4,102,027	4,202,123	-100,095
	2012	5,917,350	6,157,558	-240,208
	2017	6,603,307	6,938,307	-335,000
Gallatin Steel, MWh	2007-2017	982,000	960,000	22,000
Residential Customers				
	2007	477,298	486,697	-9,399
	2012	580,588	600,127	-19,539
	2017	635,513	666,258	-30,745
Firm Winter Peak, MW				
	2007	2,773	2,838	-65
	2012	3,595	3,753	-158
	2017	4,031	4,305	-274
Firm Summer Peak, MW				
	2007	2,213	2,300	-87
	2012	2,907	3,089	-182
	2017	3,225	3,519	-294

Note: Warren becomes member in April 2008.

Figure 3-7
Historical Load Forecast Studies
Winter Peak Demand Projections

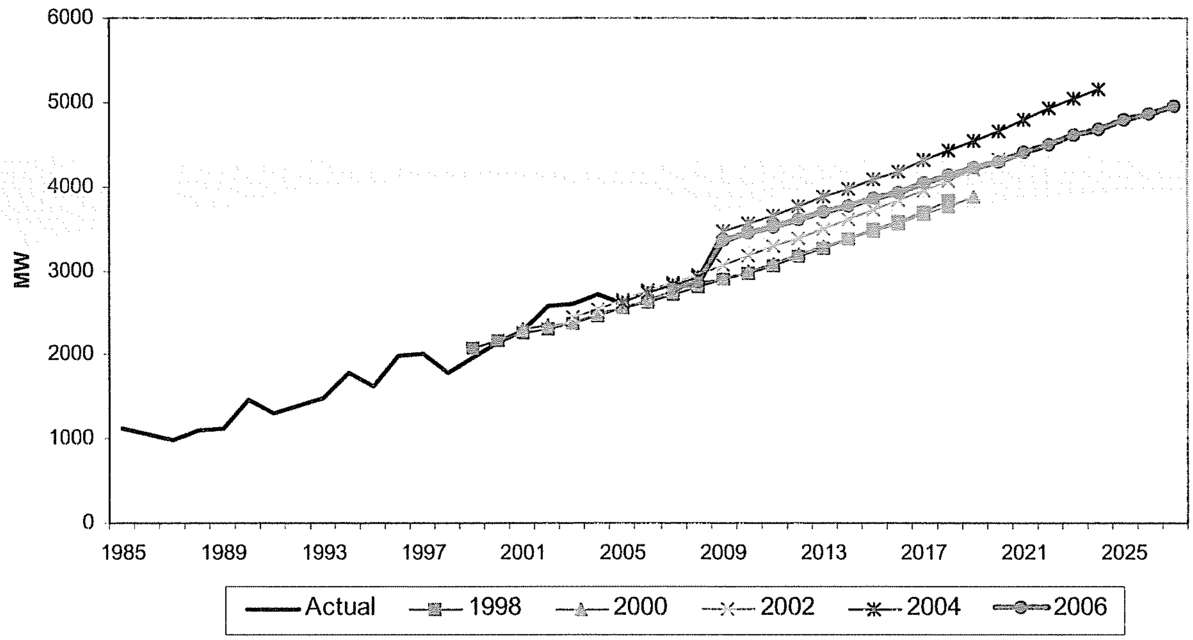
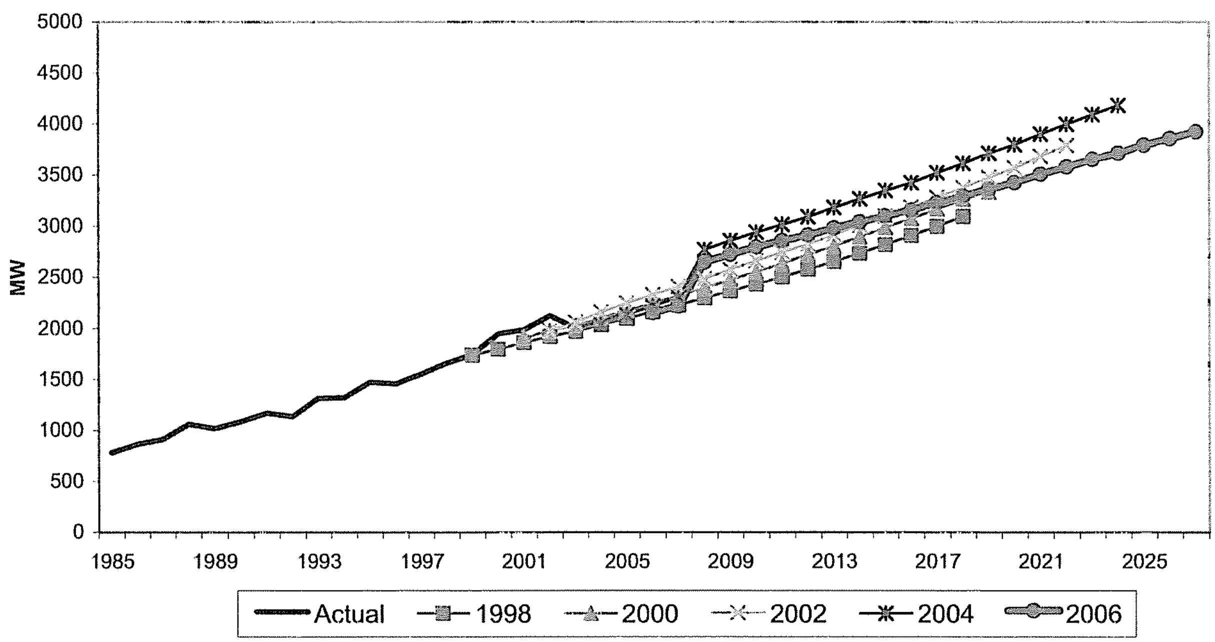


Figure 3-8
Historical Load Forecast Studies
Summer Peak Demand



SECTION 4.0

REGIONAL ECONOMIC MODEL

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Section 4.0
Regional Economic Model

Part of EKPC's load forecast methodology includes regional economic modeling. Historical data on population, income, employment levels, and wages are collected at the county level from the U.S. Bureau of Labor Statistics ("BLS") and the U.S. Bureau of Economic Analysis ("BEA") and historical data on labor force size and the unemployment rate are collected at the county level from state sources. The historical county data are combined into seven economic regions, and are analyzed and projected into the future. EKPC subscribes to the forecast services of Global Insight, an established consulting firm that supplies economic forecasts to thousands of U.S. firms. Regional economic activity is modeled using Global Insight's forecast of the U.S. economy as a driver. Consistent regional forecasts for population, income, and employment are developed. Population forecasts are used to project residential class customers; regional household income is used to project residential sales; and regional economic activity is used to project small commercial sales. The regional model output for the seven regions as well as the SAS code are provided in Appendix B.

A positive aspect for EKPC's regional modeling is that key variables, shown below in Table 4-1, have a common basis from which forecasts are made. That is, the variable forecasts are consistent relative to one another. Population projections are linked to income growth, which is in turn linked to employment growth.

Table 4-1
Key Load Forecast Variables
Percent Change

	1990-2000	2000-2010	2010-2020
Population	10%	7%	7%
Total Employment	24%	7%	8%
Manufacturing Employment	13%	-14%	1%
Total Income	32%	14%	13%
Per Capita Income	20%	6%	6%

An important variable that is projected by the regional model is regional population. Historical population grew rapidly during the seventies and, as Figure 4-1 shows, slowed during the second half of the eighties. Presently, population growth has once again begun to increase at a relatively rapid rate. Overall, EKPC's forecast is for moderate growth in population.

Figure 4-1
Total Population, All Regions

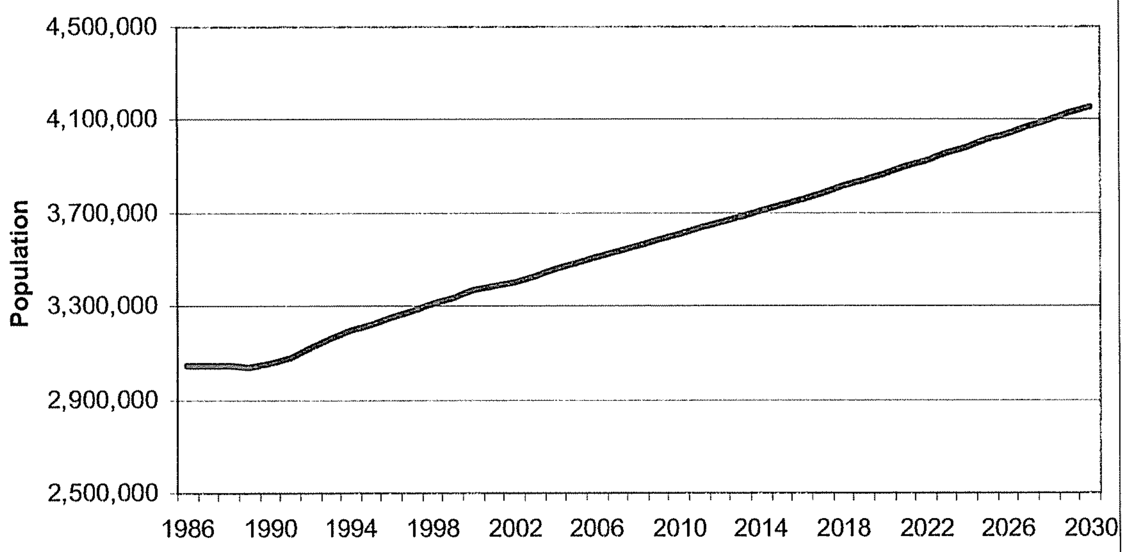


Figure 4-2 illustrates the cyclical nature of income growth, and the sensitivity to the national economy exhibited by EKPC's service area. Whenever employment levels decrease or wage levels fall, personal income will be adversely affected. EKPC's forecast of total regional income is for moderate but steady growth. This variable is important to the load forecast because of its strong effect on appliance purchases.

Figure 4-2
Total Income, All Regions

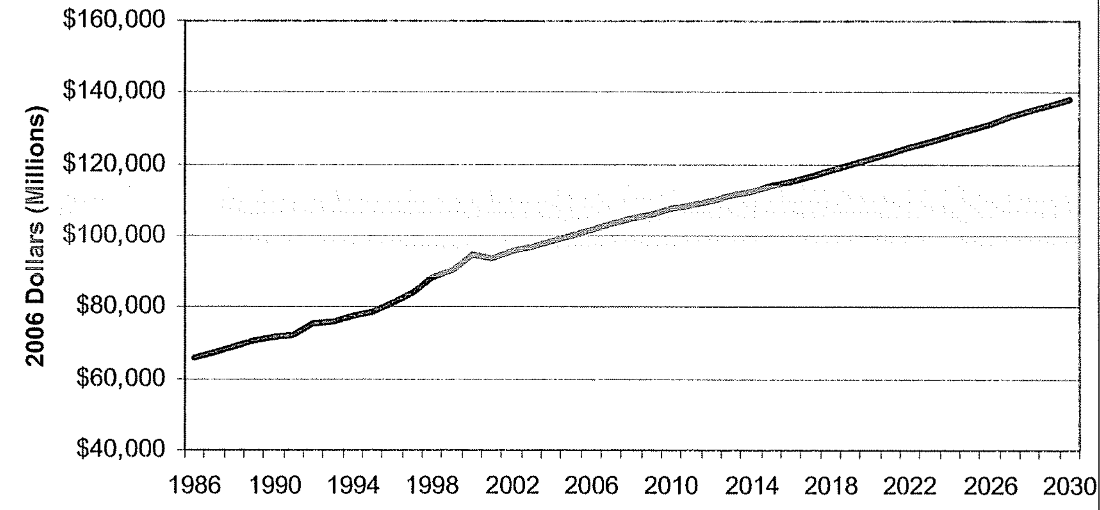
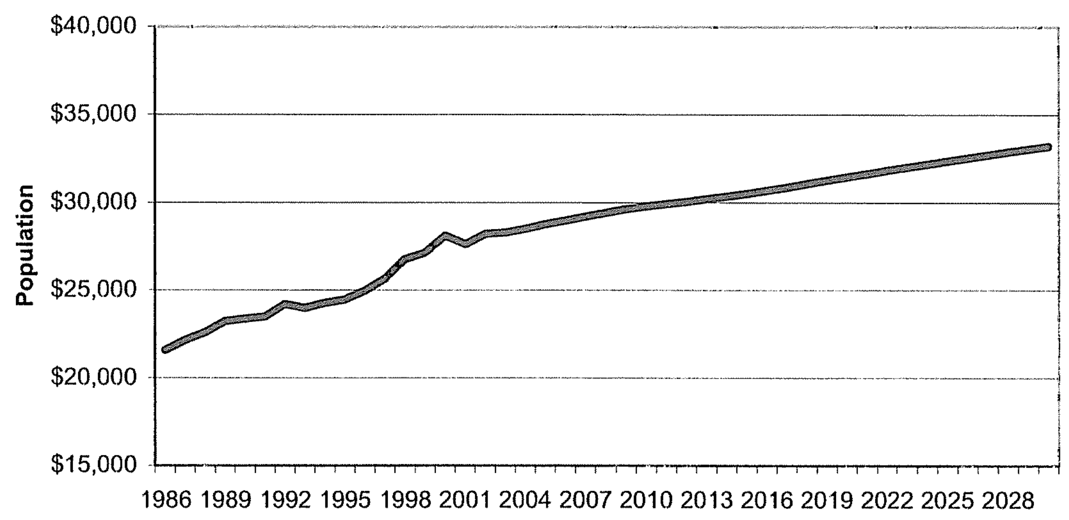


Figure 4-3 represents an interaction of the two previous charts. Per Capita Income (PCY) is defined as personal income divided by total population. In 2006, regional PCY was $29,000. EKPC projects this to increase to $32,500 in constant dollars by 2026.

Figure 4-3
Average Per Capita Income, All Regions



Total regional employment is tied closely to the national economy. The early eighties was a period of depressed job growth. As Figure 4-4 shows, since 1986, however, total employment has grown strongly and EKPC's forecast of total employment levels is for moderate growth. One constraint on jobs creation is the labor force, which should grow more slowly than in the past due to two effects.

Figure 4-4
Total Employment, All Regions

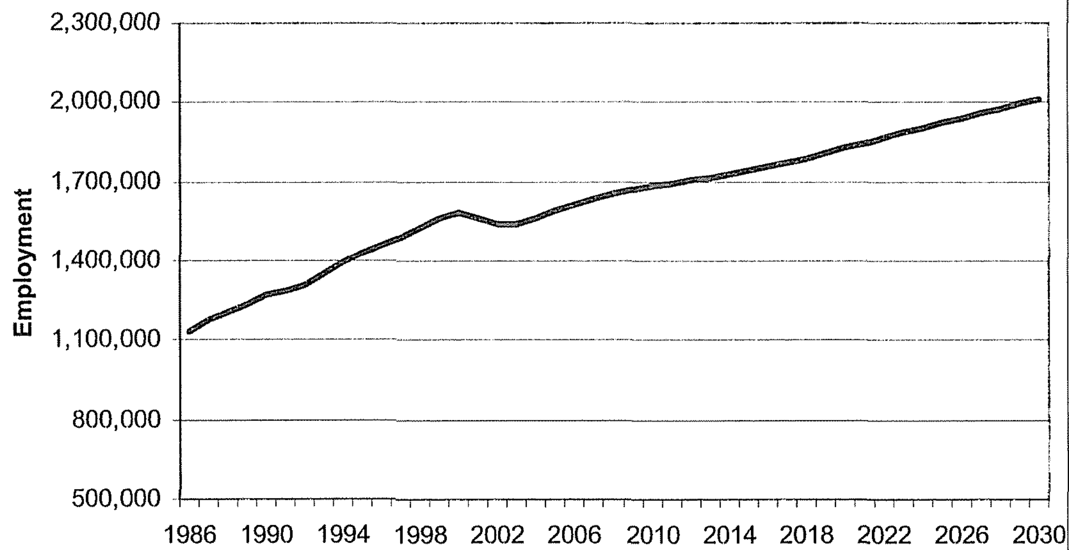
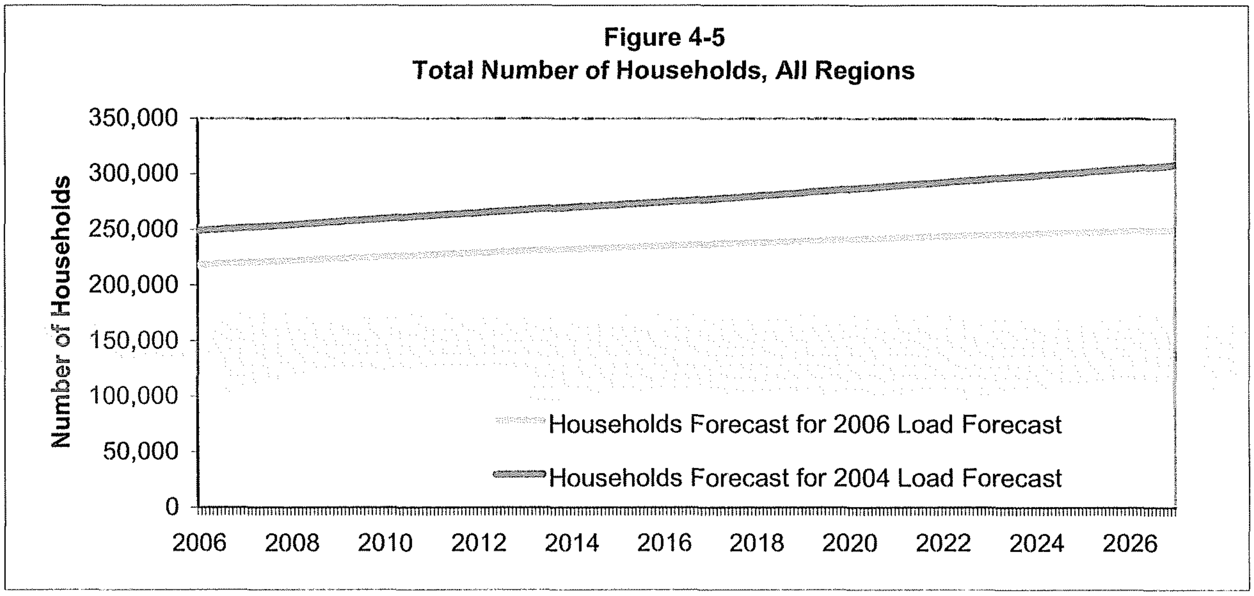


Figure 4-5 shows 2004 and 2006 forecasts of total households. As is shown, the current forecast shows household growth much more moderate than the 2004 forecast. This trend is being seen for surrounding states as well.



Projections of regional economic activity enhance the sales forecasting and strategic planning of EKPC because changes in regional employment and income are important determinants of customer and sales growth. EKPC's regional models use quarterly county-level data to produce regional forecasts of income, employment, wages, population, labor force, and the unemployment rate. The analysis is performed with ordinary least squares regression. Historical regional data are common series and are available from government sources. The quarterly data is then converted to monthly values to use in the load forecasting models.

Some natural regions exist within the EKPC territory. For example, the Central Economic Region defined by EKPC fits closely within the Lexington Standard Metropolitan Statistical Area ("SMSA"). The BEA defines SMSA's as areas of interrelated economic activity that go beyond a single county's boundaries. EKPC's Eastern Region is dominated by the coal mining industry. The Northern Region includes Kentucky counties that border Cincinnati. A list of regions and counties is provided in Table 4-2. Models for these regions provide EKPC with a way of linking the electricity needs of a service area to the rest of the service area's economy in a consistent and reasonable manner. Tables 4-3 through 4-9 report regional economic summaries.

Table 4-2

Regional Economic Model
Counties by Region

Central South	Central North	South	Central	North	North East	East
Allen	Bullitt	Adair	Anderson	Boone	Bath	Bell
Barren	Hardin	Boyle	Bourbon	Bracken	Boyd	Breathitt
Butler	Henry	Casey	Clark	Campbell	Carter	Clay
Cumberland	Jefferson	Garrard	Fayette	Carroll	Elliott	Estill
Edmonson	Larue	Green	Franklin	Gallatin	Fleming	Floyd
Grayson	Meade	Lincoln	Harrison	Grant	Greenup	Harlan
Hart	Nelson	Marion	Jessamine	Kenton	Lawrence	Jackson
Metcalfe	Oldham	McCreary	Madison	Owen	Lewis	Johnson
Monroe	Shelby	Pulaski	Mercer	Pendleton	Mason	Knott
Simpson	Spencer	Russell	Scott		Menifee	Knox
Warren	Trimble	Taylor	Woodford		Montgomery	Laurel
	Washington	Wayne			Nicholas	Lee
					Powell	Leslie
					Robertson	Letcher
					Rowan	Magoffin
						Martin
						Morgan
						Owsley
						Perry
						Pike
						Rockcastle
						Whitley
						Wolfe

Table 4-3

Southern Economic Region History and Forecast Regional Summary														
	Population		**Labor Force**		**Total Employment**		**Unemployment Rate**		**Average Real Wages**		**Regional Income**		**Real Per Capita Income**	
		(%) Change		(%) Change		(%) Change		(%) Change		(%) Change		(%) Change		(%) Change
Actual														
1990	222,596	0.5%	102,517	-0.9%	73,322	2.0%	6.8%	-6.6%	$23,344	-2.1%	$4,116	1.7%	$18,491	1.2%
1991	224,983	1.1%	102,617	0.1%	73,717	0.5%	9.2%	35.8%	$23,654	1.3%	$4,241	3.0%	$18,850	1.9%
1992	228,383	1.5%	103,826	1.2%	76,627	3.9%	7.7%	-16.0%	$23,699	0.2%	$4,492	5.9%	$19,669	4.3%
1993	231,215	1.2%	106,384	2.5%	78,297	2.2%	7.0%	-10.0%	$23,246	-1.9%	$4,478	-0.3%	$19,368	-1.5%
1994	234,324	1.3%	106,212	-0.2%	80,085	2.3%	5.9%	-15.5%	$22,986	-1.1%	$4,576	2.2%	$19,529	0.8%
1995	237,430	1.3%	107,381	1.1%	82,276	2.7%	6.0%	2.6%	$23,206	1.0%	$4,523	-1.2%	$19,049	-2.5%
1996	240,075	1.1%	107,437	0.1%	82,336	0.1%	6.8%	12.4%	$23,326	0.5%	$4,667	3.2%	$19,440	2.1%
1997	242,082	0.8%	109,562	2.0%	82,257	-0.1%	7.9%	16.2%	$23,915	2.5%	$4,940	5.9%	$20,407	5.0%
1998	244,142	0.9%	111,775	2.0%	80,254	-2.4%	10.0%	26.3%	$24,504	2.5%	$5,165	4.5%	$21,156	3.7%
1999	246,214	0.8%	109,510	-2.0%	80,966	0.9%	6.9%	-30.4%	$25,186	2.8%	$5,186	0.4%	$21,061	-0.4%
2000	248,478	0.9%	110,838	1.2%	85,552	5.7%	4.6%	-33.6%	$24,701	-1.9%	$5,501	6.1%	$22,137	5.1%
2001	249,784	0.5%	113,076	2.0%	84,420	-1.3%	6.6%	42.9%	$24,395	-1.2%	$5,525	0.4%	$22,120	-0.1%
2002	252,132	0.9%	111,837	-1.1%	83,184	-1.5%	6.6%	0.8%	$25,256	3.5%	$5,635	2.0%	$22,349	1.0%
2003	254,340	0.9%	118,912	6.3%	84,155	1.2%	7.0%	4.9%	$25,296	0.2%	$5,623	-0.2%	$22,109	-1.1%
2004	256,709	0.9%	119,767	0.7%	85,502	1.6%	6.8%	-2.6%	$25,292	0.0%	$5,695	1.3%	$22,185	0.3%
2005	259,127	0.9%	120,583	0.7%	86,603	1.3%	6.4%	-5.3%	$25,394	0.4%	$5,784	1.6%	$22,321	0.6%
Forecast														
2006	261,555	0.9%	121,422	0.7%	87,807	1.4%	6.2%	-3.2%	$25,292	-0.4%	$5,880	1.7%	$22,479	0.7%
2007	263,960	0.9%	122,241	0.7%	88,935	1.3%	6.2%	0.2%	$25,394	0.4%	$5,983	1.8%	$22,665	0.8%
2008	266,325	0.9%	123,013	0.6%	89,888	1.1%	6.1%	-1.7%	$25,490	0.4%	$6,087	1.7%	$22,856	0.8%
2009	268,666	0.9%	123,764	0.6%	90,768	1.0%	6.0%	-1.1%	$25,578	0.3%	$6,194	1.8%	$23,054	0.9%
2010	270,951	0.9%	124,442	0.5%	91,364	0.7%	6.1%	1.2%	$25,657	0.3%	$6,298	1.7%	$23,243	0.8%
Long-Term Forecast														
2015	282,217	0.8%	127,756	0.5%	94,163	0.6%	6.2%	0.4%	$25,994	0.3%	$6,805	1.6%	$24,112	0.7%
2020	293,610	0.8%	131,444	0.6%	98,605	0.9%	6.0%	-0.9%	$26,093	0.1%	$7,353	1.6%	$25,043	0.8%
2025	304,974	0.8%	135,163	0.6%	103,230	0.9%	6.0%	0.1%	$26,148	0.0%	$7,909	1.5%	$25,935	0.7%
2030	316,248	0.7%	138,778	0.5%	107,464	0.8%	6.0%	0.0%	$26,181	0.0%	$8,450	1.3%	$26,719	0.6%

Notes: ***Wages & Per Capita Income are in constant 2006 dollars; Income is in millions of constant 2005 dollars.***
Growth rates are average annual changes. Data for 2004 and 2005 are simulated.

Table 4-4

Eastern Economic Region History and Forecast														
Regional Summary														
	Population		**Labor Force**		**Total Employment**		**Unemployment Rate**		**Average Real Wages**		**Regional Income**		**Real Per Capita Income**	
		(%) Change		(%) Change		(%) Change		(%) Change		(%) Change		(%) Change		(%) Change
Actual														
1990	540,824	-0.5%	190,058	2.5%	144,054	3.4%	9.0%	-3.5%	$25,743	-1.6%	$8,910	1.1%	$16,475	1.7%
1991	544,407	0.7%	192,903	1.5%	144,936	0.6%	12.0%	33.8%	$25,411	-1.3%	$9,096	2.1%	$16,707	1.4%
1992	547,802	0.6%	193,612	0.4%	145,141	0.1%	11.3%	-5.4%	$25,828	1.6%	$9,402	3.4%	$17,163	2.7%
1993	551,087	0.6%	195,843	1.2%	148,381	2.2%	10.0%	-12.1%	$25,735	-0.4%	$9,416	0.2%	$17,087	-0.4%
1994	553,065	0.4%	196,987	0.6%	150,867	1.7%	8.9%	-10.8%	$25,741	0.0%	$9,522	1.1%	$17,217	0.8%
1995	555,088	0.4%	201,264	2.2%	155,081	2.8%	9.1%	2.0%	$25,511	-0.9%	$9,584	0.6%	$17,265	0.3%
1996	554,460	-0.1%	199,145	-1.1%	154,776	-0.2%	9.5%	4.7%	$25,641	0.5%	$9,674	0.9%	$17,447	1.1%
1997	554,363	0.0%	202,287	1.6%	157,169	1.5%	8.2%	-13.5%	$26,087	1.7%	$10,069	4.1%	$18,163	4.1%
1998	554,044	-0.1%	201,723	-0.3%	159,377	1.4%	6.8%	-17.7%	$26,377	1.1%	$10,284	2.1%	$18,562	2.2%
1999	553,832	0.0%	204,002	1.1%	159,825	0.3%	6.9%	2.2%	$26,516	0.5%	$10,479	1.9%	$18,921	1.9%
2000	552,926	-0.2%	202,132	-0.9%	158,377	-0.9%	6.4%	-7.6%	$26,390	-0.5%	$10,737	2.5%	$19,418	2.6%
2001	551,463	-0.3%	202,586	0.2%	159,095	0.5%	6.6%	3.9%	$26,200	-0.7%	$11,012	2.6%	$19,968	2.8%
2002	554,005	0.5%	201,554	-0.5%	157,185	-1.2%	7.2%	8.3%	$26,520	1.2%	$11,137	1.1%	$20,102	0.7%
2003	554,238	0.0%	203,166	0.8%	155,124	-1.3%	8.3%	15.7%	$26,624	0.4%	$11,109	-0.2%	$20,044	-0.3%
2004	555,666	0.3%	205,488	1.1%	159,456	2.8%	8.7%	4.2%	$26,654	0.1%	$11,237	1.2%	$20,223	0.9%
2005	557,768	0.4%	207,099	0.8%	162,464	1.9%	8.1%	-6.6%	$26,767	0.4%	$11,330	0.8%	$20,312	0.4%
Forecast														
2006	559,879	0.4%	208,737	0.8%	165,519	1.9%	7.7%	-4.1%	$26,654	-0.4%	$11,434	0.9%	$20,422	0.5%
2007	560,254	0.1%	209,187	0.2%	166,360	0.5%	7.8%	0.3%	$26,767	0.4%	$11,562	1.1%	$20,638	1.1%
2008	559,983	0.0%	209,116	0.0%	166,228	-0.1%	7.6%	-2.2%	$26,831	0.2%	$11,694	1.1%	$20,882	1.2%
2009	559,782	0.0%	208,980	-0.1%	165,972	-0.2%	7.5%	-1.4%	$26,870	0.1%	$11,829	1.2%	$21,132	1.2%
2010	559,699	0.0%	208,770	-0.1%	165,581	-0.2%	7.6%	1.6%	$26,899	0.1%	$11,969	1.2%	$21,385	1.2%
Long-Term Forecast														
2015	560,660	0.0%	208,498	0.0%	165,074	-0.1%	7.8%	0.5%	$26,970	0.1%	$12,716	1.2%	$22,680	1.2%
2020	562,110	0.1%	210,100	0.2%	168,064	0.4%	7.4%	-1.1%	$26,993	0.0%	$13,601	1.4%	$24,196	1.3%
2025	564,514	0.1%	212,857	0.3%	173,208	0.6%	7.4%	0.1%	$26,999	0.0%	$14,557	1.4%	$25,786	1.3%
2030	567,274	0.1%	215,400	0.2%	177,954	0.5%	7.4%	0.0%	$27,001	0.0%	$15,500	1.3%	$27,324	1.2%
Notes:	*Wages & Per Capita Income are in constant 2006 dollars; Income is in millions of constant 2005 dollars.*													
	Growth rates are average annual changes. Data for 2004 and 2005 are simulated.													

Table 4-5

North Eastern Economic Region History and Forecast
Regional Summary

	Population		Labor Force		Total Employment		Unemployment Rate		Average Real Wages		Regional Income		Real Per Capita Income	
		(%) Change		(%) Change		(%) Change		(%) Change		(%) Change		(%) Change		(%) Change
Actual														
1990	249,842	-0.2%	111,918	5.7%	75,323	4.1%	8.6%	6.5%	$27,581	-2.6%	$4,744	0.8%	$18,987	1.1%
1991	251,534	0.7%	112,873	0.9%	75,144	-0.2%	11.4%	32.7%	$26,829	-2.7%	$4,816	1.5%	$19,147	0.8%
1992	253,735	0.9%	112,902	0.0%	77,721	3.4%	10.4%	-8.4%	$27,420	2.2%	$4,993	3.7%	$19,678	2.8%
1993	255,654	0.8%	114,691	1.6%	77,336	-0.5%	11.0%	5.3%	$27,052	-1.3%	$4,920	-1.5%	$19,246	-2.2%
1994	257,025	0.5%	114,732	0.0%	78,883	2.0%	9.3%	-15.1%	$27,187	0.5%	$5,003	1.7%	$19,466	1.1%
1995	258,584	0.6%	116,654	1.7%	80,808	2.4%	8.7%	-6.7%	$26,965	-0.8%	$4,980	-0.5%	$19,259	-1.1%
1996	260,129	0.6%	116,499	-0.1%	82,449	2.0%	7.9%	-9.5%	$27,095	0.5%	$5,110	2.6%	$19,645	2.0%
1997	261,885	0.7%	120,218	3.2%	83,924	1.8%	8.0%	1.9%	$27,328	0.9%	$5,301	3.7%	$20,243	3.0%
1998	263,674	0.7%	121,876	1.4%	85,737	2.2%	6.7%	-15.9%	$27,219	-0.4%	$5,496	3.7%	$20,842	3.0%
1999	265,250	0.6%	123,811	1.6%	86,435	0.8%	7.1%	5.2%	$27,387	0.6%	$5,536	0.7%	$20,872	0.1%
2000	266,781	0.6%	122,111	-1.4%	87,664	1.4%	6.2%	-12.4%	$27,278	-0.4%	$5,829	5.3%	$21,849	4.7%
2001	268,031	0.5%	122,316	0.2%	86,834	-0.9%	7.7%	23.4%	$27,429	0.6%	$5,704	-2.1%	$21,281	-2.6%
2002	268,990	0.4%	120,773	-1.3%	86,943	0.1%	6.6%	-14.4%	$28,039	2.2%	$5,881	3.1%	$21,862	2.7%
2003	270,356	0.5%	125,429	3.9%	89,410	2.8%	7.1%	8.8%	$28,262	0.8%	$5,990	1.9%	$22,157	1.3%
2004	270,715	0.1%	125,728	0.2%	89,757	0.4%	6.3%	-11.0%	$28,609	1.2%	$6,036	0.8%	$22,297	0.6%
2005	271,701	0.4%	126,543	0.6%	90,703	1.1%	5.8%	-9.3%	$28,808	0.7%	$6,078	0.7%	$22,370	0.3%
Forecast														
2006	272,759	0.4%	127,452	0.7%	91,759	1.2%	5.4%	-6.0%	$28,609	-0.7%	$6,127	0.8%	$22,464	0.4%
2007	273,790	0.4%	128,380	0.7%	92,836	1.2%	5.4%	0.5%	$28,808	0.7%	$6,188	1.0%	$22,600	0.6%
2008	274,734	0.3%	129,191	0.6%	93,778	1.0%	5.3%	-3.2%	$28,942	0.5%	$6,246	0.9%	$22,736	0.6%
2009	275,564	0.3%	129,926	0.6%	94,631	0.9%	5.1%	-2.1%	$29,029	0.3%	$6,309	1.0%	$22,895	0.7%
2010	276,368	0.3%	130,488	0.4%	95,284	0.7%	5.3%	2.4%	$29,097	0.2%	$6,371	1.0%	$23,053	0.7%
Long-Term Forecast														
2015	280,228	0.3%	133,083	0.4%	98,297	0.6%	5.5%	0.7%	$29,226	0.1%	$6,688	1.0%	$23,868	0.7%
2020	284,335	0.3%	137,055	0.6%	102,908	0.9%	5.0%	-1.7%	$29,314	0.1%	$7,076	1.1%	$24,887	0.8%
2025	288,583	0.3%	141,478	0.6%	108,043	1.0%	5.1%	0.2%	$29,346	0.0%	$7,495	1.2%	$25,971	0.9%
2030	292,834	0.3%	145,469	0.6%	112,678	0.8%	5.1%	0.0%	$29,352	0.0%	$7,899	1.1%	$26,976	0.8%

Notes: Wages & Per Capita Income are in constant 2006 dollars; Income is in millions of constant 2005 dollars.
Growth rates are average annual changes. Data for 2004 and 2005 are simulated.

Table 4-6

Central South Economic Region History and Forecast Regional Summary														
	Population		Labor Force		Total Employment		Unemployment Rate		Average Real Wages		Regional Income		Real Per Capita Income	
		(%) Change		(%) Change		(%) Change		(%) Change		(%) Change		(%) Change		(%) Change
Actual														
1990	226,711	0.7%	113,838	-2.7%	109,695	2.7%	7.5%	7.2%	$22,884	-1.9%	$4,414	-1.7%	$19,468	-2.4%
1991	229,321	1.2%	113,853	0.0%	111,285	1.4%	8.2%	10.1%	$22,136	-3.3%	$4,575	3.7%	$19,950	2.5%
1992	232,201	1.3%	115,243	1.2%	117,077	5.2%	6.9%	-15.9%	$22,710	2.6%	$4,868	6.4%	$20,964	5.1%
1993	236,827	2.0%	117,778	2.2%	122,731	4.8%	5.8%	-15.9%	$22,672	-0.2%	$4,948	1.6%	$20,892	-0.3%
1994	240,359	1.5%	120,351	2.2%	130,239	6.1%	4.5%	-22.0%	$22,673	0.0%	$5,203	5.1%	$21,645	3.6%
1995	244,602	1.8%	123,689	2.8%	133,972	2.9%	5.3%	16.0%	$23,517	3.7%	$5,239	0.7%	$21,417	-1.0%
1996	247,987	1.4%	125,497	1.5%	134,605	0.5%	6.9%	31.0%	$24,004	2.1%	$5,398	3.0%	$21,767	1.6%
1997	251,565	1.4%	127,414	1.5%	137,919	2.5%	6.1%	-10.9%	$24,460	1.9%	$5,666	5.0%	$22,521	3.5%
1998	255,137	1.4%	127,889	0.4%	142,364	3.2%	4.7%	-22.9%	$24,888	1.7%	$5,869	3.6%	$23,003	2.1%
1999	257,675	1.0%	130,992	2.4%	147,107	3.3%	4.9%	3.2%	$25,186	1.2%	$5,958	1.5%	$23,122	0.5%
2000	260,445	1.1%	130,526	-0.4%	148,598	1.0%	4.4%	-9.2%	$24,991	-0.8%	$6,273	5.3%	$24,084	4.2%
2001	261,936	0.6%	129,820	-0.5%	145,355	-2.2%	5.9%	33.3%	$24,764	-0.9%	$6,082	-3.0%	$23,218	-3.6%
2002	263,616	0.6%	128,970	-0.7%	145,923	0.4%	5.6%	-4.7%	$25,374	2.5%	$6,140	1.0%	$23,291	0.3%
2003	266,440	1.1%	133,235	3.3%	148,030	1.4%	6.3%	11.6%	$25,721	1.4%	$6,228	1.4%	$23,375	0.4%
2004	269,406	1.1%	134,674	1.1%	150,716	1.8%	6.4%	2.1%	$25,703	-0.1%	$6,316	1.4%	$23,443	0.3%
2005	271,802	0.9%	135,984	1.0%	153,416	1.8%	7.0%	8.5%	$25,839	0.5%	$6,423	1.7%	$23,633	0.8%
Forecast														
2006	274,313	0.9%	137,426	1.1%	156,496	2.0%	6.9%	-0.1%	$25,703	-0.5%	$6,527	1.6%	$23,796	0.7%
2007	277,044	1.0%	138,795	1.0%	159,128	1.7%	7.0%	0.2%	$25,839	0.5%	$6,621	1.4%	$23,898	0.4%
2008	279,735	1.0%	140,101	0.9%	161,569	1.5%	6.9%	-0.6%	$25,954	0.4%	$6,714	1.4%	$24,001	0.4%
2009	282,385	0.9%	141,263	0.8%	163,525	1.2%	6.9%	-0.8%	$26,051	0.4%	$6,799	1.3%	$24,078	0.3%
2010	284,991	0.9%	142,258	0.7%	164,915	0.9%	6.9%	0.0%	$26,138	0.3%	$6,879	1.2%	$24,139	0.3%
Long-Term Forecast														
2015	297,793	0.9%	146,797	0.6%	170,490	0.7%	6.9%	0.0%	$26,565	0.3%	$7,229	1.0%	$24,277	0.1%
2020	310,435	0.8%	152,523	0.8%	180,473	1.1%	6.8%	0.0%	$26,790	0.2%	$7,630	1.1%	$24,579	0.2%
2025	323,316	0.8%	158,403	0.8%	190,813	1.1%	6.8%	0.0%	$26,994	0.2%	$8,020	1.0%	$24,807	0.2%
2030	336,643	0.8%	163,860	0.7%	199,254	0.9%	6.8%	0.0%	$27,189	0.1%	$8,403	0.9%	$24,962	0.1%

Notes: Wages & Per Capita Income are in constant 2006 dollars; Income is in millions of constant 2005 dollars. Growth rates are average annual changes. Data for 2004 and 2005 are simulated.

Table 4-7

	Central North Economic Region History and Forecast Regional Summary														
	Population	(%) Change	Labor Force	(%) Change	Total Employment	(%) Change	Unemployment Rate	(%) Change	Average Real Wages	(%) Change	Regional Income	(%) Change	Real Per Capita Income	(%) Change
Actual														
1990	964,002	0.4%	494,930	-2.0%	468,383	3.1%	5.0%	-11.5%	$29,174	-0.6%	$26,677	0.5%	$27,673	0.0%
1991	967,773	0.4%	487,991	-1.4%	467,253	-0.2%	6.1%	20.4%	$29,239	0.2%	$26,826	0.6%	$27,719	0.2%
1992	975,464	0.8%	492,143	0.9%	474,695	1.6%	5.5%	-9.1%	$30,554	4.5%	$27,908	4.0%	$28,610	3.2%
1993	990,659	1.6%	500,123	1.6%	494,158	4.1%	4.9%	-11.4%	$30,764	0.7%	$28,023	0.4%	$28,287	-1.1%
1994	1,000,603	1.0%	507,991	1.6%	506,843	2.6%	4.3%	-12.8%	$30,164	-2.0%	$28,625	2.1%	$28,608	1.1%
1995	1,009,902	0.9%	518,420	2.1%	517,747	2.2%	4.5%	4.7%	$30,981	2.7%	$29,253	2.2%	$28,966	1.3%
1996	1,015,901	0.6%	518,000	-0.1%	526,646	1.7%	4.6%	2.8%	$31,439	1.5%	$29,995	2.5%	$29,526	1.9%
1997	1,024,142	0.8%	533,730	3.0%	534,561	1.5%	4.5%	-2.7%	$32,041	1.9%	$30,730	2.4%	$30,006	1.6%
1998	1,032,925	0.9%	539,000	1.0%	547,361	2.4%	3.6%	-19.1%	$33,452	4.4%	$32,828	6.8%	$31,781	5.9%
1999	1,043,819	1.1%	552,734	2.5%	559,653	2.2%	3.8%	5.6%	$34,438	2.9%	$33,450	1.9%	$32,045	0.8%
2000	1,054,288	1.0%	562,907	1.8%	565,970	1.1%	3.6%	-5.9%	$34,533	0.3%	$34,917	4.4%	$33,119	3.4%
2001	1,060,834	0.6%	554,875	-1.4%	556,479	-1.7%	4.7%	31.5%	$34,714	0.5%	$34,604	-0.9%	$32,620	-1.5%
2002	1,067,926	0.7%	545,484	-1.7%	543,802	-2.3%	5.5%	16.5%	$35,106	1.1%	$35,945	3.9%	$33,659	3.2%
2003	1,076,288	0.8%	537,325	-1.5%	540,482	-0.6%	5.9%	8.2%	$35,596	1.4%	$36,356	1.1%	$33,779	0.4%
2004	1,084,605	0.8%	542,116	0.9%	547,046	1.2%	5.1%	-14.6%	$35,996	1.1%	$36,867	1.4%	$33,991	0.6%
2005	1,091,625	0.6%	548,273	1.1%	556,333	1.7%	5.1%	0.3%	$36,426	1.2%	$37,469	1.6%	$34,324	1.0%
Forecast														
2006	1,098,806	0.7%	554,161	1.1%	565,105	1.6%	5.1%	0.2%	$35,996	-1.2%	$38,047	1.5%	$34,626	0.9%
2007	1,106,385	0.7%	559,643	1.0%	573,065	1.4%	5.1%	0.5%	$36,426	1.2%	$38,629	1.5%	$34,914	0.8%
2008	1,113,740	0.7%	565,297	1.0%	581,383	1.5%	5.1%	-0.6%	$36,769	0.9%	$39,159	1.4%	$35,160	0.7%
2009	1,121,504	0.7%	570,169	0.9%	588,219	1.2%	5.0%	-1.0%	$37,042	0.7%	$39,666	1.3%	$35,368	0.6%
2010	1,129,719	0.7%	574,165	0.7%	593,399	0.9%	5.0%	0.1%	$37,281	0.6%	$40,102	1.1%	$35,498	0.4%
Long-Term Forecast														
2015	1,171,623	0.7%	592,266	0.6%	615,771	0.7%	5.0%	-0.1%	$38,370	0.6%	$42,070	1.0%	$35,907	0.2%
2020	1,216,391	0.8%	617,126	0.8%	649,461	1.1%	5.0%	-0.2%	$38,995	0.3%	$44,473	1.1%	$36,562	0.4%
2025	1,267,709	0.8%	644,495	0.9%	686,080	1.1%	5.0%	0.2%	$39,474	0.2%	$46,981	1.1%	$37,060	0.3%
2030	1,320,322	0.8%	670,189	0.8%	719,430	1.0%	5.0%	-0.1%	$39,946	0.2%	$49,359	1.0%	$37,384	0.2%

Notes: ***Wages & Per Capita Income are in constant 2006 dollars; Income is in millions of constant 2005 dollars. Growth rates are average annual changes. Data for 2004 and 2005 are simulated.***

Table 4-8

Central Economic Region History and Forecast Regional Summary														
	Population	(%) Change	Labor Force	(%) Change	Total Employment	(%) Change	Unemployment Rate	(%) Change	Average Real Wages	(%) Change	Regional Income	(%) Change	Real Per Capita Income	(%) Change
Actual														
1990	507,555	1.4%	276,282	0.2%	285,958	1.9%	4.1%	-4.7%	$30,299	0.5%	$14,118	3.2%	$27,816	1.7%
1991	514,409	1.4%	271,734	-1.6%	288,307	0.8%	4.6%	12.9%	$30,112	-0.6%	$14,274	1.1%	$27,748	-0.2%
1992	523,886	1.8%	273,863	0.8%	291,920	1.3%	4.3%	-6.5%	$30,653	1.8%	$14,805	3.7%	$28,259	1.8%
1993	532,304	1.6%	281,873	2.9%	297,060	1.8%	3.9%	-8.7%	$30,237	-1.4%	$14,912	0.7%	$28,013	-0.9%
1994	539,527	1.4%	285,020	1.1%	303,416	2.1%	3.7%	-5.1%	$30,206	-0.1%	$15,114	1.4%	$28,014	0.0%
1995	545,745	1.2%	289,461	1.6%	305,346	0.6%	3.0%	-18.8%	$30,985	2.6%	$15,627	3.4%	$28,635	2.2%
1996	553,226	1.4%	291,237	0.6%	311,986	2.2%	3.1%	3.3%	$31,386	1.3%	$16,189	3.6%	$29,262	2.2%
1997	559,143	1.1%	301,434	3.5%	321,251	3.0%	3.2%	0.8%	$31,966	1.8%	$16,729	3.3%	$29,918	2.2%
1998	567,001	1.4%	305,322	1.3%	330,205	2.8%	2.6%	-19.0%	$32,715	2.3%	$17,691	5.8%	$31,201	4.3%
1999	574,583	1.3%	312,447	2.3%	338,261	2.4%	2.4%	-6.9%	$33,190	1.5%	$18,358	3.8%	$31,950	2.4%
2000	580,792	1.1%	314,251	0.6%	341,397	0.9%	2.4%	-1.1%	$33,047	-0.4%	$19,063	3.8%	$32,822	2.7%
2001	584,413	0.6%	304,969	-3.0%	333,533	-2.3%	3.6%	51.1%	$33,327	0.8%	$18,607	-2.4%	$31,839	-3.0%
2002	587,178	0.5%	299,604	-1.8%	328,994	-1.4%	4.0%	12.7%	$34,137	2.4%	$19,010	2.2%	$32,375	1.7%
2003	592,935	1.0%	313,629	4.7%	326,826	-0.7%	5.0%	25.6%	$34,495	1.0%	$19,196	1.0%	$32,375	0.0%
2004	600,477	1.3%	316,303	0.9%	330,196	1.0%	4.4%	-12.3%	$34,705	0.6%	$19,669	2.5%	$32,756	1.2%
2005	604,932	0.7%	318,618	0.7%	333,113	0.9%	5.0%	14.1%	$34,983	0.8%	$20,065	2.0%	$33,169	1.3%
Forecast														
2006	609,779	0.8%	321,221	0.8%	336,393	1.0%	5.1%	0.5%	$34,705	-0.8%	$20,357	1.5%	$33,384	0.6%
2007	614,793	0.8%	323,918	0.8%	339,792	1.0%	5.1%	0.6%	$34,983	0.8%	$20,635	1.4%	$33,564	0.5%
2008	619,754	0.8%	326,260	0.7%	342,743	0.9%	5.1%	-0.3%	$35,238	0.7%	$20,919	1.4%	$33,754	0.6%
2009	625,005	0.8%	328,502	0.7%	345,568	0.8%	5.0%	-0.4%	$35,474	0.7%	$21,191	1.3%	$33,905	0.4%
2010	630,538	0.9%	330,469	0.6%	348,047	0.7%	5.1%	0.1%	$35,698	0.6%	$21,460	1.3%	$34,035	0.4%
Long-Term Forecast														
2015	658,196	0.9%	339,543	0.5%	359,481	0.6%	5.1%	0.0%	$37,067	0.8%	$22,835	1.2%	$34,694	0.4%
2020	687,092	0.9%	351,837	0.7%	374,974	0.8%	5.0%	-0.1%	$37,958	0.5%	$24,453	1.4%	$35,589	0.5%
2025	720,299	0.9%	365,821	0.8%	392,596	0.9%	5.0%	0.0%	$38,811	0.4%	$26,182	1.4%	$36,349	0.4%
2030	754,558	0.9%	379,361	0.7%	409,658	0.9%	5.0%	0.0%	$39,647	0.4%	$28,061	1.4%	$37,188	0.5%

Notes: Wages & Per Capita Income are in constant 2006 dollars; Income is in millions of constant 2005 dollars. Growth rates are average annual changes. Data for 2004 and 2005 are simulated.

Table 4-9

Northern Economic Region History and Forecast
Regional Summary

	Population	(%) Change	Labor Force	(%) Change	Total Employment	(%) Change	Unemployment Rate	(%) Change	Average Real Wages	(%) Change	Regional Income	(%) Change	Real Per Capita Income	(%) Change
Actual														
1990	344,103	1.5%	180,392	5.5%	115,497	5.0%	3.5%	-22.5%	$26,440	0.4%	$8,399	1.4%	$24,408	-0.1%
1991	349,452	1.6%	178,882	-0.8%	121,671	5.3%	5.5%	58.0%	$26,220	-0.8%	$8,529	1.5%	$24,406	0.0%
1992	354,500	1.4%	180,957	1.2%	125,506	3.2%	6.2%	13.3%	$27,263	4.0%	$8,862	3.9%	$24,999	2.4%
1993	360,691	1.7%	183,490	1.4%	129,937	3.5%	5.3%	-13.8%	$27,707	1.6%	$9,000	1.6%	$24,953	-0.2%
1994	365,753	1.4%	186,113	1.4%	140,633	8.2%	4.7%	-12.2%	$28,509	2.9%	$9,333	3.7%	$25,517	2.3%
1995	371,503	1.6%	190,613	2.4%	154,575	9.9%	4.4%	-5.3%	$30,216	6.0%	$9,583	2.7%	$25,794	1.1%
1996	376,514	1.3%	191,975	0.7%	161,794	4.7%	4.4%	0.0%	$30,854	2.1%	$10,037	4.7%	$26,658	3.4%
1997	383,404	1.8%	199,678	4.0%	169,420	4.7%	4.1%	-8.5%	$31,703	2.8%	$10,556	5.2%	$27,531	3.3%
1998	389,397	1.6%	202,205	1.3%	177,753	4.9%	3.4%	-16.0%	$32,074	1.2%	$11,097	5.1%	$28,497	3.5%
1999	395,346	1.5%	206,458	2.1%	188,376	6.0%	3.2%	-5.9%	$33,044	3.0%	$11,539	4.0%	$29,188	2.4%
2000	401,277	1.5%	211,827	2.6%	192,238	2.1%	3.3%	1.6%	$33,770	2.2%	$12,234	6.0%	$30,488	4.5%
2001	405,841	1.1%	212,557	0.3%	190,683	-0.8%	4.9%	49.2%	$35,313	4.6%	$11,802	-3.5%	$29,079	-4.6%
2002	409,667	0.9%	207,582	-2.3%	191,687	0.5%	4.5%	-7.2%	$35,534	0.6%	$12,219	3.5%	$29,827	2.6%
2003	414,374	1.1%	220,466	6.2%	194,727	1.6%	5.1%	13.9%	$36,046	1.4%	$12,435	1.8%	$30,008	0.6%
2004	419,764	1.3%	215,867	-2.1%	196,696	1.0%	5.0%	-2.1%	$36,137	0.3%	$12,617	1.5%	$30,057	0.2%
2005	425,151	1.3%	218,409	1.2%	202,718	3.1%	5.4%	7.3%	$36,615	1.3%	$12,930	2.5%	$30,414	1.2%
Forecast														
2006	430,665	1.3%	220,444	0.9%	207,540	2.4%	5.3%	-0.8%	$36,137	-1.3%	$13,220	2.2%	$30,697	0.9%
2007	436,265	1.3%	222,258	0.8%	211,838	2.1%	5.4%	0.8%	$36,615	1.3%	$13,478	2.0%	$30,894	0.6%
2008	441,922	1.3%	224,216	0.9%	216,475	2.2%	5.3%	-1.3%	$36,980	1.0%	$13,741	2.0%	$31,095	0.6%
2009	447,618	1.3%	225,891	0.7%	220,443	1.8%	5.2%	-1.9%	$37,280	0.8%	$13,987	1.8%	$31,247	0.5%
2010	453,340	1.3%	227,348	0.6%	223,895	1.6%	5.2%	-0.1%	$37,555	0.7%	$14,249	1.9%	$31,431	0.6%
Long-Term Forecast														
2015	482,121	1.2%	232,293	0.4%	235,610	1.0%	5.0%	-0.9%	$39,227	0.9%	$15,456	1.6%	$32,058	0.4%
2020	510,983	1.2%	238,790	0.6%	251,000	1.3%	4.8%	-0.6%	$40,372	0.6%	$16,892	1.8%	$33,057	0.6%
2025	539,857	1.1%	245,575	0.6%	267,074	1.2%	4.8%	0.0%	$41,437	0.5%	$18,502	1.8%	$34,271	0.7%
2030	568,732	1.0%	251,684	0.5%	281,545	1.1%	4.8%	-0.3%	$42,455	0.5%	$20,231	1.8%	$35,571	0.7%

Notes: ***Wages & Per Capita Income are in constant 2006 dollars; Income is in millions of constant 2005 dollars.***
Growth rates are average annual changes. Data for 2004 and 2005 are simulated.

SECTION 5.0

RESIDENTIAL CUSTOMER FORECAST

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Section 5.0
Residential Customer Forecast

5.1 Introduction

Nearly 60 percent of EKPC's member system retail sales are to the residential class, therefore, the forecast of residential customers has a large impact on the overall load forecast. It is developed as follows:

1. Forecasts of regional households are prepared by modeling population growth and changes in household size.

2. Within each geographic region, there are many utilities that serve those customers. The portion of those customers that the member system serves is modeled in a 'share' variable. Historical values of share are calculated from data provided by the member systems. Forecasts of share are made based on historical trends and knowledge about service area development.

3. The population and household variables are combined with the share variable to represent the growth for a specific member system instead of the entire economic region.

$$\text{Population Share} = (\text{Regional Population} * \text{Share})$$

$$\text{Regional Households} = \frac{\text{Regional Population}}{\text{People Per Household}}$$

$$\text{Household Share} = (\text{Regional Households} * \text{Share})$$

These variables are used in a regression equation to produce a forecast of residential customers for each member system. Other economic variables from EKPC's Regional Economic Model, such as total employment, or household income, may be used in the equations where appropriate.

4. The variables in the previous equations and their sources are listed below:

Variable	Historical Source	Forecast Source
Population	Bureau of Economic Analysis	EKPC Regional Model
Household Size	Census Bureau	Trend Growth
Share-The percent of regional households served by Member Systems	RUS Form 7	Trend Growth

5. The EKPC system residential customer forecast is the summation of the 16 member system forecasts, 17 beginning in 2008 with the addition of Warren RECC as a member.

5.2 Residential Customer Forecast Results

The average number of residential customers served by EKPC is expected to increase from a total of 458,000 in 2005 to 719,000 in 2026. While population growth is projected to increase at lower levels than historical trends, member systems are expected to receive an increasing share of regional growth and development. Overall customer changes are projected to grow at slower rates in the future. A summary of the system residential customer projections is shown in Figure 5-1 and Table 5-1. Individual member system customer forecasts are reported in Appendix A. Model specifics are provided in Appendix B.

Figure 5-1

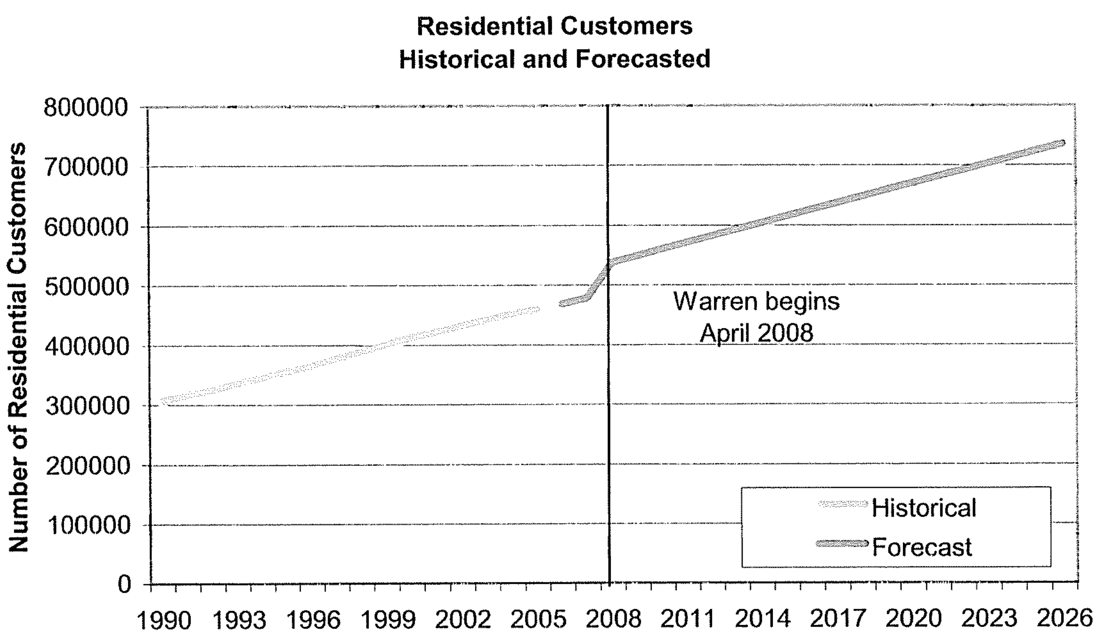

Table 5-1
Residential Class
Customer History and Forecast

Year	Annual Average	Annual Change	% Change
1990	306,458		
1991	314,536	8,077	2.6%
1992	323,980	9,445	3.0%
1993	334,794	10,813	3.3%
1994	344,264	9,470	2.8%
1995	354,308	10,044	2.9%
1996	364,497	10,190	2.9%
1997	376,022	11,525	3.2%
1998	387,968	11,946	3.2%
1999	399,830	11,862	3.1%
2000	411,670	11,839	3.0%
2001	421,099	9,429	2.3%
2002	431,607	10,509	2.5%
2003	441,331	9,724	2.3%
2004	451,340	10,009	2.3%
2005	458,224	6,884	1.5%
2006	467,468	9,244	2.0%
2007	477,298	9,830	2.1%
2008	536,738	59,441	12.5%
2009	547,663	10,924	2.0%
2010	558,636	10,973	2.0%
2011	569,555	10,919	2.0%
2012	580,588	11,033	1.9%
2013	591,587	11,000	1.9%
2014	602,563	10,976	1.9%
2015	613,560	10,997	1.8%
2016	624,530	10,970	1.8%
2017	635,513	10,982	1.8%
2018	646,509	10,996	1.7%
2019	657,479	10,970	1.7%
2020	668,470	10,991	1.7%
2021	679,451	10,982	1.6%
2022	690,431	10,979	1.6%
2023	701,403	10,973	1.6%
2024	712,339	10,935	1.6%
2025	723,242	10,903	1.5%
2026	734,145	10,903	1.5%

Note: Warren RECC begins April 2008

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SECTION 6.0

RESIDENTIAL SALES FORECAST

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Section 6.0
Residential Sales Forecast

6.1 Methodology

EKPC uses statistically adjusted end-use (SAE) models to forecast residential sales. This method of modeling incorporates end-use forecasts in the background and can be used to decompose the monthly and annual forecasts into end-use components. SAE models offer the structure of end-use models while also utilizing the strength of time-series analysis.

This method, like end-use modeling, requires detailed information about appliance saturation, appliance use, appliance efficiencies, household characteristics, weather characteristics, and demographic and economic information. The SAE approach segments the average household use into end-use components as follows:

$$Use_{y,m} = Heat_{y,m} + Cool_{y,m} + Water\ Heat_{y,m} + Other_{y,m}$$

Where, y=year
m=month

Each component is defined in terms of its end-use structure. For example, the cool index may be defined as a function of appliance saturation, efficiency of the appliance, and usage of the appliance. Annual end-use indices and a usage variable are constructed and used to develop a variable to be used in least squares regression in the model. These variables are constructed for heating, cooling, water heating, and an 'Other' variable, which includes lighting and other miscellaneous usages.

$$CoolIndex_y = \sum_{Type} Wgt^{Type} * \frac{\left(CoolShare_y^{Type} / Eff_y^{Type} \right)}{\left(CoolShare_{98}^{Type} / Eff_{98}^{Type} \right)}$$

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{NormCDD} \right) * \left(\frac{HHSize_y}{HHSize_{by}} \right) * \left(\frac{Income_y}{Income_{by}} \right) * \left(\frac{Price_{y,m}}{Price_{by}} \right)^{-.30}$$

Where, by=base year

$$\boxed{Cool_{y,m} \quad = \quad CoolIndex_{y} \ * \ CoolUse_{y,m}}$$

The Cool, Heat, Water Heat, and Other variables are then used in a least squares regression which results in estimates for annual and monthly use per household.

Features of EKPC's SAE model are as follows:

1. Twenty years of End-use Survey historical data are used to forecast saturation of appliances.
2. Appliance efficiencies due to government regulation have been accounted for in the model. Indices pertaining to appliance efficiency trends and usage are used to construct energy models based on heating, cooling, water heating and other energy for the residential class. Source: Energy Information Administration Annual Energy Outlook, East South Central region representing Kentucky.
3. Various demographic and socioeconomic factors that affect appliance choice and appliance use are present in the methodology. These include the changing shares of urban and rural customers relative to total customers, number of people living in the household, as well as square footage of the house and the thermal integrity of the house.

Model details of residential sales are provided in Table 6-1. Details by member system are provided in Appendix B.

Table 6-1
Residential Sales Forecast - Appliance Usage Projections

Dependent Variable: Appliance Usage	
Model Inputs	***Source***
Residential Customers	Historical customers are taken from Form 7. Future customers are projected by EKPC and member systems.
Average Real Price of Electricity	Historical price is taken from Form 7. Future prices are projected by EKPC's Pricing Department and member systems.
Appliance Efficiency Improvements and Appliance Lifetimes	Energy Information Administration Annual Energy Outlook
Size of Water Heater	End-Use Survey, Trend Growth
Household Size (People Per Household)	Census Bureau, Trend Growth
Real Household Income	EKPC Regional Model

6.2 Appliance Saturation Projections

Every two years since 1981, EKPC has surveyed the member systems' residential customers. The most recent survey was conducted in 2005. EKPC gathers appliance, insulation, heating and cooling, economic, and demographic data. Appliance holdings of survey respondents are analyzed in order to better understand their electricity consumption and to project future appliance saturations.

EKPC's analysis and forecast of appliance saturations and appliance usage is econometric in nature. The decision made by customers to purchase an appliance can often be understood by examining customer income levels, fuel price, and household characteristics. The choice to purchase an appliance is modeled separately from the decision to use the appliance. This is because these actions are separate and subject to different driving forces.

Residential appliance saturation projections are shown in Table 6-2.

Table 6-2
Appliance Saturations ~ Residential Class

Year	Heat Pump Heating	Electric Furnace	Electric Resistance	Central Air	Heat Pump Cooling	Room Air	Electric Water Heating
1991	14.7%	13.7%	10.8%	25.0%	14.7%	43.0%	85.2%
1992	15.5%	13.9%	10.8%	27.0%	15.5%	42.2%	85.1%
1993	16.3%	13.9%	10.9%	29.0%	16.3%	41.3%	85.0%
1994	16.9%	13.9%	11.0%	28.6%	16.9%	40.1%	86.0%
1995	17.4%	14.0%	11.0%	28.1%	17.4%	38.8%	87.0%
1996	18.6%	14.1%	10.7%	29.8%	18.6%	37.1%	86.8%
1997	20.0%	14.2%	10.5%	31.5%	20.0%	35.5%	86.5%
1998	21.4%	14.3%	10.4%	33.4%	21.4%	34.1%	86.3%
1999	22.4%	14.5%	10.2%	35.3%	22.4%	32.7%	85.9%
2000	23.4%	14.6%	10.0%	37.3%	23.4%	31.2%	85.5%
2001	24.7%	14.8%	9.6%	39.4%	24.7%	29.8%	85.1%
2002	26.0%	14.9%	9.3%	39.8%	26.0%	28.4%	85.7%
2003	27.3%	15.4%	8.9%	40.1%	27.3%	27.0%	86.3%
2004	28.6%	15.9%	8.5%	40.2%	28.6%	25.5%	86.9%
2005	29.7%	16.4%	8.4%	41.9%	29.7%	24.2%	87.0%
2006	29.9%	16.6%	8.4%	42.0%	29.9%	23.8%	87.0%
2007	30.0%	16.9%	8.3%	42.1%	30.0%	23.4%	86.9%
2008	30.2%	17.2%	8.3%	42.2%	30.2%	23.1%	86.8%
2009	30.4%	17.5%	8.3%	42.3%	30.4%	22.7%	86.7%
2010	30.6%	17.7%	8.2%	42.4%	30.6%	22.3%	86.7%
2011	30.7%	18.0%	8.2%	42.5%	30.7%	21.9%	86.6%
2012	30.9%	18.3%	8.2%	42.6%	30.9%	21.6%	86.5%
2013	31.1%	18.6%	8.2%	42.7%	31.1%	21.2%	86.4%
2014	31.3%	18.8%	8.1%	42.8%	31.3%	20.8%	86.4%
2015	31.4%	19.1%	8.1%	42.9%	31.4%	20.4%	86.3%
2016	31.6%	19.4%	8.1%	43.0%	31.6%	20.1%	86.2%
2017	31.8%	19.7%	8.1%	43.1%	31.8%	19.7%	86.1%
2018	32.0%	19.9%	8.0%	43.2%	32.0%	19.3%	86.1%
2019	32.1%	20.2%	8.0%	43.3%	32.1%	18.9%	86.0%
2020	32.3%	20.5%	8.0%	43.4%	32.3%	18.6%	85.9%
2021	32.5%	20.8%	7.9%	43.5%	32.5%	18.2%	85.8%
2022	32.7%	21.0%	7.9%	43.6%	32.7%	17.8%	85.8%
2023	32.8%	21.3%	7.9%	43.7%	32.8%	17.4%	85.7%
2024	33.0%	21.6%	7.9%	43.8%	33.0%	17.1%	85.6%
2025	33.2%	21.9%	7.8%	43.9%	33.2%	16.7%	85.5%
2026	33.4%	22.1%	7.8%	44.0%	33.4%	16.3%	85.5%

Table 6-2 Continued
Appliance Saturations ~ Residential Class

Year	Automatic Defrost Refrigerator	Freezer	Clothes Washer	Electric Clothes Dryer	Electric Range	Color TV	Microwave	Water Pump	Dishwasher
1991	73.4%	61.1%	81.4%	69.3%	80.1%	103.0%	73.6%	28.3%	22.2%
1992	79.6%	62.9%	82.2%	72.7%	82.4%	116.0%	78.2%	27.6%	24.6%
1993	85.7%	64.6%	83.0%	76.1%	84.7%	128.9%	82.8%	26.9%	27.0%
1994	89.0%	63.7%	84.9%	75.5%	85.4%	134.2%	75.5%	23.4%	23.5%
1995	92.2%	62.8%	86.7%	74.9%	86.1%	139.5%	68.2%	22.7%	20.0%
1996	92.3%	61.7%	89.5%	78.7%	86.1%	145.5%	71.4%	22.0%	21.8%
1997	92.4%	60.5%	92.4%	82.4%	86.1%	151.5%	74.6%	21.3%	23.6%
1998	94.6%	60.8%	92.8%	83.9%	86.5%	156.0%	77.2%	20.9%	27.9%
1999	96.9%	61.0%	93.2%	85.3%	86.9%	160.4%	79.9%	20.5%	32.2%
2000	99.2%	61.3%	93.6%	86.7%	87.3%	164.8%	82.6%	20.1%	36.5%
2001	101.5%	61.5%	94.0%	88.2%	87.7%	169.2%	85.3%	19.7%	40.7%
2002	103.8%	61.8%	94.3%	89.6%	88.1%	173.7%	88.0%	19.3%	45.0%
2003	106.1%	62.0%	94.7%	91.0%	88.5%	178.1%	90.6%	18.9%	49.3%
2004	108.4%	62.3%	95.1%	92.4%	88.8%	182.5%	93.3%	18.5%	53.6%
2005	109.1%	62.8%	95.2%	94.8%	89.6%	183.7%	94.2%	18.1%	55.2%
2006	109.2%	62.9%	95.3%	94.8%	89.7%	184.7%	94.3%	17.8%	55.5%
2007	109.4%	63.1%	95.3%	94.9%	89.7%	185.7%	94.3%	17.6%	55.8%
2008	109.5%	63.2%	95.4%	94.9%	89.8%	186.7%	94.4%	17.3%	56.1%
2009	109.7%	63.4%	95.4%	95.0%	89.8%	187.7%	94.4%	17.1%	56.4%
2010	109.8%	63.5%	95.5%	95.0%	89.9%	188.7%	94.5%	16.8%	56.7%
2011	110.0%	63.7%	95.5%	95.1%	89.9%	189.7%	94.5%	16.6%	57.0%
2012	110.1%	63.8%	95.6%	95.1%	90.0%	190.7%	94.6%	16.3%	57.3%
2013	110.3%	64.0%	95.6%	95.2%	90.0%	191.7%	94.6%	16.1%	57.6%
2014	110.4%	64.1%	95.6%	95.2%	90.1%	192.7%	94.7%	15.8%	57.9%
2015	110.6%	64.3%	95.7%	95.3%	90.1%	193.7%	94.7%	15.6%	58.2%
2016	110.7%	64.4%	95.7%	95.3%	90.2%	194.7%	94.8%	15.3%	58.5%
2017	110.9%	64.6%	95.8%	95.4%	90.2%	195.7%	94.8%	15.1%	58.8%
2018	111.0%	64.7%	95.8%	95.4%	90.3%	196.7%	94.9%	14.8%	59.1%
2019	111.2%	64.9%	95.9%	95.5%	90.3%	197.7%	94.9%	14.6%	59.4%
2020	111.3%	65.0%	95.9%	95.5%	90.4%	198.7%	95.0%	14.3%	59.7%
2021	111.5%	65.2%	96.0%	95.6%	90.4%	199.7%	95.0%	14.1%	60.0%
2022	111.6%	65.3%	96.0%	95.6%	90.5%	200.7%	95.1%	13.8%	60.3%
2023	111.8%	65.5%	96.1%	95.7%	90.5%	201.7%	95.1%	13.6%	60.6%
2024	111.9%	65.6%	96.1%	95.7%	90.6%	202.7%	95.2%	13.3%	60.9%
2025	112.1%	65.8%	96.2%	95.8%	90.6%	203.7%	95.2%	13.1%	61.2%
2026	112.2%	65.9%	96.2%	95.8%	90.7%	204.7%	95.3%	12.8%	61.5%

6.3 Residential Class Sales Forecast Results

Sales to the Residential Class are expected to grow 2.9% over the next 20 years. Electric use per customer is continuing to grow modestly, however, the projection is more modest than in the 2004 forecast. Increasing house size is contributing to the increase, as well as more appliances in each home. The End-Use Survey supports this assumption. The result is larger heating and cooling requirements. However, efficiency improvements in appliances and in housing construction tend to dampen consumption levels. The forecast of residential sales is impacted by large improvements in appliance efficiency. By 2026, EKPC projects residential retail sales to have been reduced by nearly 1,200,000 MWh, due primarily to more efficient refrigerators, freezers, and air conditioning.

Figure 6-1 illustrates the monthly use per customer trend. Table 6-3 reports historical and projected use per customer and class sales.

Figure 6-1
Average Monthly Use Per Customer
Residential Class

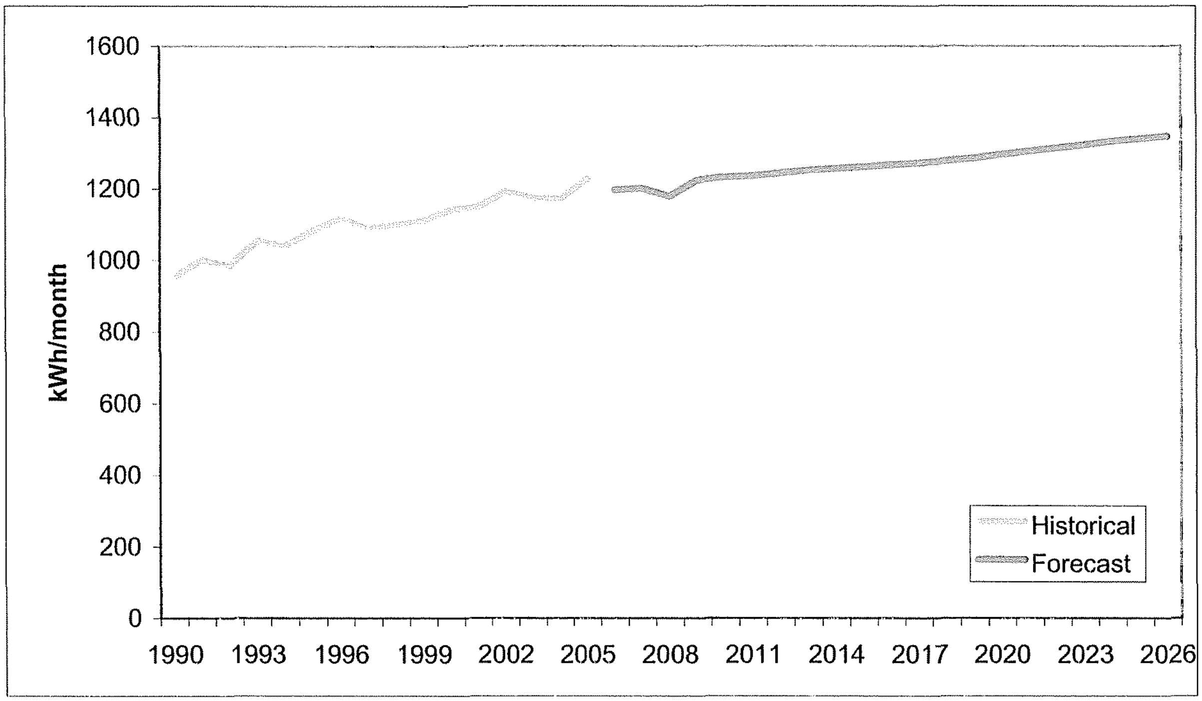


Table 6-3
Residential Class
Customers and Sales

	Customers			*Use Per Customer*			*Class Sales*		
	Annual Average	Annual Change	% Change	Monthly Average (kWh)	Annual Change (kWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
1990	306,458			951			3,495,899		
1991	314,536	8,077	2.6	999	48	5.0	3,769,089	273,189	7.8
1992	323,980	9,445	3.0	980	-18	-1.8	3,811,817	42,729	1.1
1993	334,794	10,813	3.3	1,053	72	7.4	4,228,581	416,763	10.9
1994	344,264	9,470	2.8	1,037	-16	-1.5	4,283,267	54,687	1.3
1995	354,308	10,044	2.9	1,080	43	4.1	4,591,084	307,817	7.2
1996	364,497	10,190	2.9	1,114	34	3.2	4,873,716	282,632	6.2
1997	376,022	11,525	3.2	1,086	-29	-2.6	4,899,179	25,463	0.5
1998	387,968	11,946	3.2	1,097	11	1.0	5,107,125	207,947	4.2
1999	399,830	11,862	3.1	1,109	12	1.1	5,318,860	211,735	4.1
2000	411,670	11,839	3.0	1,139	30	2.7	5,624,384	305,524	5.7
2001	421,099	9,429	2.3	1,147	8	0.7	5,795,728	171,344	3.0
2002	431,607	10,509	2.5	1,190	43	3.8	6,164,400	368,672	6.4
2003	441,331	9,724	2.3	1,171	-19	-1.6	6,203,143	38,743	0.6
2004	451,340	10,009	2.3	1,170	-2	-0.1	6,335,445	132,302	2.1
2005	458,224	6,884	1.5	1,226	57	4.8	6,743,486	408,040	6.4
2006	467,468	9,244	2.0	1,195	-32	-2.6	6,702,645	-40,841	-0.6
2007	477,298	9,830	2.1	1,199	4	0.3	6,865,831	163,186	2.4
2008	536,738	59,441	12.5	1,176	-22	-1.9	7,576,749	710,918	10.4
2009	547,663	10,924	2.0	1,223	46	4.0	8,036,352	459,603	6.1
2010	558,636	10,973	2.0	1,230	7	0.6	8,246,901	210,549	2.6
2011	569,555	10,919	2.0	1,234	4	0.3	8,432,930	186,029	2.3
2012	580,588	11,033	1.9	1,242	8	0.6	8,650,448	217,518	2.6
2013	591,587	11,000	1.9	1,249	8	0.6	8,868,278	217,830	2.5
2014	602,563	10,976	1.9	1,254	5	0.4	9,069,536	201,259	2.3
2015	613,560	10,997	1.8	1,259	5	0.4	9,270,396	200,859	2.2
2016	624,530	10,970	1.8	1,265	6	0.5	9,479,347	208,951	2.3
2017	635,513	10,982	1.8	1,269	5	0.4	9,681,304	201,957	2.1
2018	646,509	10,996	1.7	1,276	7	0.5	9,900,800	219,496	2.3
2019	657,479	10,970	1.7	1,283	7	0.5	10,120,469	219,669	2.2
2020	668,470	10,991	1.7	1,293	10	0.8	10,371,328	250,859	2.5
2021	679,451	10,982	1.6	1,303	10	0.8	10,624,237	252,909	2.4
2022	690,431	10,979	1.6	1,312	9	0.7	10,867,695	243,457	2.3
2023	701,403	10,973	1.6	1,320	9	0.7	11,112,981	245,286	2.3
2024	712,339	10,935	1.6	1,330	10	0.8	11,371,259	258,278	2.3
2025	723,242	10,903	1.5	1,337	7	0.5	11,605,707	234,448	2.1
2026	734,145	10,903	1.5	1,344	7	0.5	11,840,688	234,981	2.0

SECTION 7.0

COMMERCIAL AND OTHER SALES FORECAST

Section 7.0
Commercial and Other Sales Forecast

7.1 Small Commercial Sales Forecast

Member system cooperatives classify commercial and industrial accounts into two groups. Customers whose annual peak demand is less than 1 MW are classified as small commercial customers and customers whose annual peak demand is greater than or equal to 1 MW are classified as large commercial customers. Most commercial customers are accounted for in the small commercial classification. In 2005, there were over 30,000 small commercial customers on the system.

EKPC projects class sales by member system through regression analysis of historical data. Typical regressions include small commercial customers as a function of residential customers, unemployment rate, and other economic variables. The sales regression usually includes customers, electric price, and other economic measures as explanatory variables. Historical and projected small commercial sales for EKPC are reported in Table 7-1. Member system regression equations are in Appendix B.

7.2 Large Commercial Sales Forecast

In 2005, there were 139 retail customers classified as large commercial customers. The total annual usage was greater than the annual usage of the small commercial class. The overall importance of the Large Commercial Class cannot be overemphasized, as this class has experienced substantial growth since 1995. Approximately half of EKPC's large commercial customers are manufacturing plants.

The Large Commercial Class is forecasted using input from member systems as well as a modeling approach. New industrial customers that member systems expect in the next few years are explicitly input into the models. To estimate total new large loads at the system level, a regression approach is used. A probabilistic model is then used to distribute these customers among the 16 member systems. A prototype load of 1.5 MW and 60% load factor is assumed for these new loads. This methodology for forecasting new large commercial customers and energy provides a robust and defensible projection at the member system level as well as the system level. Table 7-2 reports historical and projected large commercial customers and sales.

Member systems are in regular contact with large commercial customers in order to remain current with production and facility expansion plans. Member systems communicate with local industrial development groups, which keeps them aware of the status of new large commercial customers. EKPC has a program of industrial recruiting, and promotes industrial sites that are within member systems' service areas. EKPC and its members are working hard to contribute to local efforts to attract industry.

7.3 Seasonal Sales Forecast

Seasonal sales are sales to customers with seasonal residences such as vacation and weekend homes. Seasonal sales are relatively small and are reported by only one of EKPC's member systems. Table 7-3 reports historical and projected seasonal sales for EKPC.

7.4 Public Building Sales Forecast

Public Building sales include sales to accounts such as government buildings and libraries. The sales are relatively small and are reported by only two of EKPC's member systems. Table 7-4 reports historical and projected public building sales for EKPC.

7.5 Other Sales Forecast

Other retail sales refer mainly to street lighting. Table 7-5 reports historical and projected retail sales for this class. This class is reported by 11 member systems.

Table 7-1
Historical and Projected Small Commercial Customers and Sales

	Annual Average	Annual Change	% Change	Annual Average (MWh)	Annual Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
1990	22,169			37			813,371		
1991	17,512	-4,656	-21.0	50	13	35.1	868,031	54,660	6.7
1992	18,055	542	3.1	51	1	2.1	913,599	45,567	5.2
1993	18,561	507	2.8	53	2	4.4	980,301	66,702	7.3
1994	19,092	531	2.9	53	0	0.6	1,014,549	34,248	3.5
1995	19,669	576	3.0	56	3	5.0	1,097,729	83,180	8.2
1996	20,399	731	3.7	56	0	0.0	1,138,469	40,740	3.7
1997	21,084	685	3.4	55	-1	-1.1	1,163,683	25,214	2.2
1998	21,834	750	3.6	56	1	2.1	1,230,450	66,767	5.7
1999	22,813	979	4.5	59	2	4.0	1,336,957	106,506	8.7
2000	23,730	918	4.0	61	2	4.0	1,446,958	110,001	8.2
2001	25,129	1,399	5.9	60	-1	-1.7	1,505,480	58,522	4.0
2002	26,340	1,211	4.8	60	0	0.0	1,577,590	72,110	4.8
2003	26,661	320	1.2	58	-2	-2.9	1,550,248	-27,342	-1.7
2004	28,125	1,464	5.5	57	-1	-2.3	1,598,111	47,864	3.1
2005	30,613	2,488	8.8	57	0	-0.4	1,733,280	135,169	8.5
2006	29,717	-896	-2.9	60	3	5.8	1,780,456	47,176	2.7
2007	30,471	753	2.5	61	1	1.0	1,844,468	64,011	3.6
2008	40,792	10,321	33.9	53	-8	-13.2	2,143,068	298,600	16.2
2009	41,776	984	2.4	54	2	3.5	2,271,045	127,977	6.0
2010	42,756	980	2.3	55	0	0.3	2,330,473	59,428	2.6
2011	43,731	974	2.3	55	0	0.2	2,387,349	56,876	2.4
2012	44,703	973	2.2	55	0	0.1	2,443,562	56,213	2.4
2013	45,675	972	2.2	55	0	0.1	2,499,753	56,191	2.3
2014	46,648	973	2.1	55	0	0.1	2,555,818	56,065	2.2
2015	47,623	975	2.1	55	0	0.1	2,612,249	56,431	2.2
2016	48,599	975	2.0	55	0	0.1	2,669,288	57,039	2.2
2017	49,575	976	2.0	55	0	0.2	2,727,493	58,205	2.2
2018	50,556	981	2.0	55	0	0.2	2,786,650	59,157	2.2
2019	51,539	983	1.9	55	0	0.2	2,846,226	59,576	2.1
2020	52,520	981	1.9	55	0	0.2	2,905,708	59,483	2.1
2021	53,502	982	1.9	55	0	0.2	2,965,803	60,095	2.1
2022	54,483	981	1.8	56	0	0.2	3,025,759	59,956	2.0
2023	55,463	979	1.8	56	0	0.2	3,085,307	59,548	2.0
2024	56,440	977	1.8	56	0	0.2	3,144,693	59,386	1.9
2025	57,413	974	1.7	56	0	0.1	3,203,587	58,894	1.9
2026	58,387	974	1.7	56	0	0.1	3,262,188	58,601	1.8

Note: Warren begins April 2008

Table 7-2
Historical and Projected Large Commercial Customers and Sales

	Annual Average	Annual Change	% Change	Annual Average (MWh)	Annual Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
1990	59			11,139			653,502		
1991	66	7	12.5	10,991	-148	-1.3	725,419	71,917	11.0
1992	64	-2	-2.5	12,066	1,075	9.8	776,268	50,848	7.0
1993	68	3	4.9	14,346	2,280	18.9	968,345	192,078	24.7
1994	72	4	6.3	14,313	-33	-0.2	1,026,927	58,582	6.0
1995	71	-1	-1.6	15,859	1,546	10.8	1,119,361	92,435	9.0
1996	78	8	10.9	15,192	-667	-4.2	1,188,760	69,398	6.2
1997	86	8	9.8	14,628	-563	-3.7	1,256,829	68,069	5.7
1998	95	9	10.4	14,192	-437	-3.0	1,345,859	89,031	7.1
1999	101	6	6.1	14,069	-123	-0.9	1,415,128	69,269	5.1
2000	103	3	2.6	14,574	505	3.6	1,503,523	88,395	6.2
2001	112	8	8.1	14,943	369	2.5	1,666,141	162,618	10.8
2002	111	-1	-0.4	16,201	1,258	8.4	1,798,352	132,211	7.9
2003	133	22	19.4	14,135	-2,067	-12.8	1,874,044	75,692	4.2
2004	136	4	2.6	14,622	487	3.4	1,989,780	115,736	6.2
2005	139	3	2.2	14,530	-91	-0.6	2,020,930	31,150	1.6
2006	140	1	0.5	15,144	614	4.2	2,116,434	95,503	4.7
2007	152	12	8.4	14,901	-243	-1.6	2,257,560	141,126	6.7
2008	217	66	43.2	13,491	-1,411	-9.5	2,927,518	669,958	29.7
2009	224	7	3.2	14,231	740	5.5	3,187,814	260,297	8.9
2010	232	8	3.6	14,230	-1	0.0	3,301,354	113,540	3.6
2011	238	6	2.6	14,270	40	0.3	3,396,327	94,973	2.9
2012	241	3	1.3	14,414	144	1.0	3,473,788	77,461	2.3
2013	244	3	1.2	14,551	137	0.9	3,550,403	76,615	2.2
2014	247	3	1.2	14,680	129	0.9	3,625,976	75,573	2.1
2015	250	3	1.2	14,804	123	0.8	3,700,886	74,911	2.1
2016	255	5	2.0	14,872	68	0.5	3,792,252	91,366	2.5
2017	259	4	1.6	14,965	93	0.6	3,875,814	83,562	2.2
2018	262	3	1.2	15,083	118	0.8	3,951,703	75,889	2.0
2019	268	6	2.3	15,120	37	0.2	4,052,080	100,378	2.5
2020	273	5	1.9	15,179	59	0.4	4,143,897	91,817	2.3
2021	277	4	1.5	15,260	81	0.5	4,227,112	83,215	2.0
2022	282	5	1.8	15,312	51	0.3	4,317,896	90,784	2.1
2023	286	4	1.4	15,384	73	0.5	4,399,917	82,021	1.9
2024	289	3	1.0	15,478	93	0.6	4,473,032	73,115	1.7
2025	293	4	1.4	15,542	64	0.4	4,553,769	80,737	1.8
2026	297	4	1.4	15,547	5	0.0	4,617,527	63,758	1.4

Note: Warren begins April 2008

Table 7-3
Historical and Projected Seasonal Customers and Sales

	Annual Average	Annual Change	% Change	Monthly Average (kWh)	Annual Change (kWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
1990	3,020			251			9,094		
1991	3,133	113	3.7	251	0	-0.1	9,423	329	3.6
1992	3,288	156	5.0	247	-3	-1.4	9,756	333	3.5
1993	2,693	-596	-18.1	314	67	27.0	10,144	389	4.0
1994	2,817	124	4.6	304	-10	-3.1	10,280	136	1.3
1995	2,936	120	4.2	314	10	3.3	11,066	786	7.6
1996	3,119	183	6.2	330	16	5.0	12,342	1,276	11.5
1997	2,996	-123	-4.0	331	1	0.3	11,888	-454	-3.7
1998	3,417	421	14.0	280	-51	-15.4	11,476	-412	-3.5
1999	3,563	146	4.3	269	-11	-3.9	11,496	20	0.2
2000	3,713	151	4.2	280	11	4.2	12,479	983	8.6
2001	3,799	85	2.3	280	0	0.0	12,769	290	2.3
2002	3,956	157	4.1	297	16	5.8	14,076	1,307	10.2
2003	4,046	90	2.3	277	-20	-6.6	13,445	-631	-4.5
2004	4,162	116	2.9	277	0	0.1	13,846	402	3.0
2005	4,297	135	3.2	281	4	1.4	14,501	655	4.7
2006	4,412	115	2.7	273	-8	-3.0	14,445	-56	-0.4
2007	4,514	102	2.3	276	3	1.1	14,945	500	3.5
2008	4,616	102	2.3	279	3	1.2	15,470	525	3.5
2009	4,718	102	2.2	283	3	1.2	16,009	539	3.5
2010	4,821	103	2.2	285	2	0.8	16,493	484	3.0
2011	4,924	103	2.1	286	1	0.4	16,911	418	2.5
2012	5,028	104	2.1	289	3	1.2	17,466	555	3.3
2013	5,132	104	2.1	293	3	1.1	18,016	550	3.2
2014	5,236	104	2.0	295	2	0.8	18,535	519	2.9
2015	5,341	105	2.0	297	2	0.8	19,050	515	2.8
2016	5,446	105	2.0	300	3	0.9	19,593	543	2.9
2017	5,552	106	1.9	302	2	0.6	20,098	504	2.6
2018	5,658	106	1.9	304	2	0.8	20,637	539	2.7
2019	5,764	106	1.9	307	3	0.9	21,220	583	2.8
2020	5,871	107	1.9	311	4	1.2	21,880	660	3.1
2021	5,978	107	1.8	314	3	1.1	22,524	644	2.9
2022	6,086	108	1.8	317	3	1.1	23,173	648	2.9
2023	6,194	108	1.8	321	3	1.0	23,824	651	2.8
2024	6,302	108	1.7	324	4	1.1	24,512	689	2.9
2025	6,411	109	1.7	326	2	0.7	25,103	590	2.4
2026	6,520	109	1.7	329	3	0.9	25,765	662	2.6

Note: Warren begins April 2008

Table 7-4
Historical and Projected Public Buildings Customers and Sales

	Annual Average	Annual Change	% Change	Monthly Average (kWh)	Annual Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
1990	897			1,000			10,770		
1991	913	16	1.8	1,072	72	7.2	11,744	974	9.0
1992	926	13	1.4	1,201	130	12.1	13,345	1,601	13.6
1993	979	54	5.8	1,334	133	11.1	15,684	2,339	17.5
1994	995	15	1.5	1,347	12	0.9	16,073	389	2.5
1995	1,016	22	2.2	1,453	106	7.9	17,715	1,642	10.2
1996	1,022	6	0.6	1,527	75	5.1	18,732	1,017	5.7
1997	1,040	18	1.7	1,455	-72	-4.7	18,151	-580	-3.1
1998	1,069	29	2.8	1,497	42	2.9	19,191	1,040	5.7
1999	1,077	9	0.8	1,529	32	2.1	19,763	572	3.0
2000	1,093	16	1.5	1,555	26	1.7	20,397	634	3.2
2001	1,120	27	2.5	1,564	10	0.6	21,032	635	3.1
2002	1,144	23	2.1	1,660	95	6.1	22,776	1,744	8.3
2003	1,165	22	1.9	1,715	55	3.3	23,975	1,199	5.3
2004	1,177	12	1.0	1,789	74	4.3	25,266	1,291	5.4
2005	1,173	-4	-0.3	1,781	-8	-0.5	25,065	-200	-0.8
2006	1,185	12	1.0	1,771	-10	-0.5	25,185	120	0.5
2007	1,198	13	1.1	1,800	29	1.6	25,880	694	2.8
2008	1,210	12	1.0	1,830	30	1.7	26,578	698	2.7
2009	1,221	11	0.9	1,865	35	1.9	27,330	753	2.8
2010	1,232	11	0.9	1,896	30	1.6	28,023	693	2.5
2011	1,242	10	0.8	1,924	28	1.5	28,674	651	2.3
2012	1,254	12	1.0	1,952	28	1.5	29,377	703	2.5
2013	1,265	11	0.9	1,984	32	1.6	30,115	738	2.5
2014	1,276	11	0.9	2,012	29	1.4	30,813	699	2.3
2015	1,286	10	0.8	2,041	28	1.4	31,491	677	2.2
2016	1,296	10	0.8	2,069	28	1.4	32,174	683	2.2
2017	1,308	12	0.9	2,094	25	1.2	32,868	694	2.2
2018	1,319	11	0.8	2,121	27	1.3	33,574	706	2.1
2019	1,329	10	0.8	2,150	29	1.4	34,287	713	2.1
2020	1,340	11	0.8	2,173	23	1.1	34,941	654	1.9
2021	1,350	10	0.7	2,199	26	1.2	35,626	684	2.0
2022	1,360	10	0.7	2,224	25	1.1	36,294	669	1.9
2023	1,371	11	0.8	2,242	18	0.8	36,890	596	1.6
2024	1,381	10	0.7	2,262	20	0.9	37,483	593	1.6
2025	1,391	10	0.7	2,281	19	0.8	38,068	585	1.6
2026	1,401	10	0.7	2,299	18	0.8	38,649	581	1.5

Note: Warren begins April 2008

Table 7-5
Historical and Projected Other Customers and Sales

	Annual Average	Annual Change	% Change	Monthly Average (kWh)	Annual Change (kWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
1990	207			1,504			3,737		
1991	218	11	5.3	1,540	36	2.4	4,029	292	7.8
1992	228	10	4.6	1,573	33	2.1	4,304	275	6.8
1993	252	24	10.5	1,680	107	6.8	5,081	776	18.0
1994	284	32	12.7	1,219	-461	-27.4	4,156	-925	-18.2
1995	347	63	22.2	1,211	-8	-0.7	5,042	887	21.3
1996	417	70	20.2	1,110	-101	-8.3	5,555	513	10.2
1997	395	-22	-5.3	1,195	85	7.6	5,663	108	1.9
1998	296	-99	-25.1	1,577	382	32.0	5,601	-63	-1.1
1999	315	19	6.4	1,524	-53	-3.4	5,756	156	2.8
2000	316	1	0.4	1,624	101	6.6	6,160	404	7.0
2001	330	14	4.3	1,655	30	1.9	6,545	385	6.3
2002	353	24	7.2	1,676	21	1.3	7,107	562	8.6
2003	366	13	3.6	1,696	20	1.2	7,447	340	4.8
2004	377	11	2.9	1,659	-36	-2.1	7,498	51	0.7
2005	389	12	3.2	1,654	-6	-0.3	7,711	212	2.8
2006	398	10	2.5	1,663	9	0.6	7,945	234	3.0
2007	407	9	2.3	1,669	6	0.4	8,157	212	2.7
2008	613	206	50.6	1,677	8	0.5	12,341	4,184	51.3
2009	629	15	2.5	1,825	149	8.9	13,773	1,431	11.6
2010	644	15	2.4	1,827	2	0.1	14,125	352	2.6
2011	660	15	2.4	1,828	1	0.0	14,469	344	2.4
2012	675	15	2.3	1,830	1	0.1	14,817	348	2.4
2013	690	15	2.3	1,830	0	0.0	15,156	339	2.3
2014	706	15	2.2	1,829	0	0.0	15,492	336	2.2
2015	721	15	2.2	1,829	-1	0.0	15,824	332	2.1
2016	736	15	2.1	1,828	-1	0.0	16,155	331	2.1
2017	752	15	2.1	1,827	-1	-0.1	16,484	329	2.0
2018	767	15	2.0	1,827	-1	0.0	16,815	331	2.0
2019	783	15	2.0	1,825	-1	-0.1	17,140	324	1.9
2020	798	15	2.0	1,824	-1	-0.1	17,466	326	1.9
2021	813	15	1.9	1,823	-1	-0.1	17,788	322	1.8
2022	829	15	1.9	1,821	-1	-0.1	18,110	322	1.8
2023	844	15	1.9	1,820	-2	-0.1	18,429	320	1.8
2024	859	15	1.8	1,818	-2	-0.1	18,745	315	1.7
2025	875	15	1.8	1,815	-2	-0.1	19,057	313	1.7
2026	890	15	1.8	1,813	-3	-0.1	19,365	308	1.6

Note: Warren begins April 2008

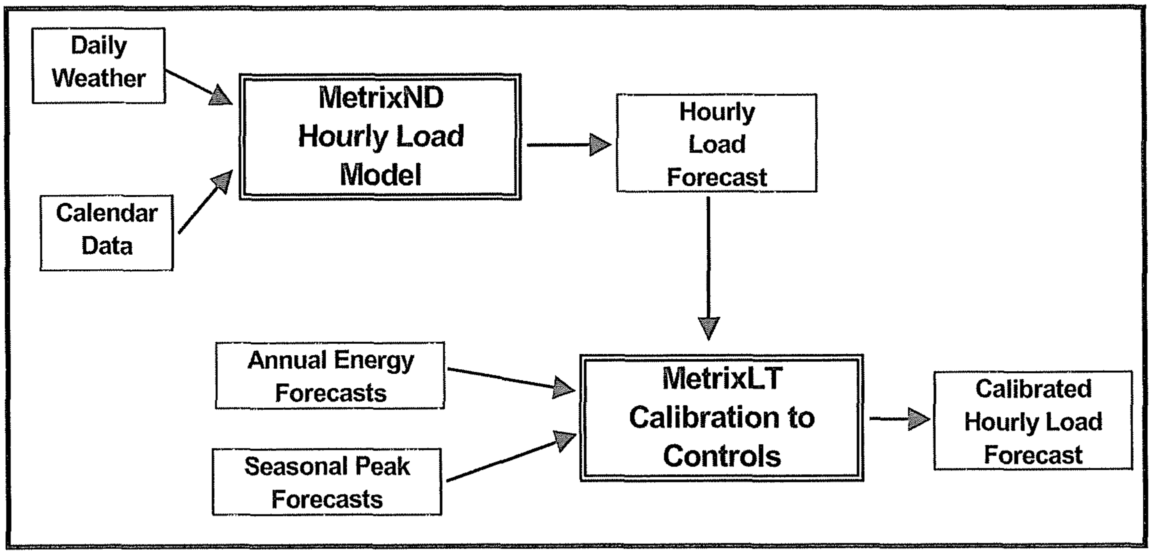
SECTION 8.0

PEAK DEMAND FORECAST
&
HIGH AND LOW CASE SCENARIOS

Section 8.0
Peak Demand Forecast
High and Low Case Scenarios

8.1 Methodology

Prior to 2002, EKPC developed peak demands using end-use load shape data in HELM software. In 2002, EKPC began using Metrix products for forecasting. Now the following process flow is used:



Individual member system forecasts are summed to create an EKPC system forecast. Class energies, as well as winter and summer peak demands, are summed. This is used to create an hourly load model for each of the forecast years. The system load shape is determined from actual historical load data. This hourly load forecast is then calibrated to the seasonal peak demands and annual energy forecasts to build the hourly load forecast for the EKPC system. The software used is Metrix LT from ITRON, formerly RER, Inc.

The data used to forecast seasonal peak demands include:

1. Residential contributions are based on seasonal energy usages for: water heating, air conditioning, heating, and the residual load. Load factors are applied and peak demands are summed to build the class seasonal peak.
2. Small and Large Commercial contributions are based on aggregate class peaks.
3. Normal weather is used for the forecast years.

4. Transmission and distribution losses are accounted for in the model. Table 8-1 shows the historical transmission line losses on the seasonal peak days.

Table 8-1
Historical Transmission Line Losses, Peak Day

Year	Winter Peak Demand, Including Transmission Losses (MW)	Winter Peak Demand, Without Transmission Losses (MW)	Transmission Losses (%)	Summer Peak Demand, Including Transmission Losses (MW)	Summer Peak Demand, Without Transmission Losses (MW)	Transmission Losses (%)
1986	1,039	1,003	3.5	857	817	4.7
1987	983	951	3.3	906	854	5.7
1988	1,104	1,073	2.8	1,055	1,009	4.4
1989	1,114	1,097	1.5	1,010	984	2.6
1990	1,449	1,402	3.2	1,075	1,027	4.5
1991	1,306	1,266	3.1	1,164	1,107	4.9
1992	1,383	1,339	3.2	1,131	1,103	2.5
1993	1,473	1,410	4.3	1,309	1,269	3.1
1994	1,788	1,729	3.3	1,314	1,251	5.0
1995	1,621	1,572	3.1	1,518	1,453	4.5
1996	1,990	1,894	5.1	1,540	1,469	4.8
1997	2,004	1,903	5.3	1,650	1,551	6.4
1998	1,789	1,756	1.9	1,675	1,595	5.0
1999	2,096	2,018	3.9	1,754	1,734	1.2
2000	2,169	2,065	5.0	1,941	1,843	5.3
2001	2,322	2,207	5.2	1,980	1,892	4.6
2002	2,217	2,109	5.1	2,120	2,043	3.7
2003	2,568	2,479	3.6	1,996	1,936	3.1
2004	2,610	2,546	2.5	2,052	1,994	2.9
2005	2,719	2,626	3.5	2,220	2,115	5.0
Average Percent Loss			3.7			4.3

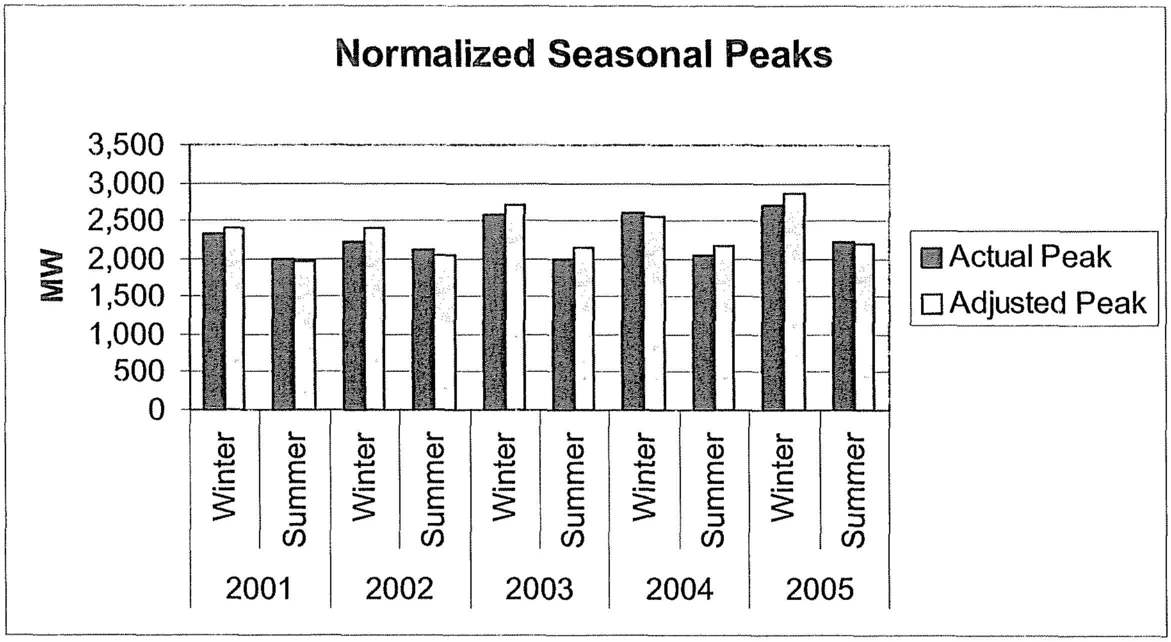
8.2 Weather Normalized Historical Peaks

The weather normalized coincident peak demands for winter and summer are shown in Table 8-2 and in Figure 8-1.

Table 8-2
Weather Normalized Coincident Peak Demands

Year	Season	Actual Peak	Adjusted Peak
		MW	MW
2001	Winter	2,322	2,402
	Summer	1,980	1,979
2002	Winter	2,217	2,392
	Summer	2,120	2,056
2003	Winter	2,568	2,696
	Summer	1,996	2,134
2004	Winter	2,610	2,562
	Summer	2,052	2,179
2005	Winter	2,719	2,863
	Summer	2,220	2,198

Figure 8-1
Weather Normalized Coincident Peak Demands



8.3 Peak Demand and Scenario Results

In addition to the forecasted peaks, high and low cases around the base case are developed. The same methodology is used, however, the starting summary file is different. Instead of using the sum of the member system files, two new models are built: one reflecting assumptions that result in high usage and one with assumptions that result in low usage. The assumptions that are varied include:

1. Weather – assumed 2 standard deviations above and below the base case heating and cooling degree day (HDD and CDD) assumptions
2. Electric price – assumed the residential rate would be 15% higher than the base case rate, which results in lower usage, for the low case and 15% lower for the high case
3. Residential customers – assumed 2 standard deviations above and below the base case annual average residential customers
4. Appliance saturation projections for the residential class
5. Small and Large Commercial energy – energy was modeled probabilistically, assuming a normal distribution and a standard deviation based on the historical data; the resulting 90%/10% output was used as the forecasted class energy

Adjusting these assumptions leads to different customer forecasts which in turn results in different energy forecasts. For the small and large commercial classes, the customer and energy forecasts for the high and low case are produced using probabilistic modeling in @RISK. The customer and energy forecasts are added to the residential forecast to produce the system forecast which is then used to create the hourly forecasts as described above.

After the annual energies and seasonal peaks for the cases are prepared, the same process of calibrating the system shape to these levels is followed. The results are shown in Tables 8-3 and Figures 8-2 through 8-4.

Table 8-3

Peak Demand Scenarios

Total Winter Peak Demand (MW)				Total Summer Peak Demand (MW)				Total Requirements Includes Gallatin Steel (MWh)			
Season	Low Case	Base Case	High Case	Year	Low Case	Base Case	High Case	Year	Low Case	Base Case	High Case
				2006	1,829	2,159	2,423	2006	11,362,043	12,556,759	13,743,274
2006 - 07	2,461	2,781	3,134	2007	1,894	2,221	2,490	2007	11,632,503	12,956,841	14,101,331
2007 - 08	2,486	2,856	3,207	2008	2,252	2,651	2,883	2008	13,595,326	14,793,556	16,227,134
2008 - 09	2,876	3,354	3,675	2009	2,382	2,729	3,025	2009	14,248,260	15,716,559	16,942,950
2009 - 10	3,005	3,447	3,838	2010	2,452	2,799	3,099	2010	14,658,388	16,133,913	17,397,030
2010 - 11	3,090	3,528	3,948	2011	2,513	2,860	3,161	2011	15,007,769	16,499,166	17,774,167
2011 - 12	3,162	3,603	4,039	2012	2,571	2,915	3,223	2012	15,393,533	16,879,983	18,202,463
2012 - 13	3,232	3,702	4,131	2013	2,638	2,986	3,299	2013	15,757,977	17,261,436	18,627,485
2013 - 14	3,320	3,783	4,249	2014	2,695	3,044	3,362	2014	16,098,941	17,621,408	19,016,207
2014 - 15	3,391	3,864	4,344	2015	2,755	3,104	3,424	2015	16,447,962	17,981,314	19,398,083
2015 - 16	3,462	3,939	4,437	2016	2,810	3,161	3,486	2016	16,817,895	18,370,418	19,823,838
2016 - 17	3,527	4,039	4,525	2017	2,876	3,233	3,558	2017	17,160,817	18,744,186	20,210,546
2017 - 18	3,608	4,126	4,632	2018	2,941	3,298	3,628	2018	17,540,219	19,129,686	20,631,709
2018 - 19	3,686	4,217	4,734	2019	3,009	3,367	3,701	2019	17,930,178	19,539,698	21,065,767
2019 - 20	3,765	4,307	4,839	2020	3,071	3,431	3,771	2020	18,348,908	19,977,370	21,552,290
2020 - 21	3,838	4,416	4,940	2021	3,147	3,513	3,856	2021	18,753,186	20,408,388	22,011,445
2021 - 22	3,933	4,511	5,065	2022	3,217	3,585	3,934	2022	19,161,057	20,837,354	22,479,811
2022-2023	4,015	4,605	5,177	2023	3,281	3,656	4,006	2023	19,543,672	21,258,006	22,920,966
2023-2024	4,092	4,686	5,282	2024	3,338	3,717	4,064	2024	19,936,295	21,683,180	23,352,014
2024-2025	4,157	4,789	5,369	2025	3,410	3,796	4,146	2025	20,295,933	22,086,886	23,769,925
2025-2026	4241	4,877	5483	2026	3,467	3,861	4,209	2026	20,639,435	22,475,651	24,163,368

Figure 8-2
Total Requirements

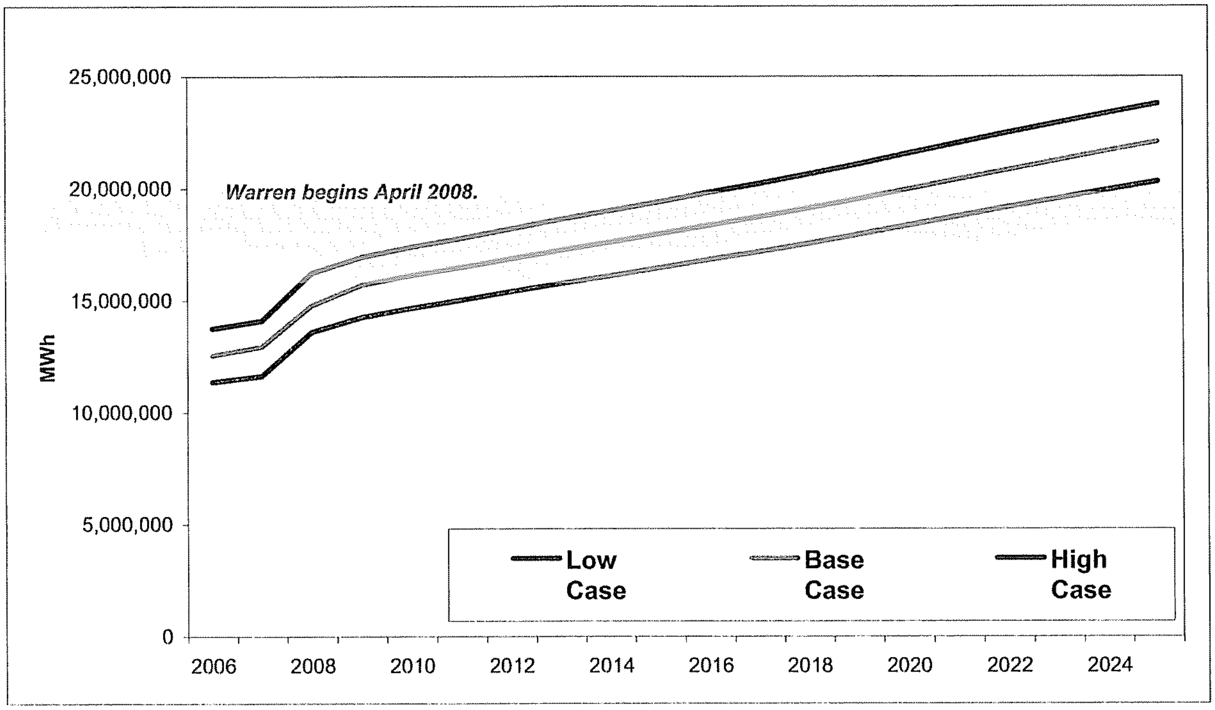


Figure 8-3
Total Winter Peak

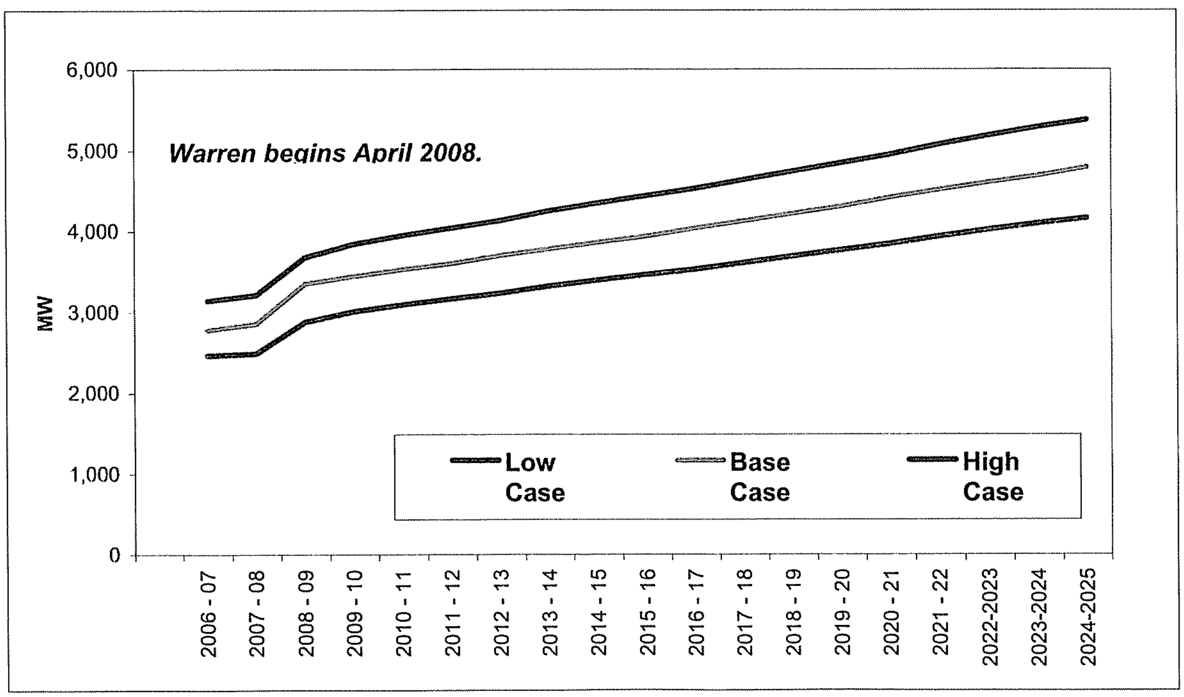
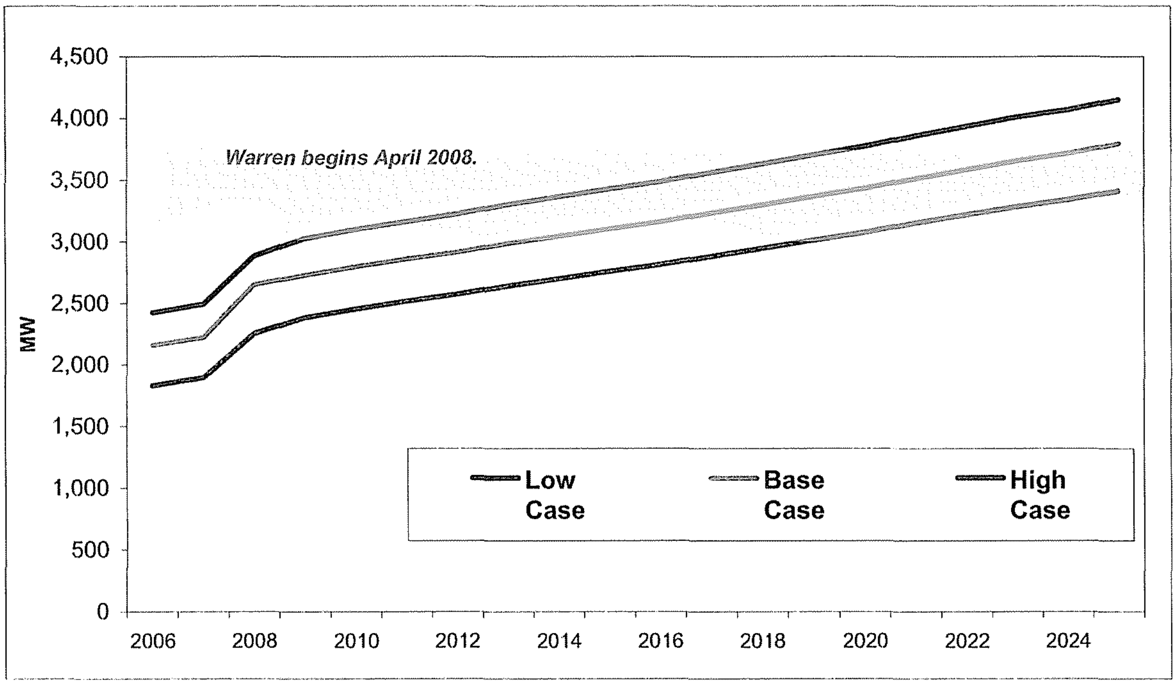


Figure 8-4
Total Summer Peak



EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2006-00463
INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007
REQUEST NO. 11
RESPONDING PERSON: DARRIN ADAMS

Request 11: a. Provide the parameters used to rate EKPC transmission components; (i.e., input to the rating programs).

b. Provide transmission line rating sheets showing the ratings of the various transmission line components and limiting component.

Response: (a)

A. Transmission Circuit

1. The current carrying capacity of each transmission facility is determined by the minimum current carrying capability of all series connected elements on that facility. Elements that are considered include the thermal rating of the conductor, circuit breakers, bushings, current transformers, bus, disconnect switches, wave traps, protective relaying and series reactors. The limiting ratings for a transmission facility will be derived from a single set of ratings consisting of all series elements within the facility. The most limiting rating will be recognized as the rating for the given transmission facility. The determination for the current carrying capability of each of these facilities is discussed below.

2. ***Conductor Thermal Rating***

i) Methodology

The ECAR Conductor Thermal Rating Program (68-TAP-28) is used by EKPC. This program is based on modification of the "House and Tuttle" methodology that is used for determining continuous current carrying capability of transmission line conductors. This method was published in AIEE Transaction, Power Apparatus Section, February 1959, Volume 40, page 1169, entitled "Current Carrying Capability of ACSR". It is also available in the ALCOA Conductor Engineering Handbook, Section 6.

ii) Key Assumptions

(1) All of the key assumptions used in the equations for determining the Conductor Thermal Ratings are given below:

(2) Emissivity Coefficient	0.8
(3) Solar Absorption Coefficient	0.8
(4) Ambient temperature (degrees C)	
(a) Summer	35
(b) Winter	0
(5) Wind /Conductor angle (degrees)	90
(6) Wind Velocity (mph)	2
(7) Conductor Max. Temp. (degrees C)	
(a) Normal (continuous rating)	80 *
(b) Emergency (24 hr limit) max. line design temp(generally100)	

(8) All solar heating is considered regardless of time of day or sky conditions. The maximum design temperature for the line is used if below the 80 degree C (normal rating).

iii) Justification

1. The methodology is recognized throughout the industry. The ECAR, AIEE, and Alcoa sources listed above (Paragraph 1) were used to provide a guide for selecting the program inputs based on EKPC's system characteristics. The emissivity and solar

absorption coefficients are reasonable values for aged conductors. Ambient conditions are reasonable and prudent values based on climate, statistical analysis, and experience in the EKPC geographic area.

a. Circuit Breakers

i. Circuit breakers will be operated within the manufacturer's nameplate rating of the equipment for both continuous and emergency ratings. In cases where a bushing or current transformer would limit the nameplate rating, the rating of the circuit breaker will be determined by the limiting component.

ii. A methodology for rating of CTs is outlined in the Westinghouse "Memorandum On Thermal Characteristics of Current Transformers Used with Circuit Breakers" dated 6/26/69: $R.F. = \sqrt{I_b/I_{ct}}$, *where* I_b *is breaker nameplate rating,* I_{ct} *is CT primary rating on the tap used.* This factor is multiplied by the normal rating factor of the CT. The maximum rating factor must not exceed 2.0.

b. Bushings

i. Bushings will be operated within the manufacturer's nameplate rating of the bushing for both continuous and emergency ratings.

c. ***Current Transformers***

i. Current transformers will be operated within the manufacturer's nameplate rating of the current transformer for both continuous and emergency ratings.

d. *Bus*

i. Typically, the rating of the bus is determined using same methodology as that used to determine conductor rating. In most cases the bus is designed so as to not limit the transmission line rating. In instances where the bus is the limiting factor, the rating of the transmission facility will be determined by the bus rating.

e. ***Disconnect Switches***

i. Disconnect switches will be operated within ratings determined by multiplying the manufacturer's nameplate rating and the following factors for both continuous and emergency ratings:

1. The summer normal rating is obtained by multiplying the nameplate rating by 1.05.
2. The summer emergency rating is obtained by multiplying the nameplate rating by 1.20.
3. The winter normal rating is obtained by multiplying the nameplate rating by 1.25.
4. The winter emergency rating is obtained by multiplying the nameplate rating by 1.30.

The factors specified above are values conservatively developed based upon IEEE Std C37.37.

f. Wave Traps

i. Wave Traps will be operated within ratings determined by multiplying the manufacturer's nameplate rating and the following factors for both continuous and emergency ratings:

1. The summer normal rating is obtained by multiplying the nameplate rating by 1.01.
2. The summer emergency rating is obtained by multiplying the nameplate rating by 1.04.
3. The winter normal rating is obtained by multiplying the nameplate rating by 1.12.
4. The winter emergency rating is obtained by multiplying the nameplate rating by 1.15.

The factors specified above are values conservatively developed based upon ECAR Guide 88-EEP-42.

g. Protective Relaying

i. Typically, relay settings will be applied so as not to limit the loadability of the conductor on a circuit. However, in some cases the relay settings may need to limit the conductor rating in order to provide adequate protection for the circuit. In such cases, the rating of the transmission line will be determined by this limiting factor.

1. In cases where the relay loadability at maximum torque is inadequate, the relay will be rated at 90% power factor if load flow studies confirm this is appropriate. The relay rating at 90% power factor is then derated by 10% to account for relay circuit tolerances.

h. Series Reactors

i. Series reactors will be operated within the manufacturer's nameplate rating of the equipment for both continuous and emergency ratings.

i. Shunt Reactive Devices

i. Shunt reactive devices will be operated within the manufacturer's nameplate rating of the equipment for both continuous and emergency ratings.

iv) HV Power Transformers

a. Transmission class HV power transformers have nominal and emergency ratings for summer and winter. The nominal rating may be applied continuously and the emergency rating for 4 hours. Summer ambient ratings are in effect from June 1 through October 31. Winter ambient/ratings are in effect from November 1 through May 30.

i. <u>65° C Rise</u>

1. The continuous current carrying capabilities of HV power transformers is determined by an adaptation of the methodology contained in NEMA PUB. NO. TR 98-1964 which is called "Standards Publication Guide for Loading Oil-Immersed Power Transformers with 65 C Average Winding Rise" for OA or OW and OA/FOA/FOA transformers.
2. In multiplying the nameplate rating by 90% of the continuous equivalent load of 24 hours rated KVA preceding peak load in the Table 2-2, Part 2, Page 4 of PUB. NO. 98, the normal ratings of the transformer would be obtained. The nominal limit for all EKPC transformers is the maximum hot spot temperature.
3. The emergency ratings are based on a peak load time of 4 hours or less and a loss of life of 1.0% or less for each emergency operation, which is shown in Table 3-6 of PUB. NO. TR 98, Part 3, Page 7. Emergency rating assumed the transformer was operating within nominal limits prior to the emergency operation.
4. Therefore, based on ambient temperatures of 35°C for summer and 0°C for winter, the multipliers used to develop ratings for EKPC power transformers are:

   <u>For OA transformers</u>

   Summer Normal = 95% of nameplate

Summer Emergency = 136% of nameplate

Winter Normal = 126% of nameplate

Winter Emergency = 176% of nameplate

For OA/FOA/FOA transformers

Summer Normal = 96.5% of nameplate

Summer Emergency = 129% of nameplate

Winter Normal = 119% of nameplate

Winter Emergency = 147% of nameplate

ii. 55° C Rise

1. The methodology (tables) contained in the USAS Appendix: C57.92, called "Standard Institute Guide for Loading Oil-Immersed Distribution and Power Transformers" was published in June 1962.
2. In multiplying the nameplate rating by 90% of continuous equivalent load or rated KVA preceding peak load (Table 92-01.250A), the nominal ratings of the transformer would be obtained. The nominal ratings of the transformers are the maximum hot spot temperature.
3. The emergency ratings are based on table 92.02.200P, Page 28, Capability Table for Forced-Oil-Cooled Transformers (FOA, FOW, or OA/FOA/FOA), and 4 hours or less and a loss of life of

1.0% or less for each emergency operation. Emergency rating assumes that the transformer was operating within nominal limits prior to the emergency operation.

4. Therefore, based on ambient temperatures of 35°C for summer and 0°C for winter, the multipliers used to develop ratings for EKPC power transformers are:

For OA transformers

Summer Normal = 94.5% of nameplate

Summer Emergency = 142.5% of nameplate

Winter Normal = 133% of nameplate

Winter Emergency = 180% of nameplate

For OA/FOA/FOA transformers

Summer Normal = 94.5% of nameplate

Summer Emergency = 134.5% of nameplate

Winter Normal = 130% of nameplate

Winter Emergency = 165% of nameplate

As with transmission lines, the rating of a transformer circuit is equal to the minimum of the current-carrying capability of all series-connected elements in the transformer circuit. Elements that are considered include the thermal rating of conductors, circuit breakers, bushings, current transformers, bus, disconnect switches, wave traps, protective relaying and series reactors.

v) Jointly-Owned and Jointly-Operated Transmission Facilities

The limiting ratings for a jointly-owned and/or jointly-operated transmission facility will be derived from a single set of ratings consisting of all series elements within the facility. The owners and/or operators will jointly develop the single set of ratings by applying their respective methodologies on series elements in which they own. The most limiting rating will be recognized by all owners and/or operators as the rating for the given transmission facility.

Response: (b) The response for this portion of Staff's First Data Request is the subject of the Applicant's Petition for Confidential Treatment and is included in that Petition filed this date.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2006-00463

INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007

REQUEST NO. 12

RESPONDING PERSON: DARRIN ADAMS

Request 12: Refer to the minutes of the July 12, 2005 meeting of EKPC's Board of Directors in which the proposed project was approved.

a. Explain why the North Clark terminal was substituted for the Stanford terminal.

b. Explain why the West Garrard terminal was substituted for the Stanford terminal.

c. State whether these substitutions are different projects. If they are different projects, explain why the approved dollar amount does not change.

d. Explain why the Board approved the project almost one year before the SIS studies were completed in May 2006.

Response: **(a)** EKPC's Transmission Planning department recommended construction of a new 345 kV line from J.K. Smith to the existing Spurlock-Avon 345 kV line at a point adjacent to EKPC's existing Sideview 69 kV distribution substation. During implementation of this project, EKPC chose to name the new substation North Clark to avoid confusion, since the new substation is not physically connected to the existing Sideview substation, although it is in close proximity.

Response: **(b)** The J.K. Smith system impact study results indicated that the preferred transmission expansion plan to accommodate the additional generating units at J.K. Smith consists of a new 345 kV line from the J.K. Smith Station to the E-ON U.S. Brown-Pineville 345 kV double-circuit line. The assumption for the planning study was that this point would be in the vicinity of Stanford, KY. Subsequent field review by EKPC design engineers indicated that this substation should be moved northward a few miles based upon line and substation siting considerations. The final substation site chosen for termination of the new line was in western Garrard County.

Response: **(c)** The substitution of North Clark for Sideview is primarily a change in name only. The final location of the North Clark substation is nearly identical to that envisioned in the planning study. The substitution of West Garrard for Stanford is due to the substation location being moved a few miles. However, the scope of the substation remains identical. The only difference is the physical location. Therefore, the cost estimates developed by EKPC's Transmission Planning department would not change, since these estimates generally are not based on site-specific issues. More detailed, site-specific engineering estimates are usually not developed until the facility design process is completed.

Response: **(d)** EKPC submits transmission expansion projects to its Board of Directors for approval when adequate analysis has been completed to determine the preferred transmission expansion plan to address a particular set of problems. Often times, additional analysis is still necessary to finish a study, even after the Board of Directors has approved a project. Occasionally, changes in study results, estimated cost, etc. will result in a revised recommendation to the Board of Directors. Therefore it is not uncommon to seek approval prior to the completion of the study. The approval by the Board of Directors allows EKPC to allot funds for the engineering and environmental work necessary to implement the project. Due to the length of time often involved in these tasks, it is important to seek approval by the Board of Directors as soon as feasible. In this case, EKPC completed its initial planning analysis prior to July of 2006. This analysis indicated that the expansion plan that included the J.K. Smith-West Garrard project was the preferred solution to the problems produced by the addition of the J.K. Smith generating units. Transmission Planning staff presented this recommendation to the EKPC Board at its July 12, 2005 meeting based upon the study results as of that date.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2006-00463
INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007
REQUEST NO. 13
RESPONDING PERSON: BRANDON GRILLON

Request 13: Refer to Filing Exhibit 3, page 5. Describe the involvement of Photo Science Geospatial Solutions and EKPC in the route selection process.

Response: Photo Science Geospatial Solutions was employed to gather the necessary data and perform the statistical analysis associated with the EPRI/GTC methodology. Photo Science gathered and verified the necessary information but made no decisions in selecting the preferred route. EKPC followed the EPRI/GTC methodology and incorporated information gathered from open houses and surveys to make decisions in the route selection process. The route selection process is documented in EKPC's *Selection of Preferred Route: Smith to West Garrard 345-kV Transmission Project*, which was submitted in the application as Warner Exhibit 2.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2006-00463
INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007
REQUEST NO. 14
RESPONDING PERSON: BRANDON GRILLON

Request 14: Refer to Filing Exhibit 3, page 16 at which the Kentucky Siting Model is described. Recognizing that the model's parameters and their relative weights were developed on a state-wide basis, how did EKPC include more localized considerations in its route selection process for these parameters?

Response: As shown on Figure 1 on page 2 of the *Selection of Preferred Route: Smith to West Garrard 345-kV Transmission Project* (Warner Exhibit 2), EKPC augmented the EPRI/GTC methodology to include open houses after the creation of the Alternative Corridors. RUS conducted a public scoping meeting in Richmond, KY on July 11, 2006 to solicit information and gather comments on the Alternative Corridors generated from the EPRI/GTC methodology. The *Macro-Corridor Study: Smith to West Garrard 345-kV Transmission Project* (Warner Exhibit 1) was available at this open house for comment. This study was also available at public libraries in Clark, Madison, and Garrard counties during the comment period. Comments received from this open house are attached as Appendix A to Warner Exhibit 2.

EKPC also hosted two other public open houses on August 29, 2006 in Lancaster, KY and on August 31, 2006 in Richmond, KY. These open houses presented the

Alternative Route Corridors to the public and individuals who owned property. Individuals owning property within the Alternative Route Corridors received personal invitations to an open house in their locale. The Alternative Route Corridors are shown on Figure 11 in Warner Exhibit 2. Comments received from these EKPC open houses are attached as Appendix B to Warner Exhibit 2.

EKPC personnel then met to further refine the Alternative Route Corridors into route segments, taking into account the information that was gathered at the open houses. Appendix C of Warner Exhibit 2 lists actions or responses by EKPC to determine the refined route segment locations.

Notification was given to the property owners in the corridors to let them know whether the proposed route would or would not be crossing their property. A map showing the approximate line location per available PVA data was also attached to better help the property owners visualize how the line would be crossing their property. An EKPC contact number was given in this letter in case the property owner had any further questions about the route as it pertained to their property.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2006-00463

INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007
REQUEST NO. 15
RESPONDING PERSON: BRANDON GRILLON

Request 15: At Filing Exhibit 3, page 18, the weightings and importance of the various parameters in the Kentucky Siting Model are depicted. Under the "Built Environment" parameter, the "Proximity to Eligible Historic and Archeological Sites" importance factors appear to state that these sites are more suitable when within 300 feet of a new line than when 300 to 600 feet distant

a. State whether this interpretation of the importance factors is correct. Explain.

b. State whether the values used in the Kentucky Siting Model for the "Built Environment" parameter are correct. If not correct, provide the correct values and state the effect of the correct values on the siting analysis. If correct, explain why a route is more desirable when closer to a historic or archeological site.

Response: These values are correct per the stakeholder calibration conducted on February 28, 2006. Attached as response to Data Request 2 is the *Kentucky Transmission Line Siting Model Project Report* that details the calibration of the EPRI/GTC siting model to Kentucky concerns. This counter-intuitive result is noted in the Feature Calibration section of the Built Environment Report on page 2-9, which notes a lack of group consensus as causing this result. However, the consulting team discussed this result and arrived at the opinion that the difference was so small, it is unlikely to have a meaningful difference in the model results.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2006-00463

INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007

REQUEST NO. 16

RESPONDING PERSON: DARRIN ADAMS

Request 16: At Filing Exhibit 3, page 31, the transmission lines that represent bad rebuilding opportunities are listed. For each listed transmission line, explain why it is a bad rebuilding opportunity.

Response: The following is a summary of the analysis results that identified the bad rebuild opportunities:

Dale-Hunt 69 kV Double-Circuit

The estimated outage time is 4 months. Based upon the expected outage duration, this outage would occur at or near either a summer or winter peak. Analysis of 2007 Summer peak conditions shows that the JK Smith 12 kV voltage during this outage is 91.7% (criterion is 95.5%). For the next critical contingency – the Powell County 138-69 kV transformer – the JK Smith 12 kV voltage would be decreased to 79.7% (criterion is 92.5%).

Analysis of 2007-08 Winter peak conditions shows that the JK Smith 12 kV voltage during this outage is 90.5% (criterion is 95.5%). Also the Powell County 138-69 kV transformer flow is 121.2 MVA (rating is 119 MVA). During the next critical contingency – the Powell County 138-69 kV transformer – the voltage at the Sideview 12 kV bus is 73.21% (criterion is 92.5%) and the flow on the Powell County 161-138 kV transformer is 189.8 MVA (rating is 178 MVA) and the flow on the Beattyville 161-69 kV transformer is 67.3 MVA (rating is 67 MVA).

Therefore, due to the probability of unacceptable voltage levels and the possibility of excessive loading of the Powell County 138-69 kV, Powell County 161-138 kV, and Beattyville 161-69 kV transformers, this outage is not desirable.

Fawkes-Crooksville Jct.-Hickory Plains 69 kV Line

The estimated outage time is 2 to 3 months. This outage could occur in either a spring or fall window. An analysis of a shoulder peak case (80% load level) was therefore performed.

An analysis of a shoulder load model (75% of peak load) for a subsequent contingency of the Fawkes-West Berea 138 kV line and/or the West Berea 138-69 kV transformer results in non-convergent cases. Therefore, possible voltage collapse could occur even for shoulder peak load conditions.

Therefore, due to this risk of voltage collapse for a second contingency, this outage should be avoided.

Dale-Fawkes 138 kV Line

The estimated outage time is 4 to 5 months. Based upon the expected outage duration, this outage would occur at or near either a summer or winter peak. Analysis of 2007 Summer peak conditions shows that for the next critical contingency – the JK Smith-Union City 138 kV line – the flow on the JK Smith-Fawkes 138 kV line is 326.5 MVA (rating is 311 MVA).

Analysis of 2007-08 Winter peak conditions shows that with the JK Smith-Union City 138 kV line outaged, the flow on the JK Smith-Fawkes 138 kV line is 468.5 MVA (rating is 389 MVA).

Assuming the work is scheduled to avoid the winter months, the estimated number of hours of generation re-dispatch is approximately 100 during the summer months. Assuming an average redispatch of approximately 100 MW from the JK Smith CTs to off-system purchases at an incremental cost of $50/MWh, the total estimated redispatch cost during this outage would be $500,000.

Therefore, due to the possibility of uneconomic dispatch during this outage, rebuilding is not a desirable option.

JK Smith-Dale 138 kV Line

The estimated outage time is 6 to 7 months. Based upon the expected outage duration, this outage would occur at either a summer or winter peak. Analysis of 2007 Summer peak conditions shows that for the next critical contingency – the JK Smith-Union City 138 kV line – the flow on the JK Smith-Fawkes 138 kV line is 321.9 MVA (rating is 311 MVA).

Analysis of 2007-08 Winter peak conditions shows that with the JK Smith-Union City 138 kV line outaged, the flow on the JK Smith-Fawkes 138 kV line is 464.3 MVA (rating is 389 MVA).

Assuming the work is scheduled to avoid the winter months, the estimated number of hours of generation re-dispatch is approximately 75 during the summer months. Assuming an average redispatch of approximately 75 MW from the JK Smith

CTs to off-system purchases at an incremental cost of $50/MWh, the total estimated redispatch cost during this outage would be $281,250.

Therefore, due to the possibility of uneconomic dispatch during this outage, rebuilding is not a desirable option.

Fawkes-West Berea 138 kV Line

The estimated outage time is 4 to 5 months. Based upon the expected outage duration, this outage would occur at or near either a summer or winter peak.

An analysis of the 2007 Summer and 2007-08 Winter conditions for a subsequent outage of the Fawkes-Crooksville Jct. 69 kV line results in non-convergent cases. A shoulder load model (75% of peak load) was also utilized, but the case remains divergent for this subsequent contingency. Therefore, possible voltage collapse could occur at either peak or shoulder peak load conditions.

Therefore, due to this risk of voltage collapse for a second contingency, this outage should be avoided.

JK Smith-Fawkes 138 kV Line

The estimated outage time is 8 to 9 months. Based upon the expected outage duration, this outage would occur at either a summer or winter peak. Analysis of 2007 Summer peak conditions shows that for the next critical contingency – the JK Smith-Union City 138 kV line – the flow on the JK Smith-Dale 138 kV line is 334.8 MVA (rating is 311 MVA) and the flow on the Dale-Three Forks Jct. 138 kV line is 316.2 MVA (rating is 222 MVA).

Analysis of 2007-08 Winter peak conditions shows that with the JK Smith-Union City 138 kV line outaged, the flow on the JK Smith-Dale 138 kV line is 497.0 MVA (rating is 389 MVA) and the flow on the Dale-Three Forks Jct. 138 kV line is 439.9 MVA (rating is 278 MVA).

Assuming the work is scheduled to avoid the winter months, all generation would still need to be taken offline at JK Smith to avoid these issues for the next contingency. Therefore, EKPC would be unable to dispatch the generation at JK Smith for the duration of the outage. Furthermore, additional generation reductions at Spurlock Station would be required to reduce the flows below the applicable ratings.

Therefore, due to the severe generation restrictions during this outage, rebuilding is not a viable option.

JK Smith-Union City-Lake Reba Tap 138 kV Line

The estimated outage time is 6 to 7 months. Based upon the expected outage duration, this outage would occur at either a summer or winter peak.

The problems for this scenario are identical to the problems detailed above for the JK Smith-Fawkes 138 kV line outage, since the next critical contingency in this case is the JK Smith-Fawkes 138 kV line.

Therefore, due to the severe generation restrictions during this outage, rebuilding is not a viable option.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2006-00463

INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007

REQUEST NO. 17

RESPONDING PERSON: DARRIN ADAMS

Request 17: Refer to Filing Exhibit 4, page 7. Explain why the decision of Warren Rural Electric Cooperative Corporation to continue to purchase its total power requirements from the Tennessee Valley Authority does not alter the need for the J. K. Smith to West Garrard 345 kV line.

Response: This line is needed due to the planned addition of generation at the J.K. Smith site. Studies indicate that the addition of more than approximately 100 MW of generation at J.K. Smith will trigger the need for transmission modifications due to overloads of existing 138 kV outlets from the J.K. Smith Station. EKPC's latest generation expansion plan indicates the need for two CTs in 2009 and the J.K. Smith baseload CFB unit in 2010. Therefore, the need for additional transmission still exists to provide adequate outlet capability for the 474 MW of total added generation that these unit additions represent. Furthermore, EKPC's generation expansion plan includes installation of three additional CTs in the 2012-2014 time period. Therefore, the total potential amount of generation added at J.K. Smith from 2009 through 2014 is 768 MW. This level of generation is consistent with the assumptions made in the SIS. Therefore, the study results are still valid. Also, a second CFB baseload unit at J.K. Smith is possible by 2017. The Smith-West Garrard 345 kV line will provide outlet capability for this unit addition as well.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2006-00463

INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007

REQUEST NO. 18

RESPONDING PERSON: DARRIN ADAMS

Request 18: Provide the power factors of each EKPC system member at the time of its 2006 summer and winter peaks.

Response:

	2006 Summer CP (1)			2006/07 Winter CP (2)		
Cooperative	**MW**	**MVA**	**PF**	**MW**	**MVA**	**PF**
Jackson Energy			0.960			0.987
Salt River Electric			0.954			0.989
Taylor County RECC			0.938			0.981
Inter-County Energy			0.963			0.992
Shelby Energy			0.954			0.979
Farmers RECC			0.930			0.975
Owen Electric			0.945			0.970
Clark Energy			0.952			0.990
Nolin RECC			0.939			0.980
Fleming-Mason Energy			0.931			0.968
South Kentucky RECC			0.956			0.985
Licking Valley RECC			0.951			0.989
Cumberland Valley Electric			0.965			0.992
Big Sandy RECC			0.963			0.993
Grayson RECC			0.952			0.987
Blue Grass Energy			0.931			0.976
EKPC System Total	2212.58	2335.17	0.948	2704.50	2754.09	0.982

Notes:

1. Time of 2006 Summer Peak: 8/2/2006 17:00
2. Time of 2006/07 Winter Peak: 2/16/2007 7:15

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2006-00463
INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007
REQUEST NO. 19
RESPONDING PERSON: DARRIN ADAMS

Request 19: Provide the screening analysis that was performed to determine the July 2005 transmission recommendations to the EKPC Board of Directors.

Response: The response for this Data Request is the subject of the Applicant's Petition for Confidential Treatment and is included as **Data Request 19 Exhibit A** in that Petition filed this date.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2006-00463
INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007
REQUEST NO. 20
RESPONDING PERSON: DARRIN ADAMS

Request 20: Provide all documents that were presented or made available to EKPC's Board of Directors for its July 2005 meeting regarding transmission construction recommendations of 345 kV facilities.

Response: Provided as **Response to Staff's Data Request 20** is a copy from the Minute Book of the Board of Directors of East Kentucky Power Cooperative, Inc.

**FROM THE MINUTE BOOK OF PROCEEDINGS
OF THE BOARD OF DIRECTORS OF
EAST KENTUCKY POWER COOPERATIVE, INC.**

At a regular meeting of the Board of Directors of East Kentucky Power Cooperative, Inc. held at the Headquarters Building, 4775 Lexington Road, located in Winchester, Kentucky, on Tuesday, July 12, 2005, at 11:35 a. m., EDT, the following business was transacted:

J. K. Smith Transmission Expansion Projects

After review of the applicable information, a motion was made by Fred Brown, seconded by Mike Adams, and, following further discussion, passed to approve the following:

Whereas, East Kentucky Power Cooperative, Inc., ("EKPC") engineering studies have confirmed the necessity and advisability of the following projects included in the July 12, 2005 Amendment to the EKPC Rural Utilities Service ("RUS") approved Three-Year Work Plan (November 2002-October 2005):

J.K. Smith CTs #8-12 Terminal Facility Additions	$4,740,000
Two new J.K. Smith 345-138 kV Autotransformer Additions	$5,836,000
New J.K. Smith CFB Substation	$2,257,000
Two new 345 kV J.K. Smith CT-J.K. Smith CFB Lines	$10,231,000
J.K. Smith-S~~ideview~~ 345 kV Line N. Clark	$14,299,000
North Clark ~~Sideview~~ 345 kV Substation	$3,385,000
J.K. Smith-~~Stanford~~ 345 kV Line W. Garrard	$38,419,000
W. Garrard ~~Stanford~~ 345 kV Substation	$3,470,000
LGEE's Addition of 345 kV Terminal Facilities at Brown and Pineville	$2,313,000
Enlarge Dale 138-69 kV Autotransformer	$984,000
LGEE's Alcalde-Elihu 161 kV, Fawkes-Clark County 138 kV, Shelby City-Stanford 69 kV, and Waco-Rice 69 kV Operating Upgrades	$636,000
LGEE's Boonesboro North 69 kV Breaker Replacements (2)	$266,000
LGEE's Fawkes-Clark County 138 kV Switch Replacements	$58,000

Whereas, Review by the Power Delivery ("PD") Committee and approval of the EKPC Board of Directors ("Board") is required for the construction and financing of these projects pursuant to Board Policies No. 103 and 106;

Whereas, The current EKPC Three-Year Work Plan (November 2002-October 2005) dated October 2002, has been submitted to RUS for approval, which requires that any amendment thereto be approved by the Board;

Whereas, EKPC management and the PD Committee recommend that the Board amend the current EKPC RUS approved Three Year Work Plan and approve construction of these projects, the acquisition of all real property and easement rights, by condemnation if necessary, and the obtaining of permits and approvals necessary and desirable for these projects and include the financing of these projects with general funds, subject to reimbursement from construction loan funds should they become available and the Board will act upon said recommendation this date; and

Whereas, This recommendation supports the delivery of facilities at a competitive cost, on time, and of good quality; now, therefore, be it

Resolved, That EKPC management is authorized to amend the current EKPC RUS approved Three-Year Work Plan to include the above projects summarized in more detail in the attached Executive Summary;

Resolved, That approval is hereby given for construction of said projects included in the April 12, 2005 Amendment to the EKPC Three-Year Work Plan (November 2002-October 2005), at an estimated total cost of $86,894,000 and for the acquisition of all real property and easement rights, by condemnation if necessary, as well as all necessary permits and approvals for these projects; and

Resolved, That approval is hereby given to amend the EKPC Annual Budget and Work Plan to include the projects and to finance them with general funds, subject to reimbursement from construction loan funds should they become available.

The foregoing is a true and exact copy of a resolution passed at a meeting called pursuant to proper notice at which a quorum was present and which now appears in the Minute Book of Proceedings of the Board of Directors of the Cooperative, and said resolution has not been rescinded or modified.

Witness my hand and seal this 12th day of July 2005.

A. L. Rosenberger

A. L. Rosenberger, Secretary

Corporate Seal

JULY

Board Agenda Item

TO: Power Delivery Committee and Board of Directors

FROM: Roy M. Palk Roy M. Palk

DATE: July 1, 2005

SUBJECT: Approval of J.K. Smith Transmission Expansion Projects, and Amendment of EKPC Three Year Work Plan (November 2002-October 2005)
(Construction and Finance)
(Executive Summary)

KEY MEASURE(S) This action supports the delivery of facilities at a competitive cost, on time and of good quality.

Background

An Amendment to the East Kentucky Power Cooperative's ("EKPC") Rural Utilities Service ("RUS")-required Three-Year Work Plan (November 2002-October 2005) identifies additional transmission facilities and modifications needed by EKPC to economically and reliably serve projected load growth. This work plan amendment was developed from the results of load flow and economic analysis using input from EKPC member system work plans, EKPC's Market Research Process, Power Delivery Maintenance Process and Power Delivery Expansion Process.

This amendment basically covers two categories of projects including:

(1) Transmission Line Additions

(2) New Substations, Substation Additions and/or Modifications

These projects are proposed as a result of transmission studies associated with the new J.K. Smith Combustion Turbine Units (CTs) #8 through #12 and the new J.K. Smith Circulating-Fluidized Bed (CFB) Unit.

Justification and Strategic Analysis

Power flow analysis and transient stability analysis were conducted with the proposed generator additions to identify inadequacies in the transmission system. Alternative transmission plans to address these inadequacies were developed. The studies and

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evaluation of alternatives have been coordinated with AEP, Big Rivers Electric Corp., Cinergy, Dayton Power & Light, LG&E Energy, the Midwest ISO, and TVA.

The resulting recommendation is that the projects listed below are needed to provide acceptable stability for the J.K. Smith Units, and to provide the needed transmission capacity for both normal and first-contingency expected system flows that will be created by these Units. These projects will integrate well with the long term plans for the system and the addition of generation at J.K. Smith. EKPC has provided this list of the recommended projects to the neighboring utilities involved in this study, and has requested the desired interconnection from LG&E Energy. The recommended projects and their expected costs are:

1. Addition of substation terminal facilities at the existing J.K. Smith CT Substation to connect J.K. Smith CTs #8 through #12 at a cost of $4,740,000.
2. Installation of two new 345-138 kV, 450 MVA autotransformers at the existing J.K. Smith CT Substation at a cost of $5,836,000.
3. Construction of a new 345 kV Substation at the J.K. Smith site to connect the J.K. Smith CFB Unit at a cost of $2,257,000.
4. Construction of two new 345 kV lines (1 mile each) and associated terminal facilities connecting the J.K. Smith CT Substation to the J.K. Smith CFB Substation at a cost of $10,231,000. N. Clark
5. Construction of a new 345 kV line (18 miles) ~~and~~ associated terminal facilities from the J.K. Smith CT Substation to the ~~Sideview~~ area at a cost of $14,299,000.
6. Construction of a new 345 kV substation connecting the Spurlock-Avon 345 kV line to the J.K. Smith-Sideview 345 kV line at a cost of $3,385,000. W. Garrard
7. Construction of a new 345 kV line (48 miles) and associa~~ted terminal~~ facilities from the J.K. Smith CFB Substation to the ~~Stanford~~ area at a cost of $38,419,000.
8. Construction of a new 345 kV substation connecting LGEE's Brown North-Pineville 345 kV line to the J.K. Smith-Stanford 345 kV line at a cost of $3,470,000.
9. At EKPC's expense, add terminal facilities at LGEE's Brown North and Pineville Substations to energize the Brown North-Pineville 345 kV line at a cost of $2,313,000.
10. Replace the Dale 138-69 kV autotransformer with a 100 MVA unit at a cost of $984,000.
11. At EKPC's expense, increase the maximum conductor operating temperature of LGEE's Alcalde-Elihu 161 kV, Fawkes-Clark County 138 kV, Shelby City-Stanford, and Waco-Rice 69 kV lines at a cost of $636,000.
12. At EKPC's expense, upgrade two 69 kV breakers at LGEE's Boonesboro North Substation at a cost of $266,000.
13. At EKPC's expense, upgrade line switches and disconnects in LGEE's Fawkes-Clark County 138 kV line at a cost of $58,000.

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The total cost for the proposed projects is $86,894,000. The target completion date for these projects is the 2007-2009 time period.

An alternative to this plan was evaluated that is similar in cost ($86,233,000). The major difference between this alternative and the proposed alternative is a new 345 kV line between J.K. Smith and Tyner (48 miles) as opposed to the J.K. Smith-Stanford 345 kV line. Although the estimated cost is slightly less for this alternative, the proposed alternative represented by the thirteen projects listed above provides several advantages that make it the preferred alternative. The primary advantage is that it provides a 345 kV connection from Spurlock and J.K. Smith to LGEE's EHV system that crosses the state of Kentucky, which will provide much more regional benefit than the alternatives which include the J.K. Smith-Tyner line. This configuration will reduce the impacts on EKPC of NERC Transmission Loading Relief (TLR) Procedures that are implemented to reduce line loadings on the 138 kV transmission system.

Recommendation

Management recommends that the EKPC Board approves an Amendment of the current EKPC RUS approved Three-Year Work Plan (November 2002-October 2005) dated October 2002, to include those projects identified above at estimated total costs of $86,894,000 and to approve construction of these projects along with authorization to acquire necessary permits, approvals, real property and associated easements necessary and desirable to implement these projects.

RUS requires approval of the Board for amendment of the current EKPC RUS-approved Three-Year Work Plan. Construction of the added projects requires review by the Power Delivery Committee and approval pursuant to Board Policies No. 103 and 106.

DA

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2006-00463

INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007

REQUEST NO. 21

RESPONDING PERSON: BRANDON GRILLON

Request 21: Breakout the count data information in the lower table in Filing Exhibit-10 into Greenfield, rebuild, and collation data.

Response: See **Data Request #21 Exhibit A** filed herein.

Smith - West Garrard 345 kV Transmission Line Prc

Built	Route E r	Route F r	Route G r	Route H r
Residences within the ROW	0	0	0	0
Rebuild T/L	-	-	-	-
Parallel T/L	-	-	-	-
New T/L	-	-	-	-
Proximity to Residences (300')	33	45	30	42
Rebuild T/L	17	33	16	32
Parallel T/L	9	9	7	7
New T/L	7	3	7	3
Proposed Residential Developments	3	2	3	2
Rebuild T/L	0	0	0	0
Parallel T/L	0	0	0	0
New T/L	3	2	3	2
Proximity to Commercial Buildings (300')	0	2	0	2
Rebuild T/L	0	2	0	2
Parallel T/L	0	0	0	0
New T/L	0	0	0	0
Proximity to Industrial Buildings (300')	0	0	0	0
Rebuild T/L	-	-	-	-
Parallel T/L	-	-	-	-
New T/L	-	-	-	-
School, DayCare, Church, Cemetery, Park Parcels (:	0	0	0	0
Rebuild T/L	-	-	-	-
Parallel T/L	-	-	-	-
New T/L	-	-	-	-
NRHP Listed/Eligible Strucs./Districts (1500' from edge of R/W)	0	1	0	1
Rebuild T/L	0	1	0	1
Parallel T/L	0	0	0	0
New T/L	0	0	0	0
Natural				
Natural Forests (Acres)	115.2	107.5	109.0	101.2
Rebuild T/L	15.36	18.22	15.80	18.56
Parallel T/L	49.76	49.76	49.18	49.18
New T/L	50.08	39.52	44.02	33.46
Stream/River Crossings	50	49	51	50
Rebuild T/L	9	16	9	16
Parallel T/L	22	22	22	22
New T/L	19	11	20	12
Wetland Areas (Acres)	0.0	0.0	0.0	0.0
Rebuild T/L	-	-	-	-
Parallel T/L	-	-	-	-
New T/L	-	-	-	-
Floodplain Areas (Acres)	9.4	9.4	9.4	9.4
Rebuild T/L	1.5	1.5	1.5	1.5
Parallel T/L	7.9	7.9	7.9	7.9
New T/L	0.0	0.0	0.0	0.0
Engineering				
Miles of Rebuild with Existing T/L*	7.9	12.0	7.7	11.8
Miles of Co-location with Existing T/L*	15.5	15.5	14.8	14.8
Miles of Greenfield	11.9	8.3	12.6	9.0
Total Miles	35.3	35.8	35.1	35.6
Total Project Costs	$37,154,045	$38,373,641	$36,893,565	$38,112,921

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2006-00463

INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007

REQUEST NO. 22

RESPONDING PERSON: RON MOLLENKOPF

Request 22: Provide all documents, including manufacturer guaranteed timing, that support a 345 kV 1.75 cycle relay time.

Response: The attached response to **Staff's Request 22 Exhibit A** an excerpt from the SEL-421 Relay Instruction Manual Date Code 20070223 (Feb 23, 2007). The manual shows a Published Maximum Guaranteed Timing of 0.8 cycles at 70% of reach and SIR = 1.

NOTE: Actual model power system testing was performed by SEL in Pullman, WV for the HL Spurlock 345 kV tie lines to DP&L and Cinergy. These tests proved the 421-0 relay to have a maximum response time of less than 0.75 cycles for all multiphase faults near enough to Spurlock to be considered a threat to stability.

The total relay time of 1.75 cycles that was assumed in Spurlock stability studies was actually able to be reduced to 1.25 cycles when adding in the auxiliary tripping relay time of 0.5 cycles.

A maximum relay time of 1.75 cycles for the Smith studies can be safely assumed for all critical fault conditions by the application of this relay system.

STAFF'S REQUEST 22
EXHIBIT A

Reporting Functions

High-Resolution Data

Rate: 8000 samples/second
4000 samples/second
2000 samples/second
1000 samples/second

Output Format: Binary COMTRADE

Note: Per *IEEE Standard Common Format for Transient Data Exchange (COMTRADE) for Power Systems, IEEE C37.111-1999*

Event Reports

Storage: 35 quarter-second events or 24 half-second events

Maximum Duration: Record events as long as 5 seconds

Resolution: 8- or 4-samples/cycle

Event Summary

Storage: 100 summaries

Breaker History

Storage: 128 histories

Sequential Events Recorder

Storage: 1000 entries

Trigger Elements: 250 relay elements

Processing Specifications

AC Voltage and Current Inputs

8000 samples per second, 3 dB low-pass analog filter cut-off frequency of 3000 Hz.

Digital Filtering

Full-cycle cosine and half-cycle Fourier filters after low-pass analog and digital filtering.

Protection and Control Processing

8 times per power system cycle

Synchrophasors

Maximum data rate in messages per second

IEEE C37.118 protocol: 60 (nominal 60 Hz system)
50 (nominal 50 Hz system)

SEL Fast Message protocol: 20 (nominal 60 Hz system)
10 (nominal 50 Hz system)

Control Points

32 remote bits
32 local control bits
32 latch bits in protection logic
32 latch bits in automation logic

Relay Element Pickup Ranges and Accuracies

Mho Phase Distance Elements

Zones 1-5 Impedance Reach

Setting Range

5 A Model: OFF, 0.05 to 64 Ω secondary, 0.01 Ω steps

1 A Model: OFF, 0.25 to 320 Ω secondary, 0.01 Ω steps

Sensitivity

5 A Model: 0.5 A_{p-p} secondary

1 A Model: 0.1 A_{p-p} secondary
(*Minimum sensitivity is controlled by the pickup of the supervising phase-to-phase overcurrent elements for each zone.*)

Accuracy (Steady State): ±3% of setting at line angle for SIR (source-to-line impedance ratio) < 30
±5% of setting at line angle for 30 ≤ SIR ≤ 60

Zone 1 Transient Overreach: <5% of setting plus steady-state accuracy

SEL-421-0 and SEL-421-3 Maximum Operating Time: 0.8 cycle at 70% of reach and SIR = 1

SEL-421-1 and SEL-421-2 Maximum Operating Time: 1.5 cycle at 70% of reach and SIR = 1

Mho Ground Distance Elements

Zones 1-5 Impedance Reach

Mho Element Reach

5 A Model: OFF, 0.05 to 64 Ω secondary, 0.01 Ω steps

1 A Model: OFF, 0.25 to 320 Ω secondary, 0.01 Ω steps

Sensitivity

5 A Model: 0.5 A secondary

1 A Model: 0.1 A secondary
(Minimum sensitivity is controlled by the pickup of the supervising phase and residual overcurrent elements for each zone.)

Accuracy (Steady State): ±3% of setting at line angle for SIR < 30
±5% of setting at line angle for 30 ≤ SIR ≤ 60

Zone 1 Transient Overreach: <5% of setting *plus* steady-state accuracy

SEL-421-0 and SEL-421-3 Maximum Operating Time: 0.8 cycle at 70% of reach and SIR = 1

SEL-421-1 and SEL-421-2 Maximum Operating Time: 1.5 cycle at 70% of reach and SIR = 1

Quadrilateral Ground Distance Elements

Zones 1-5 Impedance Reach

Quadrilateral Reactance Reach

5 A Model: OFF, 0.05 to 64 Ω secondary, 0.01 Ω steps

1 A Model: OFF, 0.25 to 320 Ω secondary, 0.01 Ω steps

Quadrilateral Resistance Reach

5 A Model: OFF, 0.05 to 50 Ω secondary, 0.01 Ω steps

1 A Model: OFF, 0.25 to 250 Ω secondary, 0.01 Ω steps

Sensitivity

5 A Model: 0.5 A secondary

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2006-00463
INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007
REQUEST NO. 23
RESPONDING PERSON: RON MOLLENKOPF

Request 23: For both the 9.75 cycle 345 kV breaker failure time and the 12.75 cycle 138 kV breaker failure time, show by diagram the timing of all components of the schemes and break out all margins separately. Provide similar information for the 3.75 cycle 345 kV normal clearing time and the 5.00 cycle 138 kV normal clearing time.

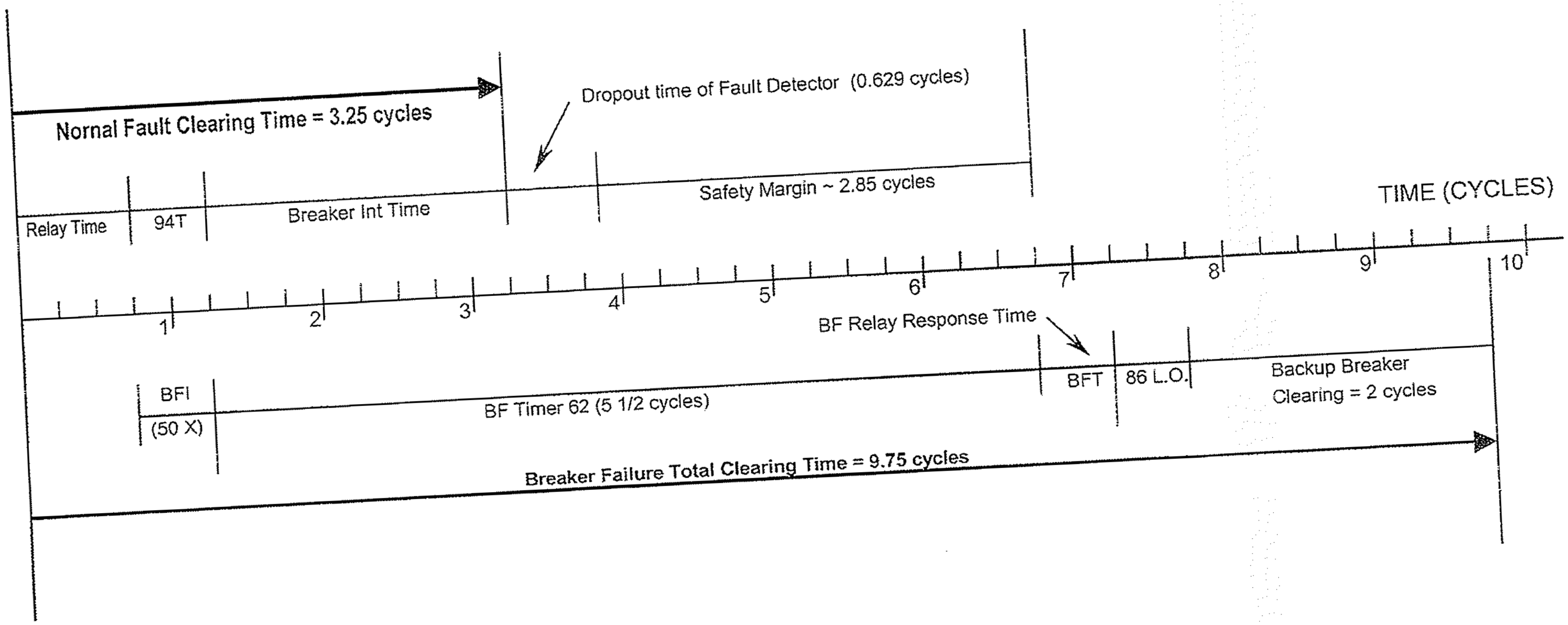
Response: The attached response to **Staff's Data Request 23 Exhibit A and Staff's Data Request 23 Exhibit B** are diagrams which show the timing of all components of the breaker failure schemes for the 345 kV and the 138 kV stations at the J.K. Smith Power Station. The normal clearing time and total clearing time for a failed breaker are shown along with all components and margins that make up the schemes.

STAFF

6/08/2007

East Kentucky Power Cooperative
Winchester, Kentucky

JK Smith Substation
345 KV Breaker Failure Chart



Notes:

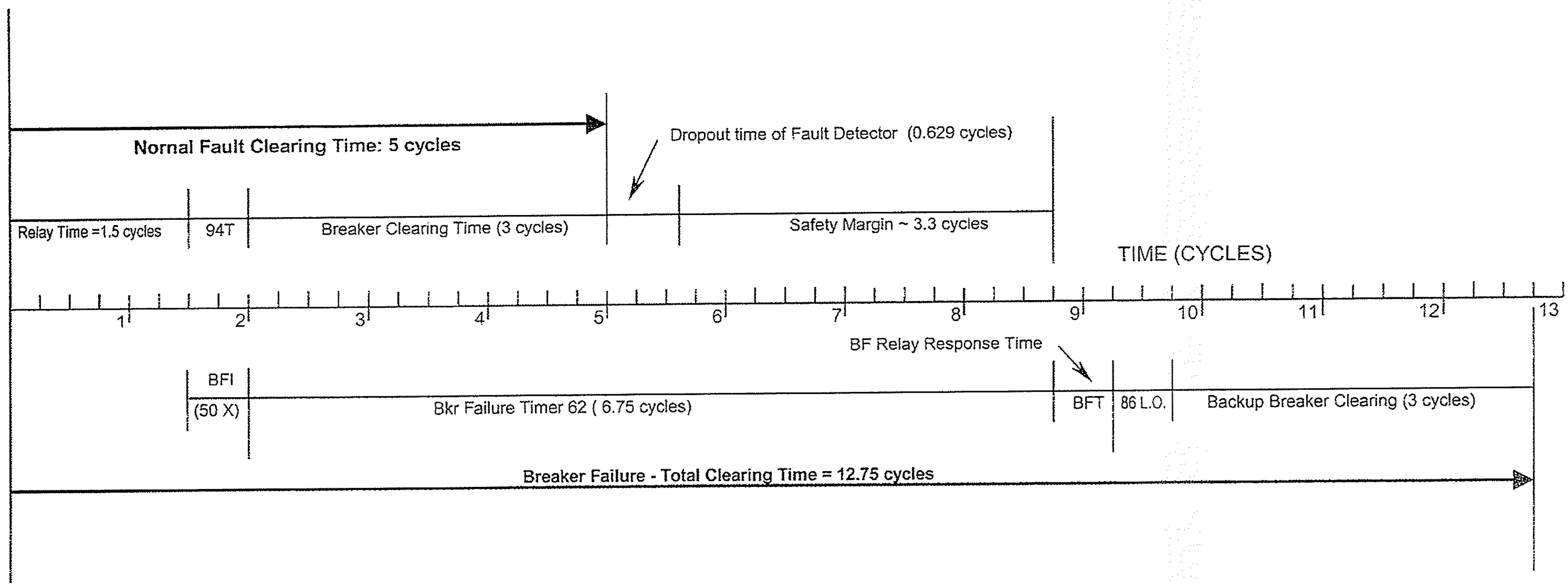
Stability Study stated normal fault clearing time at 3.75 cycle and stuck breaker clearing time at 9.75 cycles. (1.75 cycle relay)
Actual normal clearing time was reduced to 3.25 cycles and the extra 1/2 cycle was added to BF Timer for extra security margin.
Actual line relays installed have a max clearing time of 0.8 cycles worst case and < .75 cycles for severe faults. (Plus 94T Aux Time)

STAFF'S DATA REQUEST 23 EXHIBIT A

East Kentucky Power Cooperative
Winchester, Kentucky

6/08/2007

JK Smith Substation
138 KV Breaker Failure Chart



STAFF'S DATA REQUEST 23 EXHIBIT B

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2006-00463

INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007

REQUEST NO. 24

RESPONDING PERSON: DARRIN ADAMS

Request 24: Provide EKPC's 10-year transmission expansion plan.

Response: The response for this Data Request is the subject of the Applicant's Petition for Confidential Treatment and is included as **Data Request 24 Exhibit A** in that Petition filed this date.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2006-00463
INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007
REQUEST NO. 25
RESPONDING PERSON: JULIA A. TUCKER

Request 25: Show how future capacity, on-peak energy, and off-peak energy values are calculated.

Response:

EKPC Avoided Capacity Cost Calculation

The avoided capacity cost analysis is done with a spreadsheet-based model that compares expansion plans and annualized capital costs. The base expansion plan and its associated capital and fixed O&M costs are shifted out by one year from the base year, except for units that are considered committed. The difference in the net present value of annualized capital costs and fixed costs divided by the average load growth is the capital credit for the avoided capacity cost for a given base year. This analysis is done for a 10-year expansion plan beginning with a base year and moving out a year at a time. Each time the base year is incremented another year, the 10-year expansion plan is also shifted out another year and units considered committed may change as the base year is incremented. The avoided cost calculation is done for each year as the base year is shifted out. The avoided capacity cost ($/kW) is adjusted from a supply side cost to a demand side cost using the planning reserve margin of 12%, then levelized for a 10-year period. The levelized avoided capacity cost is adjusted for transmission losses to get the value at the distribution substation.

Avoided Energy Cost Calculation

The avoided energy cost analysis is based on detailed production cost model simulations using RTSim. RTSim is an hourly chronological production cost simulation model. A base case run is made along with a second run with the load reduced 50 MW each hour. The difference in the production cost for each run divided by the difference in load (50 MW) is considered the avoided energy cost. The difference in production cost is made up of a combination of variable generation costs and purchased power costs.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2006-00463
INFORMATION REQUEST RESPONSE

PUBLIC SERVICE COMMISSION DATA REQUEST DATED JULY 6, 2007
REQUEST NO. 26
RESPONDING PERSON: DARRIN ADAMS

Request 26: Revise the present value economic analysis for Alternatives 1, 2 and 3 to include energy and capacity loss analyses considering both peak and off-peak conditions through the time when CFB-3 is installed. Show the timing of major system additions and how the loss evaluation was calculated.

Response: Tables 26-1, 26-2, and 26-3 below show the updated economic analysis for the three Alternatives. This is based upon updated power flow analysis and, where available, updated scope and cost estimates for specific projects.

Table 26-1
Estimated Costs for Alternative 1

Install Date	Project Description	Planning Estimate (2006$)	Inflated Cost (Install Year $)	Present Worth (2006$)
June 2009	Construct 35.5 miles of 345 kV line from JK Smith to LGEE's Brown-Pineville double-circuit line at West Garrard using bundled 954 MCM ACSR conductor	41,750,000	47,034,000	57,062,000
June 2009	Add 345 kV Terminal Facilities at JK Smith CFB Substation for the West Garrard line	1,080,000	1,217,000	1,476,000

Table 26-1 Estimated Costs for Alternative 1				
Install Date	**Project Description**	**Planning Estimate (2006$)**	**Inflated Cost (Install Year $)**	**Present Worth (2006$)**
June 2009	Add terminal facilities at LGEE's Brown and Pineville Substations to energize the Brown-Pineville 345 kV circuit	2,160,000	2,433,000	2,952,000
June 2009	Construct a 345 kV breaker station at West Garrard with three line exits. Loop the Brown-Pineville 345 kV line through the station and terminate the new line from JK Smith	6,480,000	7,300,000	8,857,000
November 2009	Increase the terminal limits at LGEE's Pineville Substation associated with the low side of the Pineville 345-161 kV transformer to at least 2150A (600 MVA) winter emergency.	160,000	180,000	219,000
June 2010	Increase the terminal limits at LGEE's Boonesboro North associated with the Boonesboro North 138-69 kV transformer to at least 1320A (158 MVA) summer emergency.	140,000	161,000	181,000
November 2010	Increase the limits of the Ferguson South-Somerset (LGEE-EKPC) 69 kV line to at least 855A (102 MVA) winter emergency.	10,000	12,000	13,000
November 2012	Reconductor EKPC's JK Smith-Union City 138 kV line using 954 MCM ACSS conductor.	2,290,000	2,769,000	2,624,000
November 2012	Increase the terminal limits of EKPC's Powell County 138-69 kV transformer to 147 MVA winter emergency.	110,000	133,000	126,000
June 2013	Increase the terminal limits of the Union City-Lake Reba Tap 138 kV line (EKPC-LGEE) to at least 301 MVA summer emergency.	10,000	12,000	11,000
June 2014	Increase the limits of LGEE's Alcalde-Elihu 161 kV line to at least 950A (265 MVA) summer emergency and 1220A (340 MVA) winter emergency.	1,400,000	1,775,000	1,419,000

Table 26-1 Estimated Costs for Alternative 1				
Install Date	**Project Description**	**Planning Estimate (2006$)**	**Inflated Cost (Install Year $)**	**Present Worth (2006$)**
June 2014	Increase the limits of LGEE's Artemus 161-69 kV transformer to at least 65 MVA summer emergency.	1,100,000	1,395,000	1,115,000
June 2014	Increase the terminal limits at LGEE's Boonesboro North associated with the Boonesboro North 138-69 kV transformer to at least 163 MVA summer emergency.	30,000	38,000	30,000
June 2014	Increase the terminal limits at LGEE's Boonesboro North associated with the Boonesboro North-Winchester Water Works 69 kV circuit to at least 1245A (149 MVA) summer emergency.	110,000	139,000	111,000
November 2014	Replace EKPC's Powell County 138-69 kV, 100 MVA transformer with a 140 MVA transformer.	1,700,000	2,155,000	1,723,000
June 2015	Increase the limits of LGEE's Pineville 161-69 kV transformer #2 to at least 139 MVA summer emergency.	2,120,000	2,752,000	2,016,000
June 2015	Reconductor EKPC's Union City-Lake Reba Tap 138 kV line using 954 MCM ACSS conductor.	290,000	376,000	276,000
November 2015	Increase the limits of LGEE's Artemus 161-69 kV transformer and the Artemus-Barbourville City 69 kV line to at least 74 MVA winter emergency.	110,000	143,000	105,000
November 2015	Increase the limits of LGEE's Elihu-Ferguson South 69 kV line to at least 118 MVA winter emergency.	10,000	13,000	10,000
November 2016	Reconductor EKPC's Dale-Fawkes 138 kV line using 954 MCM ACSS conductor.	1,850,000	2,459,000	1,649,000
November 2022	Construct 48 miles of 345 kV line from JK Smith to Tyner using bundled 954 MCM ACSR conductor	56,445,000	84,420,000	31,833,000
November 2022	Add 345 kV Terminal Facilities at JK Smith CFB Substation for the Tyner line.	1,080,000	1,615,000	609,000
November 2022	Install a 345-161 kV, 450 MVA transformer at Tyner.	4,300,000	6,431,000	2.425.000

Table 26-1 Estimated Costs for Alternative 1				
Install Date	**Project Description**	**Planning Estimate (2006$)**	**Inflated Cost (Install Year $)**	**Present Worth (2006$)**
November 2022	Replace the Tyner 161-69 kV, 65 MVA transformer with a 140 MVA transformer.	1,700,000	2,543,000	959,000
	Total	$126,435,000	$167,506,000	$117,798,000

Table 26-2 Estimated Costs for Alternative 2				
Install Date	**Project Description**	**Planning Estimate (2006$)**	**Inflated Cost (Install Year $)**	**Present Worth (2006$)**
June 2009	Construct 48 miles of 345 kV line from JK Smith to Tyner using bundled 954 MCM ACSR conductor	56,445,000	63,589,000	77,146,000
June 2009	Add 345 kV Terminal Facilities at JK Smith CFB Substation for the Tyner line.	1,080,000	1,217,000	1,476,000
June 2009	Install a 345-161 kV, 450 MVA transformer at Tyner.	4,300,000	4,844,000	5,877,000
June 2009	Replace the Tyner 161-69 kV, 65 MVA transformer with a 140 MVA transformer.	1,700,000	1,915,000	2,323,000
June 2009	Increase the terminal limits of LGEE's Delvinta-Hyden Tap 161 kV line section to at least 690A (192 MVA) summer emergency and 905A (252 MVA) winter emergency.	40,000	45,000	52,000
June 2009	Increase the terminal limits of LGEE's Hopewell-Sweet Hollow 69 kV line section to at least 615A (73 MVA) summer emergency and 725A (87 MVA) winter emergency.	85,000	96,000	110,000
June 2009	Reconductor the Fawkes Tap-Fawkes LGEE 138 kV line using bundled 556 MCM ACSR conductor and replace the limiting terminal equipment at Fawkes LGEE.	150,000	169,000	194,000
November 2009	Increase the terminal limits of the Fawkes EKPC-Fawkes LGEE 138 kV line to at least 1490A (356 MVA) winter emergency.	30,000	34,000	39,000

Table 26-2 Estimated Costs for Alternative 2				
Install Date	**Project Description**	**Planning Estimate (2006$)**	**Inflated Cost (Install Year $)**	**Present Worth (2006$)**
November 2009	Increase the limits of AEP's Leslie-Hazard 69 kV line to at least 520A (62 MVA) winter emergency rating.	900,000	1,014,000	1,162,000
November 2009	Increase the terminal limits of AEP's Morehead-Hayward 69 kV line to at least 475A (57 MVA) winter emergency.	110,000	127,000	134,000
June 2010	Increase the terminal limits at LGEE's Boonesboro North associated with the Boonesboro North 138-69 kV transformer to at least 1320A (158 MVA) summer emergency.	140,000	161,000	181,000
November 2011	Replace the 1200A metering CTs at the Fawkes EKPC Substation associated with the Fawkes EKPC-Fawkes Tap 138 kV line.	30,000	35,000	34,000
June 2012	Increase the terminal limits at LGEE's Boonesboro North associated with the Boonesboro North-Winchester Water Works 69 kV circuit to at least 1245A (149 MVA) summer emergency.	110,000	133,000	126,000
June 2014	Install a 138 kV, 5% series reactor at Dale in the Dale-Boonesboro North 138 kV line	645,000	818,000	654,000
June 2014	Reconductor EKPC's JK Smith-Union City 138 kV line using 954 MCM ACSS conductor.	2,290,000	2,903,000	2,321,000
June 2014	Reconductor EKPC's Dale-Fawkes 138 kV line using 954 MCM ACSS conductor.	1,850,000	2,345,000	1,875,000
November 2014	Increase the terminal limits of EKPC's Powell County 138-69 kV transformer to 147 MVA winter emergency.	110,000	139,000	105,000
June 2015	Increase the terminal limits of LGEE's Clark County 138-69 kV transformer to 1320A (157 MVA) summer emergency.	110,000	143,000	99,000
November 2015	Replace EKPC's Powell County 138-69 kV, 100 MVA transformer with a 140 MVA transformer.	1,700,000	2,207,000	1,527,000

Table 26-2
Estimated Costs for Alternative 2

Install Date	Project Description	Planning Estimate (2006$)	Inflated Cost (Install Year $)	Present Worth (2006$)
November 2015	Increase the terminal limits of the Fawkes EKPC-Fawkes LGEE 138 kV line at Fawkes LGEE to at least 1760A (421 MVA) winter emergency.	160,000	208,000	144,000
November 2016	Reconductor EKPC's Union City-Lake Reba Tap 138 kV line using 954 MCM ACSS conductor.	300,000	399,000	267,000
November 2022	Construct 35.5 miles of 345 kV line from JK Smith to LGEE's Brown-Pineville double-circuit line at West Garrard using bundled 954 MCM ACSR conductor	41,750,000	62,442,000	23,545,000
November 2022	Add 345 kV Terminal Facilities at JK Smith CFB Substation for the West Garrard line	1,080,000	1,615,000	609,000
November 2022	Add terminal facilities at LGEE's Brown and Pineville Substations to energize the Brown-Pineville 345 kV circuit	2,160,000	3,231,000	1,218,000
November 2022	Construct a 345 kV breaker station at West Garrard with three line exits. Loop the Brown-Pineville 345 kV line through the station and terminate the new line from JK Smith	6,480,000	9,692,000	3,654,000
November 2022	Increase the limits of LGEE's Alcalde-Elihu 161 kV line to at least 950A (265 MVA) summer emergency and 1220A (340 MVA) winter emergency.	1,400,000	2,094,000	790,000
	Total	$125,155,000	$161,614,000	$125,661,000

Table 26-3
Estimated Costs for Alternative 3

Install Date	Project Description	Planning Estimate (2006$)	Inflated Cost (Install Year $)	Present Worth (2006$)
June 2009	Construct 48 miles of 345 kV line from JK Smith to Tyner using bundled 954 MCM ACSR conductor	56,445,000	63,589,000	77,146,000

Table 26-3 Estimated Costs for Alternative 3				
Install Date	**Project Description**	**Planning Estimate (2006$)**	**Inflated Cost (Install Year $)**	**Present Worth (2006$)**
June 2009	Add 345 kV Terminal Facilities at JK Smith CFB Substation for the Tyner line.	1,080,000	1,217,000	1,476,000
June 2009	Install a 345-161 kV, 450 MVA transformer at Tyner.	4,300,000	4,844,000	5,877,000
June 2009	Replace the Tyner 161-69 kV, 65 MVA transformer with a 140 MVA transformer.	1,700,000	1,915,000	2,323,000
June 2009	Construct 17.9 miles of 138 kV line from J.K. Smith to LGEE's Spencer Road using 954 MCM ACSR conductor.	7,160,000	8,066,000	9,786,000
June 2009	Add 138 kV terminal facilities at the J.K. Smith CT Substation for the Spencer Road Line.	270,000	304,000	369,000
June 2009	Add 138 kV terminal facilities at LGEE's Spencer Road Substation for the J.K. Smith Line.	270,000	304,000	369,000
June 2009	Reconductor LGEE's Clark County-Sylvania-Parker Seal 69 kV line (0.8 miles) using 1272 MCM ACSR conductor.	150,000	169,000	194,000
June 2009	Increase the terminal limits of the Clark County-Sylvania 69 kV line to the summer emergency conductor capability.	110,000	124,000	142,000
June 2009	Increase the terminal limits of LGEE's Hopewell-Sweet Hollow 69 kV line section to at least 615A (73 MVA) summer emergency and 725A (87 MVA) winter emergency.	85,000	96,000	110,000
November 2009	Increase the limits of AEP's Leslie-Hazard 69 kV line to at least 520A (62 MVA) winter emergency rating.	900,000	1,014,000	1,162,000
November 2009	Increase the terminal limits of AEP's Morehead-Hayward 69 kV line to at least 475A (57 MVA) winter emergency.	110,000	127,000	134,000
November 2009	Increase the terminal limits of LGEE's Delvinta-Hyden Tap 161 kV line section to at least 625A (174 MVA) summer emergency and 815A (227 MVA) winter emergency.	40,000	45,000	52,000

Table 26-3 Estimated Costs for Alternative 3				
Install Date	**Project Description**	**Planning Estimate (2006$)**	**Inflated Cost (Install Year $)**	**Present Worth (2006$)**
June 2010	Increase the terminal limits of LGEE's Clark County 138-69 kV transformer to 1320A (157 MVA) summer emergency.	110,000	127,000	134,000
June 2012	Reconductor LGEE's Spencer Road-A.O. Smith Tap-Camargo 69 kV line (2.8 miles) using 556 MCM ACSR conductor.	400,000	484,000	433,000
June 2010	Reconductor the Fawkes Tap-Fawkes LGEE 138 kV line using bundled 556 MCM ACSR conductor.	100,000	115,000	122,000
November 2014	Replace the 1200A limiting terminal equipment at the Fawkes LGEE Substation associated with the Fawkes Tap-Fawkes LGEE 138 kV line.	20,000	25,000	19,000
November 2014	Replace the 1200A metering CTs at the Fawkes EKPC Substation associated with the Fawkes EKPC-Fawkes Tap 138 kV line.	30,000	38,000	29,000
November 2022	Construct 35.5 miles of 345 kV line from JK Smith to LGEE's Brown-Pineville double-circuit line at West Garrard using bundled 954 MCM ACSR conductor	41,750,000	62,442,000	23,545,000
November 2022	Add 345 kV Terminal Facilities at JK Smith CFB Substation for the West Garrard line	1,080,000	1,615,000	609,000
November 2022	Add terminal facilities at LGEE's Brown and Pineville Substations to energize the Brown-Pineville 345 kV circuit	2,160,000	3,231,000	1,218,000
November 2022	Construct a 345 kV breaker station at West Garrard with three line exits. Loop the Brown-Pineville 345 kV line through the station and terminate the new line from JK Smith	6,480,000	9,692,000	3,654,000
November 2022	Increase the limits of LGEE's Alcalde-Elihu 161 kV line to at least 950A (265 MVA) summer emergency and 1220A (340 MVA) winter emergency.	1,400,000	2,094,000	790,000
	Total	$125,895,000	$161,419,000	$129,218,000

Losses were evaluated for the three alternatives to incorporate into the economic comparison. Power flow analysis was used to identify the peak (100% load), shoulder peak (80% load), and off-peak (50% load) losses for the period from 2009 through 2021. After 2009, the plans become similar since all three will include both a 345 kV line from J.K. Smith to West Garrard and from J.K. Smith to Tyner. Also, the calculations of losses for later years are determined by modeling projected transmission and generation plans and extrapolating from power flow models that are available at the time, which were for the years 2010 and 2015. Therefore, the projections become much less certain in the later years. For these reasons, the economic calculation of the loss differential was stopped at 2021.

Projected energy costs for both peak and off-peak periods were developed based upon EKPC's future power supply plans and production costing information. It was assumed that two-thirds of the hours in a year are peak/shoulder-peak hours (5870 hours) and one-third of the hours are off-peak hours (2890 hours). Hourly load forecasts for 2008 were used to identify the number of peak hours versus shoulder-peak hours. This load date indicates that approximately 55 hours are in the range of 85% to 100% of the peak value. Then, 5815 hours are considered shoulder-peak hours, which ranges from 85% of peak to 50% of peak. The remaining 2890 off-peak hours consist of load levels from 50% of peak to 32% of peak.

A loss factor was then estimated to compensate for the use of power flows based upon only three load levels (100%, 80%, and 50%) to calculate losses for loads that cover a range of load levels over the course of an entire year. For instance, the losses at peak are based on a 100% load level in the power flow model, but the 55 peak hours cover a load range from 100% to 85%.

Therefore, for the majority of the 55 hours the actual expected losses will be lower than those calculated at 100% load. A loss factor of 0.8 was estimated to provide values that should be approximately in the middle of each range.

The estimated cost of energy losses was calculated as follows for each Alternative:

(Peak case losses x 55 hours x 0.8 x on-peak energy cost) + (80% load case losses x 5815 hours x 0.8 x on-peak energy cost) + (50% load case losses x 2890 hours x 0.8 x off-peak energy cost)

The cost of additional generation capacity required due to incremental losses is calculated by multiplying the projected annual cost of additional capacity (on a $ per MW basis) with the projected peak losses each year. For example, if the projected cost of capacity is $50,000 per MW, and the peak loss value determined from the peak power flow model is 5 MW, the cost of additional capacity required due to these losses would be $250,000.

The calculated values of incremental energy cost and capacity cost due to losses were summed together to determine the total cost of incremental losses for each Alternative in each year from 2009 through 2021. A total present value of incremental losses over this period was then calculated.

As mentioned in this discussion, all loss calculations are performed on an incremental basis -- this is done by determining which Alternative provides the lowest level of losses in each year. The incremental value of the losses provided for the other two Alternatives is then calculated by comparison.

Table 26-4 below shows the updated comparison of costs when the present values of incremental transmission losses are included with the present values of construction provided in Tables 26-1, 26-2, and 26-3 above for the three Alternatives.

Table 26-4

Comparison of Present Value Costs of Alternatives 1, 2, and 3

Alternative	Present Value of Construction Costs (2006$)	Present Value of Incremental Losses (2006$)	Total Present Value (2006$)
1	$117,798,000	$13,052,000	$130,850,000
2	$125,661,000	$5,255,000	$130,916,000
3	$129,218,000	$0	$129,218,000

EKPC's analysis indicates that the 30-year present values of the three Alternatives are within $1.7 million of each other, which is slightly more than 1% of the total present value cost of any of the three Alternatives.

Respectfully submitted,

SHERMAN GOODPASTER III
P. O. BOX 707
WINCHESTER, KY 40392-0707
(859) 744-4812
ATTORNEYS FOR EAST KENTUCKY
POWER COOPERATIVE, INC.

CERTIFICATE OF SERVICE

Enclosed are an original and five (5) copies of East Kentucky Power Cooperative, Inc.'s Responses to Commission Staff's First Data Request in the above-styled case.

SHERMAN GOODPASTER III

H:Legal/PSC/2006-00463-responses to PSC First Data Req..doc