KU

a PPL company

Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40602

RECEIVED
JAN 14 2011
PUBLIC SERVICE COMMISSION

Kentucky Utilities Company
State Regulation and Rates
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Rick E. Lovekamp
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January 14, 2011

RE: ***APPLICATION OF KENTUCKY UTILITIES COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF TRANSMISSION FACILITIES IN MCCRACKEN COUNTY, KENTUCKY - CASE NO. 2010-00164***

Dear Mr. DeRouen:

Please find enclosed and accept for filing the original and ten (10) copies of the Response of Kentucky Utilities Company to the First Information Request of Commission Staff dated January 7, 2011, in the above-referenced matter.

Also enclosed are an original and ten (10) copies of a Petition for Confidential Protection regarding information provided in response to Question No. 1 and Question No. 15.

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

Sincerely,

Rick E. Lovekamp

Enclosures

cc: Parties of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY	)	CASE NO.
FOR THE CONSTRUCTION OF	)	2010-00164
TRANSMISSION FACILITIES IN MCCRACKEN	)	
COUNTY, KENTUCKY	)	

RESPONSE OF
KENTUCKY UTILITIES COMPANY
TO THE
COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION
DATED JANUARY 7, 2011

FILED: January 14, 2011

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Edwin R. Staton**, being duly sworn, deposes and says that he is Director - Transmission for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Edwin R. Staton

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14th day of January 2011.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept. 22, 2014

VERIFICATION

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

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar
Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14th day of January 2011.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 22, 2014

KENTUCKY UTILITIES COMPANY

CASE NO. 2010-00164

Response to Commission Staff's First Data Request
Dated January 7, 2011

Question No. 1

Witness: Edwin R. Staton

Q-1. Provide a one-line diagram for the transmission area surrounding the proposed line.

A-1. The one-line diagram of the transmission area is confidential and will be the subject of a Petition for Confidential Protection that will be filed at the Public Service Commission. It has already been provided to P&D pursuant to a Confidentiality Agreement.

KENTUCKY UTILITIES COMPANY

CASE NO. 2010-00164

Response to Commission Staff's First Data Request
Dated January 7, 2011

Question No. 2

Witness: Edwin R. Staton

Q-2. Provide the design and reliability criteria used for the transmission system power flow studies.

A-2. Please see the attached E.ON U.S. Transmission Planning Guidelines dated August 14, 2009. (As of November 1, 2010 PPL acquired E.ON U.S., LG&E and KU continue to operate under the E.ON U.S. Transmission Planning Guidelines).

E.ON U.S.

Transmission Strategy and Planning

TRANSMISSION SYSTEM PLANNING GUIDELINES

Effective Date: August 14, 2009

Prepared by:
Tom Seeley, Group Leader - Transmission Planning

Approved by:

Keith Yocum | **Date:** 8/13/09
Keith Yocum, Manger - Transmission Strategy & Planning

Ed Staton | **Date:** 8/13/09
Ed Staton, Director - Transmission

Revision History

Date	Description
June 6, 1998	Initial LGEE document to establish guidelines applicable to both LG&E and KU
March 11, 2005	Expanded Table 1
March 1, 2007	Added NERC Categories to Table 1 and expanded
May 7, 2007	Better quantified thermal overload and voltage violations and added Section 4 – Impacted Facilities
September 11, 2007	Added section describing how Guidelines exceed NERC requirements
May 1, 2008	Added effective date, signatures, Revision History, Contingency Selection criteria, updated Tables 2 & 3 and updated certain references
July 1, 2008	Updated performance requirements and incorporated SOL Methodology
August 14, 2009	Added statement reiterating comparable treatment of service requests per FERC Order.

Purpose

This document describes the guidelines used for developing the E.ON U.S. (E.ON) Transmission Expansion Plan in accordance with the requirements of North American Electric Reliability Corporation's (NERC) Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0 and SERC Reliability Corporation (SERC) Supplements to those standards.

1. Overview

The primary purpose of E.ON's transmission system is to reliably transmit electrical energy from Designated Network Resources to Network Loads. Interconnections to other transmission systems have been established to increase the reliability of E.ON's transmission system and to provide access to emergency generation sources for Network Customers.

E.ON subscribes to and designs its transmission system to conform to the fundamental characteristics of a reliable interconnected Bulk Electric System (BES) recommended by NERC. Additionally, E.ON is a member of SERC Reliability Corporation (SERC) and subscribes to and designs its transmission system to comply with the reliability principles and responsibilities set forth in the SERC Supplements.

The Federal Energy Regulatory Commission (FERC) requires all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have a non-discriminatory Open Access Transmission Tariff (OATT). E.ON's Operating Companies (KU/LG&E) have an OATT on file with FERC to provide Point-To-Point transmission service and Network Integration Transmission Service. E.ON is committed to provide the same reliability and priority of service to Long-Term Firm Point-To-Point Transmission Service with a contract period of five or more years as it does for its Network Customers. E.ON is committed to ensuring that customers with comparable service requests are treated comparably for transmission planning purposes.

The American National Standards Institute (ANSI) and The Institute of Electrical and Electronic Engineers, Inc. (IEEE) publish standards for power system equipment design and application. E.ON incorporates ANSI and IEEE standards in the design and application of equipment utilized in the transmission system.

2. NERC and SERC Reliability Standards Compliance

NERC Reliability Standards TPL-001 through TPL-004 outline the fundamental requirements for planning reliable interconnected Bulk Electric Systems and the required actions or system performance necessary for compliance. The Regions, sub-regions, power pools, and their members have the responsibility to develop their own appropriate or more detailed planning criteria and guides based on the NERC Reliability Standards.

E.ON has developed and adopted the following Transmission Reliability Planning Criteria that exceed the requirements of the NERC Reliability Standards and SERC Supplements. E.ON applies system performance criteria consistent with Category B contingencies (TPL-002) to the following contingencies, without manual system adjustments:

- The following Category C (TPL-003) contingencies:
  - A simultaneous outage of two generators
  - A simultaneous outage of one generator and one transmission circuit
  - A simultaneous outage of one generator and one transmission transformer
- The outage of one transmission circuit or transmission transformer with one generator outage and replacement generation maximized as specified in section 5.7.

SERC Supplement "Transmission System Performance" was prepared to outline SERC's interpretation and to clarify SERC's expectations of members with regard to the NERC Reliability Standards TPL-001 through TPL-004. The SERC Supplement contains the standards that transmission providers are expected to adhere to in their simulated testing and system performance evaluations. E.ON's Transmission Reliability Planning Criteria meet or exceed the requirements of the SERC Supplement.

3. Transmission Planning Process

E.ON assesses the performance of its transmission system annually. The assessments include steady state simulations and, as appropriate, dynamic simulations. Steady state simulations of contingencies with a Required Performance Level of 1 or 2 (see Table 1) will be performed annually. Other components of the assessment must be supported by studies or simulations that have been performed within three years.

The steady state simulations evaluate the adequacy of the transmission system to provide Network Integration Transmission Service using summer and winter peak models. Transmission constraints that may occur during shoulder and off-peak conditions will be managed in the Planning Horizon via the establishment of System Operating Limits. Studies for Generator Interconnections will also utilize other seasonal and light load models, as appropriate.

The dynamic simulations will be performed on summer peak and light load models. The summer peak models are used for angular and voltage stability and the light load models are used primarily for angular stability.

The goals of the Transmission Planning Process are to:

- Develop the Transmission Expansion Plan
- Support the Independent Transmission Organization's (ITO) evaluation of Generator Interconnection and Transmission Service requests
- Evaluate Transmission to Transmission Interconnection requests
- Indentify boundary conditions in the planning studies

4. Base Case Development

Power flow, stability and short circuit models are developed annually to support the planning process.

Power Flow
Transmission base cases (Base Case(s)) for steady state analysis are developed on an annual basis to reflect the most current information and assumptions available concerning the modeling of future years' system load level and load distribution, generation and transmission expansion, firm transmission service obligations and representations of similar assumption for other systems.

Base Case models are developed for each of the summer and winter peak periods included in the most recent NERC Multi-Regional Modeling Working Group (MMWG) Base Case Series. Additionally, a Long-Term (10+ year) winter peak Base Case is developed utilizing the last winter peak case in the series. Each Base Case contains a detailed representation of the E.ON and East Kentucky Power Cooperative (EKPC) control areas from 69 kV through 500 kV. The NERC representation of all fist-tier systems in the NERC models is incorporated into the Base Cases. Second-tier systems and beyond are grouped considering geographic location and electrical interconnections and then equivalences are developed.

The generation in the E.ON control area is economically dispatched. The transmission level voltage at the power plants will be regulated in the Base Case models as shown in Table 2.

Network Customers provide forecasts of the Network Load levels to include in the models. E.ON's load level is based on the Company 50/50 forecast with all interruptible or curtailable loads being served. The anticipated transmission configuration is based upon the most recent Transmission Expansion Plan submitted to the ITO. Planned maintenance outages are not modeled. Existing and planned outages of generators and transmission facilities of more than three months in duration that are likely to occur at the time of peak of the Base Case season will be simulated.

Stability
The models available in the most recent NERC MMWG Base Case Series are used for stability simulations. The E.ON Bulk Electric System is reviewed and modified, if necessary, to be consistent with the Transmission Expansion Plan.

5. Reliability Planning Criteria

The evaluation of power flows and steady state voltages are the normal means by which the transmission planner shall determine satisfactory performance of the transmission system. Power flows and system voltages are evaluated for normal conditions and post-contingency conditions.

E.ON's Transmission Reliability Planning Criteria consists of a list of credible contingencies and associated performance requirements utilized in assessing and testing its transmission system.

5.1 Performance Requirements

E.ON has established the following levels of performance consistent with the requirements of the NERC Reliability Standards and the perceived risk. Levels 1 and 2 maintain Interconnection Integrity and serve the entire customer demand. Levels 3 and 4 allow Non-Consequential Load Loss in order to maintain Interconnection Integrity. Construction and upgrades necessary to meet the requirements of Performance Levels 1-4 will be identified and incorporated into the Transmission Expansion Plan. Special Protection Schemes will not be used to delay necessary construction and upgrades. Mitigation Plans will be developed if construction and upgrades cannot be completed when required. E.ON does not have any established normal (pre-contingency) operating procedures and therefore none are in place when simulations are performed. See Table 1 for the required performance levels associated with each of the NERC contingency categories.

<u>Level 1</u>
Power flows will not exceed the normal thermal limit
System voltages shall be within the limits specified for normal conditions
Network Loads are served from normal delivery points

<u>Level 2</u>
Power flows shall not exceed the emergency thermal limit
Transmission voltages at Generator Connections shall be greater than specified in Table 3
System voltages shall be within the limits specified for contingency conditions
Network Loads that are removed from service due to the fault clearing action can be reconnected using <u>Load Restoration and Switching</u> procedures.

<u>Level 3</u>
Transmission voltages at Generator Connections shall be greater than specified in Table 3
Bulk Electric System voltages shall be greater than 0.80 p.u.
Subsequent tripping of Bulk Electric System facilities with power flows in excess of the emergency thermal limit shall not cause

1) Low voltage at generators connected to the Bulk Electric System
2) Power flows in excess of the emergency thermal limit on two or more Bulk Electric System facilities
3) Non-Consequential Load Loss in excess of 10 percent of the forecasted seasonal peak load

<u>Level 4</u>
Following generation redispatch or shedding of 5 percent of forecasted seasonal peak load

1) Bulk Electric System power flows shall not exceed the emergency thermal limit
2) System voltages shall be within the limits specified for contingency conditions
3) Transmission voltages at Generator Connections shall be greater than specified in Table 3

Level 5
If the analysis concludes that there are cascading outages caused by the occurrence of the event, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.

5.2 Thermal Facility Limits

E.ON has established normal and emergency thermal limits (MVA) for each facility based upon its established ratings methodology. The emergency thermal limits used in the planning process are long-term limits the facility can withstand through the daily demand cycle without significant loss of equipment life.

A facility will be overloaded when the MVA flow, rounded to two decimal places, exceeds the applicable rating. The recorded circuit flow will be the maximum MVA flow of either end. The recorded transformer flow will be the "design output" flow, GSU flows will be measured at the HV side, step-down transformers will be measured at the LV side and system tie transformers will be measured on the side where the flow exits the transformer.

5.3 System Voltage Limits

A voltage violation will occur when the percent nominal voltage, rounded to two decimal places, is outside the applicable criteria.

A transmission voltage of 94 percent of the nominal value is the minimum acceptable for normal load service and should be maintained at all load serving buses with normal generation and normal transmission system conditions. The voltage at any 500 kV system bus should not exceed 110 percent of the nominal value and any other transmission bus should not exceed 105 percent of the nominal value.

A transmission voltage of 90 percent of the nominal value is the minimum acceptable for contingency load service and should be maintained at all load serving buses during any transmission system contingency or generation and transmission system contingency.

Generators and plant auxiliary systems are generally designed to operate within +/- 5 percent of the nameplate or nominal voltage. Table 3 shows the minimum acceptable transmission level voltage at each generating unit connection to maintain generator voltage and auxiliary bus voltage above 95 percent of nominal with the unit operating at maximum MW and MVAR output. Only on-line generators are applicable to the analysis.

5.4 Voltage Stability Limits

The methods used for assessing voltage stability are V-Q and P-V analysis. Bulk Electric System buses with the lowest voltage or the highest voltage deviation are candidates for voltage stability analysis.

Voltage stability analysis will be performed via V-Q analysis if the BES contingency simulated in the steady-state analysis causes a BES voltage deviation greater than 8 percent or a post-contingency, pre-capacitor switching BES voltage less than 85 percent.

V-Q analysis quantifies the Reactive Power Margin at the bus. The Reactive Power Margin is defined as the value of the condenser output at the voltage collapse point on the V-Q curve where dQ/dV = 0. The voltage collapse point shall not occur above 0.85 p.u. voltage.

P-V analysis quantifies the load level that will cause voltage collapse, the point on the P-V curve where dV/dP = -1. The study load level must be less than the maximum load operating point determined at

1) 5 percent below the load at the collapse point on the P-V curve for simulations of contingencies with a Required Performance Level of 1 or 2 (see Table 1), or
2) 2.5 percent below the load at the collapse point on the P-V curve for simulations of contingencies with a Required Performance Level of 3 or 4.

5.5 Transient Stability Limits

All generators must remain stable. The Bulk Electric System voltage at the generator interconnections must recover to 0.9 p.u. voltage within 1.0 seconds after the fault is cleared. All machine rotor angle oscillations will be positively damped.

5.6 Credible Contingency Selection

Generator Contingency Selection
The Single Generator Contingency analysis will simulate an outage of the largest generator at each transmission bus. The Double Generator Contingency analysis will simulate an outage of the two largest generators at each plant and at each transmission bus. Smaller generators or combinations thereof will produce less severe results.

Transmission Contingency Selection
Category B analyses will simulate each Branch Contingency and each Multiple Branch Contingency in E.ON, each Branch Contingency in EKPC that would cause an E.ON transmission flow increase greater than 10 percent of the element Emergency rating and each 100 kV or higher Branch Contingency in other first-tier utilities that would cause an E.ON flow increase greater than 10% of the element Emergency rating. Category C2 and C3 contingencies will be tested by simulating all combinations of the Single Generator Contingencies and all Category B Transmission Contingencies. All Category C bus and

double circuit (>1 mile) contingencies and all Category D contingencies in the E.ON system will be simulated.

Branch Contingency
A Branch is a connection between buses with 3 or more network connections. When a branch has multiple segments with multiple loads and/or radial connections, the outage of the segments on each end of the branch will be simulated individually to create the worst case Branch contingency.

Multiple Branch Contingency

A single fault may outage multiple transmission components and Branches in the common zone of relay protection. Reclosure of the non-faulted components will be evaluated but reclosing is not required if violations occur as a result of the post-fault restoration. Procedures should be developed and documented if the component is not to be reclosed.

High Voltage Direct Current (HVDC) Contingencies
E.ON does not operate any HVDC facilities and is not aware of any HVDC within first-tier utilities. Therefore, E.ON does not evaluate HVDC contingencies.

5.7 Other Modeling Considerations

Generation Re-dispatch
Replacement generation required to offset unit outages should be simulated from the most restrictive of internal sources, Midwest Independent System Operator (MISO), and/or Tennessee Valley Authority (TVA) and /or PJM.

In addition to unit outages, the Assessment also includes contingencies that consist of a unit outage coupled with maximum output from the plant that is replacing the lost generation.

When simulating a maximum plant output scenario, the lost generation will be replaced at another plant and, when necessary, additional reductions will be prorated across all on-line units to achieve maximum output. Maximum plant output scenarios are only simulated for outages of units of 200 MW or greater and only at plants that have sufficient excess capacity to absorb the outaged unit..

Load Restoration and Switching
Post-fault conditions and conditions after load restoration and/or switching 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, but load should not be taken off-line to perform switching. Post-contingency operator-initiated actions may be simulated to reduce the flow through transformers or increase voltages but not to reduce line flows.

Transmission Capacitor Switching
Transmission capacitor status (on/off) should be simulated consistent with automatic voltage control (on/off) settings and operating practice during normal transmission system conditions. Capacitor switching should not be simulated to eliminate voltage violations that result from a contingency unless the automatic voltage control would cause the capacitor to operate.

Off-Peak Voltage Control
Transmission system changes to manage Off-Peak voltages will be identified and evaluated using operation data. Seasonal adjustment of fixed taps on transmission transformers should not be required to control voltages within the acceptable ranges. Switching Extra High Voltage (EHV) (345 kV and up in E.ON) system facilities out of service to reduce off-peak voltages is undesirable.

Voltage Fluctuations
E.ON limits voltage fluctuation due to customer load variations and transmission capacitor switching to a maximum of 3 percent during normal transmission conditions and 6 percent during single transmission contingencies. These maximum values apply if the fluctuation occurs less frequently than once per hour. If more frequent, the maximum allowable voltage fluctuation is reduced per Figure A.1 – Flicker tolerance curve from IEEE standard 141-1933/IEEE Std 519-1992 published in IEEE Std 1453-2004. The maximum normal and contingency fluctuations are limited to the "Borderline of Visibility of Flicker" and the "Borderline of Irritation" curves, respectively.

6. Impacted Facilities

Generator Interconnections, Transmission to Transmission Interconnections, Network Integration Transmission Service, and Long-Term (1 year or longer) Firm Point-To-Point Requests require studies to identify facilities that are impacted. The following minimum requirements are used to identify Impacted Facilities:

- the flow increases by 1.00 percent or more
- the voltage decreases by 0.50 percent or more
- the short circuit current increases by 5.00 percent or more

Impacted Facilities that are identified with pre-existing criteria violations (simulations on base case models) will be evaluated to determine the upgrade required to mitigate the pre-existing violation. Such upgrades and associated ratings will be used to determine if additional costs are required due to the Request.

7. System Operating Limits Methodology

The annual Assessment of Bulk Electric System performance will include evaluation of boundary conditions in the near-term planning horizon and the establishment of System Operating Limits (SOL's), as necessary, to maintain transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading outages or uncontrolled separation shall not occur. The annual Assessment will include pre-contingency, single contingency and multiple contingencies, indicated as NERC Categories A, B and C in Table 1. The SOL shall not exceed the associated Facility Ratings. SOL's that result in uncontrolled tripping of Extra High Voltage (EHV) facilities in other areas or generators in other areas will be considered Interconnected Reliability Operating Limits (IROL's). The Tv for an IROL in the planning horizon is 30 minutes.

The SOL evaluation will use the Base Case models developed annually to support the planning process. Section 4 – Base Case Model Development describes the anticipated transmission system configuration, generation dispatch, load level, outages and other internal and external modeling details incorporated into the models.

The SOL evaluation will use the contingency selection criteria used in the planning process. Section 5.6 – Credible Contingency Selection describes the contingencies.

The steady-state analysis of system performance simulates single and multiple contingencies without implementation of manual or automatic system adjustments. Voltage Stability analysis will be performed if a BES contingency simulated in the steady-state analysis causes a BES voltage deviation greater than 8 percent or a post-contingency, pre-capacitor switching BES voltage less than 85 percent. Angular Stability analysis will be performed to assess the impact of the subsequent tripping of facilities with a post-contingency flow in excess of 110 percent of the emergency thermal limit.

Steady-state voltage stability analysis will be performed via V-Q analysis on summer and winter peak models. Transient voltage stability analysis will be performed on summer and winter peak models. Transient and dynamic angular stability will be performed on

1) summer peak models with all generators at maximum output and the necessary export split equally to the north and south, and
2) light load models with all coal fired generators at maximum output and an incremental 500 MW export split equally to the north and south.

The applicable reliability margins for stability are described in section 5.4 – Voltage Stability Limits and section 5.5 – Transient Stability Limits. E.ON does not use Special Protection Systems.

The determination of SOL's, starting with all Facilities in service, may include the following actions in response to a single contingency:

- Planned or controlled interruption of radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area
- System reconfiguration through manual or automatic control or protection actions
- To prepare for the next contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology

In addition to the preceding actions in response to a single contingency, the determination of SOL's, starting will all Facilities in service, may include the following action in response to multiple contingencies:

- Planned or 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) electric power transfers

Table 1
Transmission Contingencies and Measurements

NERC Cat	Contingency	Steady State Analysis	Dynamic Analysis	Required Performance Level
A	No Contingencies	Yes		1
B 1-3	Outage of a generator, transmission circuit, transformer or shunt device.	Yes	a,b	2
C3	Outage of two generators.	Yes	b	2
C3	Outage of a generator and a transmission circuit.	Yes	b	2
C3	Outage of a generator and a transformer.	Yes	b	2
	Outage of a transmission circuit or transformer with plant at maximum output.	Yes		2
C1	Outage of a bus section.	Yes	c	3
C2	Outage of a breaker.	Yes	c	3
C5	Outage of two circuits on a multiple circuit tower line. [more than 1 mile in length]	Yes	d	3
C3	Outage of two transmission circuits.	Yes	b	4
C3	Outage of a transmission circuit and a transformer.	Yes	b	4
C3	Outage of two transformers.	Yes	b	4
C6-8 D1-3	Outage of a generator, transmission circuit or transformer.	No	e,f	2
C9,D4	Outage of a bus section.	No	e,f	3
D5	Outage of a breaker.	No	g	3
D6	Outage of tower line with three or more circuits	Yes	a	5
D7	All transmission on a common right-of way [more than 1 mile in length]	Yes	a	5
D8	Outage of a substation (one voltage level plus transformers	Yes	a	5
D9	Outage of a switching station (one voltage level plus transformers	Yes	a	5
D10	Outage of all generating units at a station	Yes	a	5
D11	Loss of a large load or major Load center	Yes	a	5

Fault Types:

a) None
b) Single Line Ground or 3-Phase, with Normal Clearing
c) Single Line Ground, with Normal Clearing
d) Non 3-Phase, with Normal Clearing
e) Single Line Ground, with Delayed Clearing
f) 3-Phase with Delayed Clearing
g) 3-Phase with Normal Clearing

Table 2
Regulated Plant Voltage

Power Plant	Transmission Bus (kV)	Voltage (kV)	Per Unit Voltage
Brown	Brown N 138	141	1.022
Bluegrass	Buckner 345	352	1.020
Cane Run	Cane Run Sw 138	139	1.007
Ghent	Ghent 345	352	1.020
Green River	Green River 138	141	1.022
Mill Creek	Mill Creek 345	352	1.020
Paddys Run	Paddys Run 138	139	1.007
Trimble County	Trimble Co 345	352	1.020
Tyrone	Tyrone 69	70	1.014
Elmer Smith	Smith 138	141	1.022

Table 3
Minimum Transmission Voltage at Generator Connections

Transmission Bus	Connected Generator	Minimum kV Voltage	Minimum p.u. Voltage	Limit
Brown Plant 138	Brown 1		0.935	Gen
	Brown 2	133.0	0.964	Aux
Brown North 138	Brown 3	128.5	0.931	Aux
Brown CT 138	Brown 5		0.928	Gen
	Brown 6	128.2	0.929	Gen
	Brown 7		0.929	Gen
	Brown 8		0.918	Gen
	Brown 9		0.918	Gen
	Brown 10		0.918	Gen
	Brown 11		0.918	Gen
Cane Run Sw 138	Cane Run 4		0.936	Gen
	Cane Run 5	129.9	0.941	Gen
Cane Run 6	Cane Run 6	129.7	0.940	Gen
Ghent 138	Ghent 1	130.7	0.947	Aux
Ghent 345	Ghent 2		0.959	Gen
	Ghent 3	332.6	0.964	Gen
	Ghent 4		0.963	Gen
Green River 138	Green River 3		0.926	Aux
	Green River 4	130.3	0.944	Aux
Mill Creek 345	Mill Creek 1		0.958	Gen
	Mill Creek 2	330.5	0.958	Gen
	Mill Creek 3		0.953	Gen
	Mill Creek 4		0.953	Gen
Paddys Run 138	Paddys Run 13	129.3	0.937	Gen
Trimble Co 345	Trimble Co 1	331.2	0.960	Gen
Trimble Co CT 345	Trimble Co 5	325.3	0.943	Gen
	Trimble Co 6		0.943	Gen
	Trimble Co 7		0.943	Gen
	Trimble Co 8		0.943	Gen
	Trimble Co 9		0.943	Gen
	Trimble Co 10		0.943	Gen
Smith 138	Smith 1		0.942	Gen
	Smith 2	130.4	0.945	Gen

KENTUCKY UTILITIES COMPANY

CASE NO. 2010-00164

Response to Commission Staff's First Data Request
Dated January 7, 2011

Question No. 3

Witness: Edwin R. Staton

Q-3. Provide the following information for the Power Flow scenarios studied:

a. What season and year system models were used in the power flow studies?
b. What area transfers were in place in these models?
c. Discuss the sensitivity of the results of the studies to these transfers.

A-3.

a. 2010 summer, 2010 winter, and 2016 summer
b. Long-term firm transfers (NERC base case) were used. Additional area-area short-term and economic transfers were not simulated.
c. Not applicable.

KENTUCKY UTILITIES COMPANY

CASE NO. 2010-00164

Response to Commission Staff's First Data Request
Dated January 7, 2011

Question No. 4

Witness: Edwin R. Staton

Q-4. Provide the generation dispatch scenarios used at the Tennessee Valley Authority's ("TVA") Shawnee Steam and other electrically close generation plants in each case studied and discuss the sensitivity of the results of these studies to these transfers.

A-4. All coal-fired generation at Joppa (1010 MW) and Shawnee (1600 MW) was on-line. Sensitivity cases were not simulated.

KENTUCKY UTILITIES COMPANY

CASE NO. 2010-00164

Response to Commission Staff's First Data Request
Dated January 7, 2011

Question No. 5

Witness: Edwin R. Staton

Q-5. TVA recently announced plans to retire older fossil generating units including Unit 10 at Shawnee Steam Plant. Was this and future additional retirements considered in these analyses? If so, which units were considered and for what timeframe?

A-5. No, these studies were performed prior the TVA announcement. KU was not aware of any planned retirements in the area at the time the study was performed.

KENTUCKY UTILITIES COMPANY

CASE NO. 2010-00164

Response to Commission Staff's First Data Request
Dated January 7, 2011

Question No. 6

Witness: Edwin R. Staton

Q-6. Provide a summary of the short-circuit analysis performed for the proposed new transmission line.

A-6. The proposed construction includes the addition of 5% reactors in both of the Grahamville – DOE 161 kV lines. This will increase the impedance and lower short circuit values. Therefore, no analysis was performed.

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Question No. 7

Witness: Edwin R. Staton

Q-7. Currently, it is stated that only 125 MW of firm load can be provided to Paducah, KY and Princeton, KY without the proposed system improvements. After the proposed line is in service how much total load can be supplied to these two entities?

A-7. The proposed plan is adequate to serve the forecasted load through 2022 which is forecasted to be 232.7 MW by the summer of 2022. Studies were not performed to quantify the maximum load that could be served.

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Question No. 8

Witness: Edwin R. Staton

Q-8. What are the projected load growths rates (normal and extreme) for both Paducah and Princeton?

A-8. Kentucky Municipal Power Agency ("KMPA") provided forecasts from 2010 through 2022. The first year and last year MW loads are:

Year	Summer	Winter
2010	203.6	132.3
2022	232.7	150.5

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Question No. 9

Witness: Edwin R. Staton

Q-9. Were the prior TVA developed Paducah and Princeton load growth studies used for load forecasting or were new ones developed by Kentucky Utilities Company ("KU") or others?

A-9. Neither, the forecast was provided by KMPA.

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Question No. 10

Witness: Edwin R. Staton

Q-10. Provide a brief description of the load forecasting process(s) used for Paducah and for Princeton.

A-10. KU did not develop the load forecasts for Paducah and Princeton. KMPA provided those forecasts which KU then considered along with all other Network Integration Transmission Service ("NITS") customers.

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Question No. 11

Witness: Edwin R. Staton

Q-11. How will the proposed transmission line be terminated at the DOE end?

A-11. A structure will be installed in the EEI W1 161kV Line in the second span outside the DOE substation. The proposed transmission line will interconnect with the EEI W1 line at this location.

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Question No. 12

Witness: Edwin R. Staton

Q-12. How close will the nearest residential structure be to the new transmission line?

A-12. The proposed line will require the removal of one residential structure and the relocation of one mobile home. Agreements have been reached with both property owners to accommodate the proposed line with the residential structure having already been vacated. The relocated mobile home will likely be the nearest residential structure, and it will not be closer than 75 feet from the new transmission centerline.

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Question No. 13

Witness: Edwin R. Staton

Q-13. What alternative line designs such as single pole, vertical phase, etc. was considered to increase the distance to structures?

A-13. As discussed in Response to Question No. 12, the removal of one residential structure and the relocation of one mobile home will be required. As a result, distances to residential structures will be a minimum of 75 feet from centerline; therefore, consideration of alternative (more costly) designs to increase the distance to the structures was not considered necessary.

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Question No. 14

Witness: Edwin R. Staton

Q-14. Provide the load levels studied at the DOE Gaseous Diffusion Plant for this project.

A-14. The following is included in the Facility Study referenced in Question No. 15:

<u>10S-DOE30</u>: The load modeled for the United States Department of Energy (DOE) facility west of Paducah is 150 MW in the 2010 summer model and 30 MW in the [*sic*] 2016. It is expected that the DOE load will reduce to 30 MW but the timeframe is uncertain. A 2010 summer model was developed to simulate a load reduction as early as 2010.

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Question No. 15

Witness: Edwin R. Staton

Q-15. Provide a copy of the "2008 – 004 Facility Study" associated with this project.

A-15. The Facilities Study is confidential and will be the subject of a Petition for Confidential Protection that will be filed at the Public Service Commission. It has already been provided to P&D pursuant to a Confidentiality Agreement.

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Question No. 16

Witness: Edwin R. Staton

Q-16. Refer to the direct testimony of Edwin Staton. At pages 2-3, he states that the proposed transmission line is needed to provide Network Integration Transmission Service to the Kentucky Municipal Power Agency.

a. Is the Kentucky Municipal Power Agency either a full-power requirements or a partial-power requirements customer of KU? If yes, explain in detail the annual quantities of power (demand and energy) sold by KU to the Kentucky Municipal Power Agency from 2008 through 2010, and provide a copy of each power sale contract.

b. Was the electric load (i.e. either demand, energy, or both) of the Kentucky Municipal Power Agency included in the load forecast set forth in KU's Integrated Resource Plan ("IRP") as filed with the Commission in 2008? If yes, indicate where in that IRP the load of the Kentucky Municipal Power Agency is shown.

A-16.

a. No, KMPA was not a full-power requirements or a partial-power requirements customer of KU.

b. No, it was not.

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Question No. 17

Witness: Lonnie E. Bellar / Counsel

Q-17. KRS 278.020(1) prohibits KU from beginning the construction of any facility for furnishing to the public any of the services listed in KRS 278.010 until the Commission has certified that public convenience and necessity require the construction. Explain how KU's provision of transmission service to the Kentucky Municipal Power Agency constitutes utility service to or for the public as defined in KRS 278.010(3)(a).

A-17. By virtue of KU's FERC-mandated open access obligation to provide service to KMPA, the construction of the proposed facilities responds to the needs of the public residing in Paducah and Princeton. See Edwin R. Staton Direct Testimony at 8. After construction, the proposed line will be a "network facility," meaning it will be used to support OATT customers, both Network and Point-to Point, from time to time, including LG&E/KU customers. The service to Princeton and Paducah will be similar to the network integration transmission service provided by LG&E/KU to East Kentucky Power Cooperative and other network customers. See Lonnie E Bellar Direct Testimony at 4. Adding the new network facilities will also enhance reliability to all customers of KU. See Lonnie E Bellar Direct Testimony at 5. Because KRS 278.010(3)(a) specifies that a utility includes any person who owns, controls, operates, or manages any facility used or to be used for or in connection with the transmission of electricity to or for the public for compensation and KRS 278.010(13) defines service as including any practice or requirement in any way relating to the service of a utility, it is clear that the proposed transmission line will provide utility service to or for the public.

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Question No. 18

Witness: Lonnie E. Bellar / Counsel

Q-18. KRS 278.030(2) provides, in pertinent part, that "[e]very utility shall furnish adequate, efficient and reasonable service…." Is the transmission line proposed in this case needed by KU to meet its statutory obligation under KRS 278.030(2) to provide adequate, efficient and reasonable service to the Kentucky Municipal Power Agency? If yes, explain in detail.

A-18. KU is required to comply with certain FERC rules and orders described in Lonnie E Bellar's Direct Testimony at 5-6 with respect to the provision of service to Kentucky Municipal Power Agency. The support to LG&E and KU customers and the additional reliability to KU customers described in the response to Question No. 17 above relate to KU's statutory obligation under KRS 278.030(2) to provide adequate, efficient and reasonable service.

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Question No. 19

Witness: Lonnie E. Bellar / Counsel

Q-19. KRS 278.040(2) provides, in pertinent part, that "[t]he Commission shall have exclusive jurisdiction over the regulation of rates and service of utilities…."

a. Is the transmission service provided by KU to the Kentucky Municipal Power Agency an activity regulated by this Commission, and is that transmission service subject to this Commission's jurisdiction? If yes, explain in detail.

b. Does KU provide any service to the Kentucky Municipal Power Agency that is regulated by this Commission? If yes, explain in detail.

A-19. a. Yes. KRS 278.020(2) and (8) gives the Commission authority to regulate the construction of the proposed line. In addition, the Commission's safety regulations will be applicable to the line.

b. See the Response to Question No. 19(a) above.

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Question No. 20

Witness: Lonnie E. Bellar / Counsel

Q-20. Explain why the transmission line proposed in this case to serve the Kentucky Municipal Power Agency is not a "nonregulated electric transmission line" as that term is defined in KRS 278.700(5).

A-20. KRS 278.700(5) defines a "nonregulated electric transmission line" as one "for which no certificate of public convenience and necessity is required." As noted in the response to Question No. 17, the proposed transmission line will provide utility service to the public. Further, KRS 278.020(2) clarifies that "construction of any electric transmission line of 138 kilovolts or more and of more than 5,280 feet in length" requires a certificate of public convenience and necessity. As a result, the proposed transmission line is a not "nonregulated electric transmission line" as defined in KRS 278.700(5).

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Question No. 21

Witness: Edwin R. Staton

Q-21. Revise the map of the preferred route and include parcel indentifiers on those parcels crossed by the proposed transmission line. Revise the list of property owners in Exhibit 7 to include parcel identifiers with the corresponding property owner.

A-21. Please see the revised map that includes parcel identifiers and an updated Exhibit 7.

Update to Exhibit 7

Property Owner	Parcel Identifier
Hugh T. and Nancy Davis 5418 Metropolis Lake Road West Paducah, KY 42086 (2) Contiguous Parcels	P-1, P-2
Dennis and Charlotte Wheatley 5422 Metropolis Lake Road West Paducah, KY 42086	P-3
Kentucky Utilities Company 5445 Metropolis Lake Road West Paducah, KY 42086	P-4
Brian and Heather Tabor 5439 Metropolis Lake Road West Paducah, KY 42086	P-5
Steven and Angela Woods 5421 Metropolis Lake Road West Paducah, KY 42086	P-6
Mr. Elbert Davis 9460 McCaw Rd West Paducah, KY 42086 Mailing Address 282 Shavers Drive Bremen, KY 42325	P-7, P-8
Larry and Janine Davis 9750 McCaw Road West Paducah, KY 42086	P-9
Department of Energy Mailing Address: 250 East Fifth Street, Suite 500 Cincinnati, OH 45202	P-10, P-11

SURVEY BY

SCALES
1" = 600'

REVISED BY	DATE

SURVEY BY:
DRAWN BY:
CHECKED BY:

GRAHAMVILLE - EEI AREA MAP

DATE: 1/10/2011

UNIT NO.: 89

Kentucky Utilities Company
LEXINGTON, KENTUCKY

SHEET
AREA MAP