Final Report
Focused Review of Documentation
Filed by LG&E/KU
For a Proposed 138 kV Transmission Line
Within Kentucky
Case No. 2005-00154

Presented to:

The Kentucky Public Service Commission

By:

THE LIBERTY CONSULTING GROUP

65 Main Street
Quentin, Pennsylvania 17083

(717) 270-4500 (voice)
(717) 270-0555 (facsimile)
Admin@LibertyConsultingGroup.com (e-mail)

June 14, 2005

Table of Contents

I. Introduction and Conclusion Summary

A. Purpose and Scope of this Report

1. Background

Pursuant to KRS 278.255, the Kentucky Public Service Commission (*Commission* or *KPSC*), retained The Liberty Consulting Group (*Liberty*) to perform a focused Need Review of documentation associated with a 138 kilovolt (kV) transmission line proposed for construction by Louisville Gas and Electric Company and Kentucky Utilities (*LG&E/KU* or *Companies*).

Liberty is a management and technical consulting firm that specializes in the public-utility industry. Liberty has extensive experience in conducting focused reviews of this type. Liberty has served commissions in 33 different states and the District of Columbia in conducting focused reviews and management audits similar to this work related to the LG&E/KU transmission project.

This report provides the results of Liberty's review of the application of LG&E/KU for a Certificate of Public Convenience and Necessity (*Certificate*) to construct a 138 kV transmission line between the West Frankfort and Tyrone substations.

2. Project Scope and Objectives

The overall objective of this project was to review LG&E/KU's analyses regarding the need for, and engineering aspects of, the proposed high voltage transmission line. The proposed 138 kV transmission line would be approximately 12.4 miles in length, running from KU's Tyrone Substation to KU's West Frankfort Substation. Included in this report is an independent evaluation of LG&E/KU's analyses and conclusions in support of the reasonableness of the need for the proposed transmission line.

This project was a focused review. Liberty reviewed LG&E/KU's work but did not produce an independent transmission study. However, this report does encompass all the issues relevant to the need for the additional transmission line. An evaluation of the overall cost or the engineering design aspects of the proposed line was not part of the scope of work for this project.

Liberty's work focused on the following aspects of the Need Review:

1. The utility's analysis of the ability of existing facilities to reliably serve existing and expected load, including the utility's power flow analyses and stability analyses.
2. The utility's analyses that support the need for the proposed transmission line. The evaluation included whether adequate consideration was given to:
   a. The upgrade of existing lines or facilities and transmission routes
   b. Other alternatives, including the use of generation and power factor improvement
   c. Whether wheeling power through neighboring systems or through interconnections with neighboring systems would be a viable alternative to construction of the proposed new transmission line.

B. Project Overview

1. Project Description

LG&E and KU are the two utility businesses of LG&E Energy LLC that are regulated in Kentucky by the Kentucky Public Service Commission. LG&E Energy LLC is headquartered in Louisville and is a diversified energy services company that is a member of the E.ON AG family of companies, headquartered in Dusseldorf, Germany. LG&E is an electricity and natural gas utility based in Louisville and serves customers in Louisville and sixteen surrounding counties. KU is an electricity utility based in Lexington and serves 77 Kentucky counties and five counties in Virginia. Together these two utilities have a joint generation capacity of 9,000 MW and serve 908,000 electricity customers and 318,000 natural gas customers over a transmission and distribution network covering some 27,000 square miles.[1]

On May 11, 2005, LG&E/KU filed an application with the Commission to construct a 138 kV line that is more than one mile in length. By Kentucky law, such a facility requires a Certificate prior to construction. The Commission assigned the application Case No. 2005-00154.[2]

The proposed 138 kV transmission line would be approximately 12.4 miles in length, running from KU's Tyrone Substation in Woodford County through Anderson and Franklin County to KU's West Frankfort Substation. KU will own 100% of the proposed transmission line.[3]

The proposed transmission facilities will be used to transmit electric power required by the projected load that will be served from the proposed 750 MW nominal net (732 MW summer rating) supercritical, pulverized, coal-fired, base-load generating unit to be located at the Trimble County Generating Station ("TC2") as well as base load that will be served from other sources.[4] The projected cost of the proposed transmission line and ancillary facilities is $7.9 million.[5]

2. Summary of Liberty's Work

Liberty performed its independent Need Review by organizing its work in two main Task Areas. This report addresses these Task Areas as follows:

Task Area One – Chapter Two, Technical Need Review

To determine if the proposed facilities were required from a technical viewpoint, Liberty reviewed LG&E/KU's analyses, including its power flow analysis and long range plans, of the proposed 138 kV facilities to determine whether they would reliably serve the existing and expected load in the service territory.

[1] LG&E Energy Web Site.
[2] May 11, 2005 application of LG&E/KU.
[3] May 11, 2005 application of LG&E/KU, paragraph 3.
[4] May 11, 2005 application of LG&E/KU, paragraph 5.
[5] May 11, 2005 application of LG&E/KU, direct testimony of J. Nate Mullins, page 3.

Task Area Two – Chapter Three, Alternatives

To determine if LG&E/KU's analyses properly considered appropriate engineering alternatives to meet its needs, Liberty's evaluation considered whether LG&E/KU gave adequate consideration to:

a. The upgrade of existing lines or facilities and transmission routes
b. Other alternatives, including the use of generation and power factor improvement
c. Whether wheeling power through neighboring systems or through interconnections with neighboring systems would be a viable alternative to construction of the proposed new transmission line.

Review Process

Liberty reviewed LG&E/KU's filed application for Case No. 2005-00154. In addition, Liberty reviewed data and documents provided by LG&E/KU in response to written information requests from Liberty. Liberty conducted extensive on-site interviews in Louisville, Kentucky on May 12-13, 2005, with LG&E/KU management and subject-matter experts as listed below:

John Wolfram	Manager, Regulatory Affairs
Michael Toll	Manager, Planning and Substations
Brent Ingebrightson	Regulatory Analyst
David Sinclair	Director, Market Analysis and Valuation
Greg Cornett	Counsel, Outside Regulatory

In addition, Liberty conducted extensive interviews with the following Midwest Independent System Operator (*MISO*) personnel[6] at their offices in Carmel, Indiana on May 17-18, 2005:

Raja Srivastava	Principal Engineer
Ron Arness	Manager, Transmission Services
Ron Slagel	Engineer

C. Conclusion Summary

On the basis of materials reviewed, and interviews conducted, Liberty makes the following conclusions related to the need for the 138 kV transmission line from the West Frankfort substation to the Tyrone substation as proposed by LG&E/KU:

1. LG&E/KU needs the construction of its proposed West Frankfort to Tyrone 138 kV transmission line on the proposed schedule in order to meet the electric service requirements of integrating the new TC2 unit into the transmission system.

2. LG&E/KU performed the appropriate system studies and analyses to justify the need for the proposed 138 kV transmission line. LG&E/KU appropriately considered least-cost alternatives, including reasonable on-system upgrades, interconnections with and wheeling through neighboring electric systems, installation of on-system generation, and the use of power factor correction.

[6] Mr. Wolfram and Mr. Toll from LG&E/KU were also present.

II. Technical Need Review

A. Background

The Companies applied to the Commission for a certificate of public convenience and necessity to construct a 138 kV transmission line. The proposed 138 kV transmission line would be approximately 12.4 miles in length, running from KU's Tyrone Substation in Woodford County through Anderson and Franklin County to KU's West Frankfort Substation. KU will own 100% of the proposed transmission line.

The proposed transmission facilities would be used to transmit electric power required by the projected load that will be served from a proposed 750 MW nominal net (732 MW summer rating), supercritical, pulverized coal-fired, base-load generating unit to be located at the Trimble County Generating Station *(TC2)*, as well as load that will be served from other sources.

The proposed transmission facilities would be used to transmit 75 percent of the electric power from TC2 to the Companies' electric customers and accommodate the operation of TC2. LG&E will own 19 percent of the Companies' share of the new generating unit and KU will own 81 percent. The remaining 25 percent of the unit will be owned by the Illinois Municipal Electric Agency and the Indiana Municipal Power Agency.[1] The power from TC2 will serve the Companies' approximate 900,000 electric customers in Kentucky throughout 83 counties and 7,300 square miles of service territory.[2]

B. Reliability Criteria

1. Definition

Liberty reviewed the steady state criteria[3] and the transient stability criteria[4] used by LG&E/KU to determine if they were reasonable and within the bounds of good utility practice. The review consisted of an evaluation of thermal contingency performance requirements,[5] dynamic contingency performance requirements,[6] allowable voltage limits,[7] and the contingencies chosen for their reasonable likelihood of occurrence. The review also considered whether LG&E/KU

[1] Application for TC2, Case No. 2004-00507, Vol. I, page 4.
[2] Integrated Resource Plan, Case No. 2005-00162, Vol. I, page 5-1.
[3] Steady state criteria are the outage conditions that a power system is designed to meet for reliability purposes. The criteria state the type of contingencies that must be withstood without overloading equipment while providing adequate voltages to customers.
[4] Transient stability criteria are the outage conditions that a power system is designed to meet for reliability purposes. The criteria state the type of contingencies that must be withstood without interfering with the dynamic operation of the power system.
[5] Part of the steady state criteria that states the types of outages that the system is designed to withstand while maintaining power flow on equipment within its thermal capabilities.
[6] Part of the dynamic criteria that states the type of outages that the system is designed to withstand while maintaining a stable relationship with the dynamic elements of the power system.
[7] In addition to designing a power system to prevent overloads for reasonably expected contingencies, the system must be designed to provide adequate voltage to customers for proper operation of their electric equipment. Allowable voltage limits on the transmission system are such that if maintained, customer equipment on the lower voltage distribution system will operate properly.

used appropriate generation bias in its analyses. Generation bias weights the level of generation used in the study compared to how system generation is normally dispatched in a manner to produce conservative analysis results.

2. Discussion

LG&E/KU's most recent revision of its reliability guidelines is dated March 11, 2005.[8] These guidelines state that the reliability standards established by the East Central Area Reliability Coordination Agreement (*ECAR*) are met or exceeded. More specifically, the guidelines allow for no voltage excursion outside of prescribed limits, and no loss of load for some double contingencies. This exceeds the ECAR reliability standards, as well as those established by the National Electric Reliability Council (*NERC*), which allow for a degree of controlled customer interruptions for multiple element outages.[9] In addition, cascading outages are not permitted by the LG&E/KU reliability guidelines for any condition because both the normal and emergency ratings for transmission components established by LG&E/KU are continuous ratings.

LG&E/KU has an established voltage criterion for all levels of its transmission system (see Table II.1). This criterion specifies allowable voltage ranges for operation of the transmission system for both normal and emergency conditions, and establishes specific voltages to be maintained at generating stations.

Table II.1
LG&E/KU Transmission Voltage Criteria[10]

Transmission Conditions	**500 kV Bus Voltage - %**		**All Other Bus Voltages - %**	
	Minimum*	Maximum**	Minimum*	Maximum
Normal	94.0	110.0	94.0	105.0
All Contingencies	90.0	110.0	90.0	105.0

* Generator bus voltages have individually determined limits to assure that auxiliary bus voltages do not go below 95.0 percent.
** The 500 kV transmission system is designed to operate at 110.0 percent of nominal voltage.

The LG&E/KU transmission system planning guidelines also establish contingencies for which the above voltage limits apply. LG&E/KU requires that voltage and thermal conditions remain within normal limits for "all elements in" normal service conditions, and that they remain within applicable emergency limits under all contingency conditions. In addition, for a specified set of predetermined contingencies, no loss of load or system instability is permitted.

The guidelines used by LG&E/KU are deterministic in nature as they assume the probability of an outage is 1.00. The normal and emergency thermal equipment ratings used by LG&E/KU are continuous ratings. The conditions for which LG&E/KU designs its system for no loss of load situations are listed in Table II.2 below. Because some double contingencies are used in system design without loss of load, LG&E/KU's transmission planning guidelines exceed NERC N-1

[8] Although LG&E/KU calls its reliability documents guidelines, and recognizing that adherence to ECAR reliability planning standards is voluntary, LG&E/KU states that it adheres to ECAR requirements.
[9] Response to Liberty Data Request #16.
[10] Response to Liberty Data Request #16.

standards.[11] LG&E/KU defines a single contingency element as a generator, transmission circuit, or a transformer.

Table II.2
LG&E/KU Transmission Contingencies and Measurements[12]

	System Impacts or Limits		
Contingencies	**Thermal Limits**	**Voltage Limits**	**Loss of Demand or Curtailed Firm Transfers**
None	Normal	Normal	No
Generator, Transmission Circuit, or Transformer	Emergency	Emergency	No
Outage of Two Generators	Emergency	Emergency	No
Generator and Transmission Circuit	Emergency	Emergency	No
Generator and a Transformer	Emergency	Emergency	No
Transmission Circuit or Transformer with Plant at Maximum Output	Emergency	Emergency	No

3. Analysis

The Companies' power system has two major load centers, Lexington on the eastern side of the system and Louisville on the western side of the system. Both local and remote generation serve these load centers. Locally, the Brown generating plant (summer capabilities are 697 MW of base load and 947 MW of peaking combustion turbines) serves the Lexington load and the Mill Creek (summer capabilities are 1472 MW of base load and 0 MW of peaking combustion turbines) and Cane Run (summer capabilities are 563 MW of base load and 0 MW of peaking combustion turbines) generating plants serve the Louisville load. Remotely, the Ghent generating plant (summer capabilities are 1945 MW of base load and 0 MW of peaking combustion turbines) serves the Lexington load center and the Trimble County generating plant (summer capabilities are 383 MW of base load and 960 MW of peaking combustion turbines) serves the Louisville load center.[13] Radial 345 kV transmission facilities connect the remote generating plants to their respective load centers. In its analysis, the Companies modeled Trimble County at full generation, including all combustion turbines, and modeled reduced generation at the Brown generating plant by merit order.[14,15] The modeling of generation in this manner stresses the system and creates generation bias when simulating transmission circuit or generation contingency conditions. Further generation bias is created when generation contingencies are simulated.

[11] These NERC standards are voluntary and often referred to as N-1 standards. They require that system voltages and ratings remain within applicable limits under specified conditions; N-1 refers to the system state as normal minus one element.
[12] Response to Liberty Data Request #16.
[13] Application for TC2, Case No. 2004-00507, Vol. I, Attachment JPM-2.
[14] Merit order is removing units from service starting with the most expensive to operate or placing units in service starting with the unit least expensive to operate.
[15] Interview of May 17, 2005.

NERC established voluntary reliability standards for utilities to follow. These NERC standards are often referred to as N-1 standards, and require that system voltages and ratings remain within applicable limits under specified conditions and that system dynamics be maintained for specified conditions. ECAR, one of the NERC Reliability Council Regions, is responsible for implementing the NERC reliability standards. As a member of ECAR, LG&E/KU reliability standards must conform to or exceed those established by ECAR. Liberty found that the thermal and transient stability contingency performance requirements were consistent with, or stricter than, those required by ECAR, and that by the use of transmission emergency circuit ratings that can be continuously applied, the potential for cascading outages is virtually eliminated. Liberty also found that the LG&E/KU voltage limits are reasonable, inclusive of system requirements, and consistent with ECAR requirements.

Liberty concluded that LG&E/KU used appropriate generation bias in its analysis to produce conservative results.

C. Thermal Ratings

1. Definition

Liberty reviewed the thermal ratings of the limiting transmission line components, including equipment in the substation, to ensure that LG&E/KU applied appropriate ratings and chose equipment that is reasonably compatible with the system. Liberty reviewed both normal and emergency ratings.

2. Discussion

The Companies document their transmission equipment thermal ratings in "Transmission Rating Methodologies," dated December 1, 2004. This document describes the factors used for planning purposes in the development of normal and emergency ratings at pre-determined summer and winter ambient conditions.[16] However, to fully use the thermal capacity of the transmission system at temperatures less than those used for planning purposes, the Companies operate the system using ratings adjusted for actual or expected ambient conditions.[17]

The Companies' planning group supplies these thermal ratings to the Midwest Independent System Operator (*MISO*) for use in modeling its system studies, and to the National Electric Reliability Council (*NERC*) for use in the Multi-regional Model Working Group (*MMWG*) model.[18] In general, for the lines and substation buses, the Companies derive summer ratings for system normal conditions and emergency conditions. The emergency ratings for lines and buses are those that can be applied on a long-term continuous basis without cascading outages occurring caused by overloading. However, the Companies must inspect and evaluate lines for appropriate clearances before being operated at the emergency ratings.[19]

16 Response to Liberty Data Request #12.
17 Interview of May 13, 2005.
18 Interview of May 13, 2005.
19 Interview of May 12, 2005.

Ratings of lines and buses connected to other utilities at flowgates may be limited by applicable Transmission Reliability Margins (*TRM*)[20] or Capacity Benefit Margin (*CBM*).[21] However, no utility in the ECAR region requires CBM. In the ECAR region, only the Indianapolis Power and Light Company requires a 2 percent TRM reduction.[22]

LG&E/KU constructs detailed ratings tables from -20^{o} F to 120^{o} F for all transmission system components for use by the system operators in determining the limiting elements by temperature.[23]

For system load flow studies, LG&E/KU bases the adequacy of all components of a line or bus at forecast peak demand on ratings determined using the Companies' rating method. The facility loading is limited to the rating of the limiting component, or the limiting component may be upgraded to increase its rating. The Companies limit loading of a line or bus based on its limiting component rating at the actual or expected operating temperatures.[24]

Line Conductors[25]

LG&E/KU's planners apply thermal ratings to overhead transmission lines according to formulas from the ECAR Transmission Conductor Thermal Ratings report. Factors involved in these formulas include conductor size, AC resistance and the oxidation factor, the orientation of the conductor to the sun, the elevation of the conductor above sea level, maximum operating temperature, wind velocity, and ambient air temperature. The Companies' planning group uses a wind velocity of 2 mph, a summer ambient temperature of 96º F, and a winter ambient temperature of 23° F. LG&E/KU chose the temperatures such that the winter peak would always occur at a lower temperature and the summer peak had a 50 percent chance of occurring at a higher temperature.[26,27]

LG&E/KU operates its overhead transmission lines up to 212° F. However, according to its rating methods, it will not operate the lines above the normal rating of 176° F without first performing clearance inspections and calculations to assure conformance to the National Electrical Safety Code (*NESC*). It performs these inspections and calculations to ensure that appropriate clearances to ground, buildings, roads, water, railroads, and other lines will be maintained when it operates lines at 212° F.[28] Many of LG&E/KU's older lines were constructed to operate at 120^{o} F; however, the Companies do not perform inspections or calculations for line operation below 176^{o} F.[29]

---

[20] Transmission Reliability Margin is the reduction of a transmission limit to allow a margin for unknowns or errant flow.
[21] Capacity Benefit Margin holds in reserve adequate transmission capability to allow for the loss of the largest unit in the control area.
[22] Interview of May 17, 2005.
[23] Interview of May 12, 2005.
[24] Interview of May 13, 2005.
[25] Response to Liberty Data Request #12.
[26] Interview of May 13, 2005.
[27] For system planning, many large utilities use a summer load forecast that would be exceeded less frequently. A 10 percent chance of exceeding the forecast is becoming more commonplace in the industry.
[28] Vegetation is not specifically mentioned. Clearance to vegetation under emergency conditions should be formally included.
[29] Interview of May 13, 2005.

The Companies use manufacturers' summer and winter seasonal continuous current ratings for rating underground line conductors.

Substation Buses

LG&E/KU rates buses made from conductors in the same manner as it does overhead lines and designs these buses to be operated up to a maximum temperature of 212° F. It designs tubular and angle buses in accordance with the IEEE "Guide for Substation Rigid Bus Structures" to be operated up to 212° F.[30]

High Voltage Switches

LG&E/KU follows the IEEE "Loading Guide for AC High Voltage Air Switches" for rating air switches. For planning purposes, it uses 96° F as its standard summer ambient temperature and 23° F as its standard winter temperature. It allows switches to be loaded up to 105 percent of manufacturers' ratings for summer normal conditions, up to 120 percent for summer emergency conditions, up to 132 percent for winter normal conditions, and up to 135 percent for winter emergency conditions. It can operate switches at emergency load ratings for more than 24 hours.[31]

Large Transmission Transformers

For large transmission system transformers, LG&E/KU follows IEEE Standard 756, "Guide for Loading Mineral Oil Immersed Transformers Rated In Excess of 100 MVA (65° C Rise)," which allows these transformers to be operated above manufacturers' nameplate ratings. LG&E/KU determined an acceptable loss of transformer life based on economic models. Acceptable loss of life, caused by loading in excess of manufacturer's continuous ratings over time, dictates maximum transformer ratings, which the Companies derived to be consistent with its design and risk criteria. Since transformer insulation degradation and loss of life are caused by excessive temperature over time, the hottest spot temperature (caused by load and ambient temperature conditions) and time period are the load-limiting factors.[32]

With no system outages, the Companies can operate these transformers in the 120° C to 130° C range for up to 4 hours daily on a regular and frequent basis.[33] With long-term outages of a transmission system element, the Companies can operate the transformers in the 120° C to 130° C range for up to 4 hours daily, and in the 130° C to 140° C range for up to 6 hours daily, over several months, on an infrequent basis of 2 or 3 occurrences over the normal transformer lifetime. For rating transformers, planners use 104° F for the summer daily peak ambient temperature and 23° F for the winter peak daily temperature. At these ambient temperatures, they plan for these transformers to be loaded up to 100 percent of the manufacturers' ratings for summer normal conditions, up to 115 percent for summer emergency conditions, up to 130

[30] Response to Liberty Data Request #12.
[31] Response to Liberty Data Request #12.
[32] Response to Liberty Data Request #12.
[33] Liberty notes that also applying short-term ratings to other transmission elements may give system operators additional flexibility in mitigating emergency system conditions.

percent for winter normal conditions, and up to 135 percent for winter emergency conditions. However, for operating purposes, the Companies use a program that indicates allowed loading based on actual or expected ambient temperatures. The Companies reported that they include any rating limitations caused by transformer leads.[34]

High Voltage Circuit Breakers, Current Limiting Reactors, and Wave Traps

LG&E/KU operates its high voltage circuit breakers at the manufacturers' continuous current ratings for ambient temperatures from -30° C to +40° C, current limiting reactors from -5° C to +40° C, and wave traps up to 45° C for one hour, so long as the mean 24 hour temperature does not exceed 40° C.[35]

Current Transformers and Protective Relays

The Companies rate current transformers, including bushing current transformers, to operate at the manufacturers' continuous rating so long as the ambient temperature during a 24-hour period does not exceed 40° C and does not average more than 30° C. They derive emergency ratings from a formula based on the rating of the current transformer tap being used. The Companies design protective relay schemes to limit the continuous current flowing through a relay to 5 amperes, if possible. However, if this limit is exceeded because of available current transformer ratios, the continuous current is limited to the manufacturer's rating.[36]

3. Analysis

LG&E/KU rates each of its transmission system components individually. All transmission system components are included in the rating of each line and bus. The rating of the component (i.e., conductor, switch, wave trap, current transformer) that most limits the safe operating level of the transmission line or bus segment becomes the rating of that facility. LG&E/KU uses continuous normal and emergency ratings at different allowable operating temperatures in the design of its system. The rating of the specific transmission components is compatible with this rating philosophy and the philosophy is consistently applied.

Many transmission lines in the LG&E/KU system were constructed to operate at temperatures less than 176° F. LG&E/KU does not perform inspections or calculations to assure compliance with the NESC until a line will be operated above 176° F because it has historically found few problems when it made such inspections or calculations. Liberty suggests that to be in conformance with the NESC, the Companies perform inspections or calculations on a line-specific basis when that line is to be operated above its original design temperature.

Liberty found that the LG&E/KU transmission equipment thermal rating planning methods include all system elements, have sufficient coordination, and are appropriately conservative.

[34] Interview of May 13, 2005.
[35] Response to Liberty Data Request #12.
[36] Response to Liberty Data Request #12.

D. Fault Timing Analysis

1. Definition

Liberty reviewed the fault duration and equipment operating times used in the transient stability analysis to determine whether reasonable values were used.

2. Discussion

Utilities perform transient stability studies to ensure that generators remain synchronized to the system during faulted conditions. These studies simulate various types of faults on the transmission system and the response of protective equipment such as circuit breakers. The analyst must know the response time of the protective relay systems and circuit breakers to properly simulate faults on the system. The model must reflect whether equipment is gang-operated[37] or operated on an independent pole basis.[38] The application of high speed reclosing,[39] sync-check reclosing,[40] or dead-line reclosing,[41] and the configuration of the bus also must be taken into account.

Various types of faults can occur on a power system. Generally speaking, a three-phase fault is more severe than a single-phase-to-ground fault, and faults that involve delayed clearing[42] are more severe than those that are cleared in normal time.[43] These faults can occur on lines, transformers, buses, or circuit breakers with varying system interruptions resulting.

[37] Gang-operated means that the three phases of a switch or circuit breaker are mechanically coupled and generally operate in tandem or by a single trip coil (or a single set of two redundant trip coils).
[38] Independent pole operation occurs where each phase of equipment such as a circuit breaker has its own trip coil (or set of two trip coils) so it may operate independently of the other phases.
[39] High speed reclosing on the transmission system is where a line is closed back within approximately one-half second after it trips without regard for system voltage on either side of the breaker.
[40] Sync-check reclosing is where both sides of the circuit breaker must be at system voltage before the breaker is closed. This type of reclosing is generally used at generating stations to prevent damage to the generators for close in faults.
[41] Dead-line reclosing is where no automatic high speed or sync-check reclosing takes place; rather a manual closure of the circuit breaker is initiated some time after the fault has cleared.
[42] A fault that involves delayed clearing occurs when a circuit beaker failed to operate as it should have and this requires additional time for backup protective equipment to operate to clear the fault. Additional facilities beyond the faulted facility will also be required to be removed from service.
[43] A fault cleared in normal time is one where protective equipment operates properly and only the faulted element is removed from service.

All of LG&E/KU's 345 kV circuit breakers are independent pole breakers. LG&E/KU also stated that their 345 kV transmission system is designed either as breaker and one-half substations[44] or will be in the future, and that only transformers or minimum loads are connected to the bus positions.[45]

LG&E/KU's 138 kV system is predominately a straight bus[46] design; however, the design of each new 138 kV substation is reviewed and some are being constructed as a breaker and one-half design for system reliability.[47]

LG&E/KU stated that the 345 kV breakers are simulated to operate in 4 cycles (2 cycle relay time and 2 cycle guaranteed breaker operating time) and that the delayed clearing times are in the 8 to 9 cycle range. Breaker failure times may be higher than the 8 to 9 cycles in some cases to provide additional margin against misoperation; however they are always set lower than the critical clearing time.[48,49]

In conducting the stability studies, LG&E/KU instructed MISO to only simulate three-phase, normally cleared faults and three-phase faults accompanied by a single pole stuck breaker on the 345 kV system. In addition, MISO was to use the normal clearing time of 4 cycles for three-phase faults and a total clearing time of 17 cycles for faults involving breaker failure. If it encountered instability, MISO was to reduce the fault duration by one-half cycle until it restored system stability. LG&E/KU stated that this would test the strength of the system.[50] In testing the four transmission options and the base case without TC2, only three unstable cases resulted from the 17 cycle stuck breaker time testing. The lowest critical clearing time identified was 13.5 cycles which is well above the 8 to 9 cycle time normally used for breaker failure relay schemes.[51]

3. Analysis

By instruction LG&E/KU, MISO did not run studies with 138 kV faults or with faults simulating reclosing of any kind. MISO simulated three-phase, normally-cleared faults and three-phase faults accompanied by a single-pole stuck breaker with 17 cycle total clearing time at every bus

[44] Breaker and one-half substations have bus layouts with groups of three breakers and two line positions between two buses. The buses are connected to other "three breakers – two line positions" groups. LG&E/KU sometimes connects step-down transformers to the buses. A ring bus layout usually has no common buses but has a breaker between each line position (the number of breakers is equal to the number of line positions) to form a ring where each line position is connected by two breakers. Each line position for straight bus layouts is connected to one common bus by one breaker. For both breaker and one-half bus and ring bus layouts, a breaker can be opened without de-energizing a line (this is not true for straight bus layouts). However, for the failure of a breaker in breaker and one-half layouts, only one line position may, in some cases, be affected. For the failure of a breaker in ring bus layouts, two line positions will always be affected. Failure of a breaker in straight bus layouts affects all line positions.

[45] Interview of May 12, 2005.

[46] A straight bus is where many line positions are connected to a single bus. It is inherently less desirable from a reliability viewpoint in that the failure of a circuit breaker causes many elements to be removed from service.

[47] Interview of May 12, 2005.

[48] The critical clearing time at a substation is the maximum time that the most severe fault at that substation can remain connected to the system without causing system instability.

[49] Interview of May 17, 2005.

[50] Interview of May 17, 2005.

[51] Response to Liberty Data Request #10, Appendices to G218 Report provided as Exhibit MSJ-2.

on the LG&E/KU system and at 345 kV buses adjoining the LG&E/KU system. MISO used 4-cycle timing consisting of 2-cycle relay time and 2-cycle guaranteed circuit breaker time for normally cleared 345 kV faults. Four cycles is typical of clearing times for this type of fault at 345 kV. Stuck breaker timing of 8 to 9 cycles allows for the tripping process to be repeated, time to sense and communicate the stuck breaker condition to backup facilities, and a small time margin. Values of 8 to 9 cycles are typical of that used in the industry for 345 kV applications. The use of 17 cycle total delayed clearing time for a stuck breaker represents worst case condition analysis.

Liberty found that the fault durations and equipment times for the faults simulated in the MISO transient stability studies were reasonable, conservative, and similar to times used in the industry.

E. Load Forecasting

1. Definition

Liberty reviewed LG&E/KU's load forecasting methods on both a system and sub-system basis to assess whether they represented the future in a reasonable manner. Items reviewed included the use of weather-based forecasting and the weather inputs to the forecast. Liberty also reviewed the econometric model assumptions used in load forecasting.

2. Discussion

General

LG&E/KU separately and jointly forecast system electrical energy sales, use-per-customer, and electrical loads and demands using externally and internally sourced economic and demographic modeling, along with specific growth outlooks from large customers.[52] The Companies develop rolling, medium-term 1- to 5-year forecasts using monthly derived data and long-term 6- to 15-year forecasts generally using annual or seasonally derived data.[53] These forecasts have an equal probability of being exceeded or not reached and are known as 50/50 forecasts. To better assure reasonable accuracy and sensitivity in the forecasts, LG&E/KU use econometric models to establish the historical relationships between electric sales, loads, and demands and those variables that affect sales development within the LG&E and KU service areas. Although the energy sales forecasts are used for financial reasons, the load and demand forecasts are used as the basis for logically and strategically planning generating and transmission facilities. This is conducted jointly and for each company in order to serve the Companies' Kentucky base loads, as well to provide a reserve margin.[54] No other LG&E/KU organization performs load forecasting or sub-area forecasting using the econometric models.[55]

[52] LG&E/KU Responded to Liberty Data Requests #1 through #3 by incorporating by reference their 2005 IRP, Case No. 2005-00162.
[53] 2005 IRP, Case No. 2005-00162, Vol. I, page 5-7.
[54] 2005 IRP, Case No. 2005-00162, Vol. I, page 5-5.
[55] Interview of May 12, 2005.

LG&E/KU's forecasting group (Market Analysis and Valuation), sometimes assisted by the planning and engineering groups, is responsible for energy sales modeling, for system load forecasting and annual updates, for verifying the appropriateness of modeling and forecasting, for resource assessment, and for resource acquisition planning. LG&E/KU's planning group, after adjusting for company energy use and line losses and scaling the 50/50 load and demand forecasts to substation buses, supplies the load and demand forecasts to MISO for use in LG&E/KU, MISO, and ECAR load flow studies. Load forecast data are also supplied to NERC for incorporation into the MMWG model.[56] These studies are used to evaluate system reinforcement options based on forecast need, and the affect of these options on other transmission systems.[57]

LG&E/KU reported that the transition from the medium-term to long-term load forecasts has been smooth because the economic and demographic growth within the service areas has been steady.[58] Robust medium and long term forecasts and resulting load flow and demand studies is vital for LG&E/KU to justify the need to develop resources and to allow them make optimum planning and operating decisions.[59] LG&E/KU reported that it is planning, or is taking actions, to improve the reliability and efficiency of its existing and aging generating facilities, and to modify generating facilities to comply with present and future pollution regulations, and retiring or reducing the use of less reliable and less efficient generator facilities. Some of the units are approaching or exceeding life expectancies and may be retired because of economic considerations.[60]

LG&E/KU's 2005 Integrated Resource Plan (*IRP*) included the following plans and assessments to serve customer load:[61]

- Planning maintenance, upgrade, and operating actions to optimize the reliability and operating efficiencies of existing generating units, some of which are approaching or have exceeded life expectancies
- Installing additional capacitors on their distribution system to improve system capacity and reduce line and transformer losses
- Assessing purchase power agreements
- Assessing demand-side program options such as smart thermostats
- Assessing supply-side options, such as installing new generators or upgrading old units, considering on-going and potential pollution regulations
- Determining optimum generation, transmission, and substation projects necessary to serve the Companies' native loads and provide a 12-14 percent reserve margin.

LG&E/KU uses a software package for evaluating cost effectiveness of various resource expansion options under various case conditions.[62]

[56] Interview of May 17, 2005.
[57] Interview of May 12, 2005.
[58] Interview of May 12, 2005.
[59] 2005 IRP, Case No. 2005-00162, Vol. I, page 5-5.
[60] 2005 IRP, Case No. 2005-00162, Vol. I, page 8-118.
[61] 2005 IRP, Case No. 2005-00162, Vol. I, page 5-4.
[62] 2005 IRP, Case No. 2005-00162, Vol. I, page 5-12.

2004 Load

In the summer of 2004, LG&E/KU's net generating capacity was 7,610 megawatts and the scheduled purchases from others totaled 527 megawatts. The combined system peak demand was 6,513 megawatts. The planned reserve margin at that time was 26.4 percent. However, because of a mild summer, the actual margin was 30.4 percent.[63] LG&E/KU reported that climatic data indicate that recent winters have been warmer than normal, while the summers have been cooler than normal.[64] Although LG&E/KU's 2004 capacity was more than adequate, it reported that, based on its 2004 combined load forecast, up to 552 megawatts of additional capacity will be needed by 2012 to optimally serve forecast native loads while maintaining its planned reserve margin of 13 to 15 percent.[65] LG&E/KU indicated that this margin level would be sufficient to provide reliable service even if unexpected loss of generation, extreme weather conditions, or unanticipated load growth occurs.[66]

Modeling and Load Forecasting

In 2002, both LG&E and KU were using the same economic and demographic methods for modeling loads. In 2004, the Companies integrated their load forecasting methods.[67] KU's load forecasts also include its Old Dominion Power load (about 5 percent of the KU load) in Virginia and the wholesale loads of 11 municipals and Berea College.[68]

In 2005, LG&E/KU reduced the overall level of its integrated medium and long-term energy forecasts, prepared in 2002, by about 3 percent because of the effects of national economic weakness occurring 2001. Although this allows the new Trimble County 2 generator schedule to be deferred from 2007 to 2010, the average annual increase of combined load growth from 2005 to 2019 continues to be about 2.0 percent, the same rate of growth as forecasted in 2002.[69]

LG&E/KU's load forecasts include full-service residential, general residential, commercial, industrial, mine, lighting, and wholesale classes, as appropriate for each Company.[70] Forecasts are weather-normalized to a 20-year rolling average temperature. LG&E/KU stated that the temperature used for winter forecasting had a 0 percent probability of being exceeded and the temperature used for summer forecasting had a 50 percent probability of being exceeded.[71]

LG&E/KU forecasts residential, and to some degree commercial, energy sales and load growth by modeling economic and demographic national trends, such as gross domestic product, consumer prices, and industrial productivity, and by modeling local trends, such as local population trends, employment, personal income, weather, electricity cost, end-use analyses of heating and cooling, and appliance use trends. In general, monthly data are used for modeling the Companies' medium-term forecasts, and annual or seasonal data are used for modeling the long-

[63] 2005 IRP, Case No. 2005-00162, Vol. I, pages 8-109 and 8-110.
[64] Interview of May 12, 2005.
[65] 2005 IRP, Case No. 2005-00162, Vol. III, Reserve Margin Analysis, page 19.
[66] Interview of May 12, 2005.
[67] Interview of May 12, 2005.
[68] 2005 IRP, Case No. 2005-00162, Vol. I, page 5-1, and Interview of May 12, 2005.
[69] 2005 IRP, Case No. 2005-00162, Vol. I, pages 6-3 and 6-4.
[70] 2005 IRP, Case No. 2005-00162, Vol. I, page 7-7 and Interview of May 12, 2005.
[71] Interview of May 12, 2005.

term forecasts.[72] The LG&E/KU industrial load model's explanatory variables include real service territory industrial value-added, the real average price of electricity, and weather. Specific large industrial customers are individually forecast, based on sales and demand history, and on the customer's outlook for growth and expansion.[73]

Economic and demographic assumptions for forecast drivers are developed for each county within each utility using the Kentucky Econometric Model and the LG&E/KU Service Territory Econometric Model. Separate overall LG&E and KU forecasts, and a combined LG&E/KU forecast, are developed. Forecasts are not developed for sub-areas. The exception is that the loads within a county are adjusted if the entire county is not served by LG&E or KU.[74] The Companies use the University of Kentucky's Gatton Center for Business and Economic Research to help develop local economic and demographic forecasts, using national macroeconomic data provided by Global Insight. Historical weather data are obtained from the National Climatic Data Center. Fuel costs are modeled using NYMEX future prices for gas and oil. Hill & Associates provides coal production forecasts for modeling coal mine sales. Itron provides regional databases to support modeling of appliance saturation and efficiency trends. Historical load profile and load factor data are determined internally. Industrial growth expectations come from regular discussions with large customers. Historical sales data for industrial and for respective classes come from the Companies' customer information systems.[75]

The following key economic and demographic assumptions were made for the primary drivers of the Companies' energy forecasts:[76]

- The weather over the next 15 years will be average as compared with the previous 20 years
- The annual US Real Gross Domestic Product growth will average 3.4 percent over the next 5 years and 3.1 percent over the 15-year forecast horizon
- The KU service area population will increase annually, on average, by 0.8 percent over the 15-year horizon; and the LG&E service area population will increase annually by 0.5 percent over the next 5 years, and 0.6 percent over the 15-year forecast horizon
- The households in the KU served counties will increase annually, on average, by 1.3 percent over the next 5 years and 1.1 percent annually over the 15-year forecast horizon. The annual increase of households served by LG&E will average 0.8 percent over the 15-year forecast horizon
- Real per capita personal income in the Louisville metro area will increase annually, on average, 3.5 percent over the 15-year forecast horizon
- KU service territory commercial employment will increase annually, on average, by 2.4 percent over the next 5 years and 2.1 percent annually over the 15-year forecast horizon. LG&E service territory commercial employment will increase annually by 2.3 percent over the 15-year forecast horizon
- KU's industrial value-added will increase annually, on average, by 4.3 percent over the next 5 years and 3.4 percent annually over the 15-year forecast horizon

[72] 2005 IRP, Case No. 2005-00162, Vol. I, pages 5-8 and 5-9.
[73] 2005 IRP, Case No. 2005-00162, Vol. II, KU Forecast Report, page 50.
[74] Interview of May 12, 2005.
[75] 2005 IRP, Case No. 2005-00162, Vol. I, page 5-9.
[76] 2005 IRP, Case No. 2005-00162, Vol. I, pages 7-15 and 7-37.

- Annual coal production will increase annually, on average, by 3.0 percent over the next 5 years and 2.3 percent annual over the 15-year forecast horizon.

The planning and engineering organizations, after adjusting for company energy use and line losses, scale the company-wide 50/50 load and demand forecasts developed from each company's model to each substation bus.[77,78] LG&E/KU does not centrally forecast reactive load requirements. System planners make reactive load forecasts for use in planning studies.[79,80]

LG&E/KU forecasts annual peak demand, adjusted for line losses and interruptible loads, via a process in which forecast calendar year energy sales are converted to forecast monthly loads, based on 20-year historical month-to-year ratios, then converted to forecast hourly demand based on the 10-year historical averaged and weather-normalized monthly load duration and hourly chronological curves. The Companies' combined annual peak coincidental demand generally occurs during July. However, the winter peak load is of a similar value.[81]

To address uncertainty caused by deviations from normal weather and assumed economic assumptions, LG&E/KU develops statistically based low growth rate and high growth rate scenarios. For the low growth scenario, the forecast year-over-year base growth is reduced by the difference between the 50^{th} percentile values and the 33^{rd} percentile values. For the high growth rate scenario, the forecast base growth is increased by the difference between the 50^{th} percentile values and the 67^{th} percentile.[82] LG&E/KU indicated that it also forecasts coal, oil, and gas costs using statistical deviations from expected costs.

All forecasts of energy sales, demand, and use-per customer are based on normal, or average, weather. The Companies use a rolling average daily temperature of the previous 20 years for their forecasts.[83] The Companies indicated that future winter temperatures should not be lower than average used for the forecast. However, there is a 50 percent chance that the average summer daily temperatures would be exceeded. The Companies said that weather hotter than normal, even on the summer peak demand day, only causes minor deviation, about 1 percent, from the base forecast. Therefore, the high growth scenario forecast should account for the deviation caused by excessively hot weather.[84]

The Companies reported that they are required to explain to the parent company any differences between monthly forecast and actual loads, and to evaluate on an annual basis, the sensitivity of the explanatory variables in order to adequately explain the behavior of their customer and sales data. This includes evaluation of the impact of new appliances, technologies, and regulations.[85]

---

[77] Although the planning and engineering groups are adjusting the forecasts to the substation level, it is being done without the benefit of econometric models and may not be consistent in all planning sub areas. In addition, scaling loads downward to fit the corporate forecast may distort transmission requirements at the local level due to diversity.
[78] Interview of May 12, 2005.
[79] Interview of May 12, 2005.
[80] Of note, the Companies have an on-going capacitor installation program for improving transmission system power-factor as well as improving system capacity and efficiency.
[81] 2005 IRP, Case No. 2005-00162, Vol. II, Energy Requirements and Demand Forecast, pages 11-14.
[82] 2005 IRP, Case No. 2005-00162, Vol. I, page7-40 and Vol. II, KU Forecast, page 76.
[83] 2005 IRP, Case No. 2005-00162, Vol. I, page. 5-14.
[84] Interview of May 13, 2005.
[85] Interview of May 12, 2005.

3. Analysis

LG&E/KU's forecasts are primarily based on growth in the use of electric energy derived from economic and demographic data obtained from professional sources. The Companies monitor the adequacy of the forecasts by comparing the actual and forecast loads monthly, and by annually evaluating whether the models are sufficiently robust. As expected, the medium-term residential and commercial forecasts use more rigorous modeling, based on monthly data, than long-term forecasting, based on annual or seasonal data. The length of the medium-term and long-term forecasts are of appropriate length for identifying bulk transmission reinforcement needs, especially for LG&E/KU, which has only about 2 percent combined annual load growth.

Liberty found that LG&E/KU's load forecasting methods, econometric inputs, adjustments, and inclusion of demand-side contributions are reasonable and adequate for company-wide transmission reinforcement studies[86] and that reasonable study results would be produced.

F. Technical Analysis

1. Definition

Liberty reviewed the power flow,[87] transient stability,[88] and other technical analyses used to justify the project. These other technical analyses could include reactive requirements or short circuit analysis.[89] Liberty reviewed the size of the system model used for the analysis to determine if it was of sufficient size and of sufficient detail to produce valid study results, the application of the reliability criteria to assure proper simulations, and the results themselves to ascertain whether LG&E/KU or the MISO drew proper conclusions from its analysis.

2. Discussion

MISO has the responsibility for performing the analyses of delivery service and generation interconnection requirements. Delivery service requirements analysis focuses on thermal and

[86] Liberty notes that prorating the 50/50 load forecast to all system buses will result in insufficient load being modeled for local area planning studies due to inverse diversity.

[87] Power flow analysis is done with a mathematical impedance model of the power system. Final or steady state (when angular change between generators has ceased) voltages are calculated at nodes and power flows are calculated on the various pieces of equipment. Contingencies are simulated to ensure that equipment loadings and voltages stay within prescribed limits.

[88] Transient stability analysis is done with a mathematical impedance model of the system but also includes time in the calculation. Usually the time varying component is .01 seconds and the analysis is simulated to about 2 seconds. Various faults are modeled on the system with their associated clearing times and equipment taken out of service. A power flow analysis is performed at each time increment and voltages, power flows, and angular differences between generators are calculated. These time changing power flows, voltages and angular differences produce a speed change at generators. If a generator cannot remain within certain speed limits, it becomes unstable and is automatically tripped off line.

[89] When faults occur on the power system, short circuits are created and large amounts of current flows to the fault. To isolate the faulted element, power system protective devices must interrupt the current that is flowing into the fault. The power system is mathematically modeled so that the amount of current flowing into the fault is calculated. Power system protection equipment can only interrupt finite current values. Interruption of faults above the rated value of the equipment can cause damage to the protective equipment.

voltage issues, while interconnection requirements analysis focuses on stability, short circuit, and congestion[90] issues. MISO also relies on its own previous studies and the studies done by its members. In the instant case, these studies conducted by members include the preliminary analysis performed by LG&E/KU to identify various potential options for the interconnection of TC2, as well as stability studies previously conducted by MISO.[91]

In determining the optimum system requirements for integrating the new TC2 unit into the power system, MISO performed all power flow, transient and long term[92] stability, and short circuit studies that were required. LG&E/KU performed an internal short circuit analysis to verify the short circuit results obtained by MISO for Option #4, and validated those results.[93] Liberty only discusses the studies done by MISO for LG&E/KU in this report. Table II.3 below lists the various analyses performed by the MISO for TC2, the study type, and the dates they were performed.

Table II.3
List of MISO Analyses

MISO Study Name and Number	Year and Load Simulated	Study Type	Company Performed For	Date
Generator Interconnection Evaluation - G218	2007 Peak	Stability Short Circuit 4 Options	LG&E/KU	3/11/03
System Impact Study, 750 MW Transmission Service to LG&E/KU – A024	2007 Peak 2007 Shoulder	Power Flow 4 Options 100% and 75% Delivery Amounts	LG&E/KU	5/1/03
Generation Interconnection Facility Study Report - G218	N/A	Costing – Stability, Option #4	LG&E/KU	7/10/03
Facility Study Report – F012	N/A	Costing – Power Flow, Option #4	LG&E/KU	7/15/03
System Impact Study, Firm Point to Point Transmission Service – A099	2007 Peak	Power Flow	IMPA*	9/10/04
System Impact Study , Firm Network Service – A091	2007 Peak 2009 Peak	Power Flow	IMEA**	9/10/04
Trimble County Prior Outage Study, Supplement to F012	2007 Peak	Security Assessment with One Line Out	LG&E/KU	2004

* Indiana Municipal Power Agency
** Illinois Municipal Electric Agency

[90] Congestion refers to the places in a free flowing power system where economic operation would require that more power should flow than is actually able to flow.
[91] Interview of May 17, 2005.
[92] Long-term stability analysis is stability analysis that is performed out to 15 to 20 seconds or longer. This analysis captures the feedback actions of generator controls that do not react in the first few seconds of the simulation.
[93] Interview of May 12, 2005.

Power Flow Analysis

Liberty reviewed the power flow model used by MISO to conduct its analyses to ensure that the model was a reasonable representation of the system and of sufficient detail to produce valid study results. MISO uses the Power Technologies Inc. (*PTI*) Power System Simulator/Engineering (*PSS/E*) power flow program.[94] This program is used industry wide for power flow modeling and represents state of the art modeling software.

MISO began with the full 60,000 bus MMWG model without equivalents.[95] The 2007 summer peak and shoulder period (75 percent to 80 percent of peak load) were studied. In the MMWG model, the coincident peak load for each control area is represented. LG&E/KU is its own control area, and therefore its 100 percent load forecast as supplied to the MMWG was represented. The transmission system outside of LG&E/KU was represented down to the 138 kV/115 kV level. Transmission on the LG&E/KU system was modeled down to the 69 kV level with two point[96] buses made into an equivalent, except for the first bus in at the end of the line. In this manner the validity of power flows on the 69 kV transmission system were preserved. [97]

When MISO performs its thermal or stability analyses, it does so through ad hoc study groups. These groups consist of subject matter experts from MISO, the utility requesting the analysis (LG&E/KU), and the surrounding control areas. The ad hoc study group formed for the power flow analysis reviewed the options identified by the LG&E/KU preliminary analysis and came to the conclusion that additional viable options did not exist.[98]

Generation bias was included in the cases by first using the merit order[99] dispatch on the LG&E/KU system. TC2 was added, with combustion turbines reduced at the Brown generating station by a similar amount. Additional generation bias occurs when generation contingencies are modeled. Loads on the system were modeled as constant impedance.[100,101]

The base case with TC2 included and the inclusion of overloaded facilities and voltage violations were identified. Each of the four options was also tested for overloads and voltage violations. MISO performed two analyses. The first analysis was a screening analysis. A DC tool (neglects voltage) was used to identify circuits over 100 kV[102] that would be loaded to 80 percent or higher for all N-1 contingencies in MISO's control area and all surrounding control areas. Contingency lists from the outside control areas, including multiple element outages, each generator, and each flowgate (interface or critical element) in MISO were also included in the screening contingencies.[103] In addition, MISO ran the cases required to assure compliance with the more

---

[94] Interview of May 17, 2005.
[95] Liberty notes that computer power has increased to the point where it is more economical to run the larger networks than to expend engineering time to perform equivalents to reduce their size.
[96] Buses with only two network connections.
[97] Interview of May 17, 2005.
[98] Interview of May 17, 2005.
[99] Merit order is removing units from service starting with the most expensive to operate or placing units in service starting with the unit least expensive to operate.
[100] A constant impedance load is one where the real and reactive components are not allowed to change with changes of voltage.
[101] Interview of May 17, 2005.
[102] At the May 17, 2005 interview, LG&E/KU stated that they instructed MISO not to monitor the 69 kV system because any overloads on their 69 kV system would be picked up when local transmission analysis was performed.
[103] Interview of May 17, 2005.

restrictive LG&E/KU reliability standards.[104] The cases that identified transmission lines or transformers operating above the screening limit, or existence of voltage violations of the LG&E/KU reliability standards,[105] were confirmed with standard power flow analysis.

MISO performed contingency analysis on a case that modeled a 750 MW (100 percent) transfer of TC2 to LG&E/KU, and on a case that modeled a 562 MW (75 percent) transfer of TC2 to LG&E/KU. In the 75 percent case, additional combustion turbine generation at Brown was brought on line to preserve inter-control area flows.[106]

MISO stated that the same facilities that were overloaded in the 100 percent transfer case were also overloaded in the 75 percent transfer case.[107] No voltage violations were noted in either the 100 percent or 75 percent transfer cases. MISO also stated that transfers to the Indiana utilities were studied separately and that no Kentucky facilities were found to be overloaded or that no voltage violations of the LG&E/KU reliability standards existed.[108]

Transient and Long Term Stability Analysis

MISO began with the power flow model used in the 2001 ECAR stability model. This power flow model is also a descendent[109] of the MMWG model. The 2007 summer peak load level was studied and all generation and transmission that would be in service by 2007 was added. Data for the new generators was obtained from their respective owners. A full transmission representation of the ECAR region was made, down to the 138 kV/115 kV level, and down to the 69 kV level on the LG&E/KU system, with two point buses made into an equivalent, except for the first bus in at the end of the line. In this manner the validity of power flows on the 69 kV is preserved.[110]

Generation bias was included in the cases by first using the merit order dispatch on the LG&E/KU system. TC2 was added, with combustion turbines reduced at the Brown generating station by a similar amount. Additional generation bias occurs when generation contingencies are modeled. The real portion of the load was modeled as constant current[111] and the reactive[112] portion of the load was modeled as constant admittance.[113]

[104] Response to Liberty Data Request #18.
[105] Interview of May 17, 2005.
[106] Interview of May 17, 2005.
[107] Response to Liberty Data Request #19.
[108] Interview of May 17, 2005.
[109] Two different, but similar power flow models that were constructed from the same base data.
[110] Interview of May 17, 2005.
[111] Modeling the real or resistive load as constant current accounts for load change during power swings as the same amperes of resistive load (like a incandescent light bulb) at a lower voltage will draw less power form the system.
[112] Voltage and current alternate their magnitude 60 times a second in accordance with their sinusoidal waveform. When the angular difference between the two is zero, all power flowing is called "real power" and can be measured in Watts. When the voltage waveform is angularly ahead of the current waveform, power other than Watts is required to supply the power relationship. This power is called "reactive or imaginary" power. In the case described, it is inductive reactive power that is required and this reactive power (lagging) tends to lower system voltage. Similarly, when the current waveform angularly leads the voltage waveform, capacitive reactive power (leading) is required to satisfy the power relationship and system voltage is raised. Reactive power is also referred to as VARs, or Volt Amperes Reactive.
[113] Modeling the reactive portion of the load as constant admittance, or the reciprocal of the reactive portion of impedance, accounts for motor load change during power swings as at a lower voltage, some motors will draw increased power from the system.

All generation connected to the 69 kV system and above was discretely modeled. Smaller generation connected to lower voltage systems was netted with load. Generator step-up transformers were included in the representation. Station service, or auxiliary load, was netted with generator gross output.[114]

MISO uses the PTI PSS/E stability software program for its analysis. This program is used industry wide for transient and long-term stability modeling and represents state of the art modeling software. The stability program also incorporates the PTI power flow program in its software.[115]

MISO also formed an ad hoc working group for the stability analyses it conducted. Similar to the thermal working group, this working group consisted of subject matter experts from MISO, the utility requesting the analysis (LG&E/KU), and the surrounding control areas.[116]

No relays were modeled by MISO. LG&E/KU stated that they perform annual relay coordination studies and that any coordination problems should be resolved there.[117]

Transient stability studies are performed to ensure that generators remain synchronized to the system during faulted conditions. Various types of faults on the transmission system are simulated along with a simulation of the response of protective equipment such as circuit breakers. In order to perform transient stability analysis, the response time of the protective relay systems and circuit breakers must be known and modeled. In addition, some equipment may be gang operated and other equipment may operate on an independent pole basis. The application of high-speed reclosing, sync-check reclosing, or dead-line reclosing and the configuration of the bus also have timing considerations.

The types of faults that can occur on the power system are varied. Generally speaking, a three-phase fault is more severe than a single-phase-to-ground fault, and faults that involve delayed clearing are more severe than those that are cleared in normal time. These faults can occur on lines, transformers, buses, or circuit breakers with varying system interruptions resulting.

LG&E/KU stated that all of its 345 kV circuit breakers are independent pole breakers with two trip coils.[118] LG&E/KU also stated that its 345 kV transmission system substations are designed either as breaker and one-half layouts, or will be so designed in the future, and that only transformers or minimum loads are connected to the bus positions. All DC power in the substation for relay and circuit breaker operation is provided by one station battery. LG&E/KU does not design its system to withstand a battery outage as a single contingency.[119]

[114] Interview of May 17, 2005.
[115] Interview of May 17, 2005.
[116] Interview of May 17, 2005.
[117] Interview of May 17, 2005.
[118] One trip coil is used for each independent high speed relaying system.
[119] Interview of May 12, 2005.

LG&E/KU uses dual primary high speed directional comparison blocking[120] and permissive overreaching transfer tripping[121] schemes for protecting its 345 kV lines from faults. These systems are backed up with time-delay, ground-overcurrent zone 2 and zone 3 relays. The redundant primary relays at each end of a line determine whether a fault is on the protected line or on adjacent lines. If the fault is on the protected line, the relays cause the circuit breakers at both ends of the line to trip instantaneously, either by not receiving a block signal from the far end relays (directional comparison blocking scheme) or by receiving a trip signal from the far end relays (permissive overreaching transfer tripping scheme). If primary relays on the protected line fail to operate as intended, the backup relays[122] will cause the fault to be cleared after some specified time delay. The blocking scheme and the back up relays provide reliability and the transfer trip scheme provides security.

LG&E/KU stated that the 138 kV system is predominately a straight bus design, however, it reviews the design of each new 138 kV substation and constructs some as a breaker and one-half design for increased reliability.[123]

LG&E/KU uses one high speed directional comparison blocking scheme as primary protection for each of its 138 kV lines. Each primary system is backed up with a ground overcurrent relaying scheme. Although the primary 138 kV relay scheme causes immediate tripping for line faults, these high speed relays are not redundant as is the 345 kV primary relaying and has a greater chance of misoperation than does the 345 kV relaying. The 138 kV circuit breakers breaker failure and reclosing schemes are of the same design as those used for 345 kV.[124]

Most of LG&E/KU relays are the older electromechanical types that require periodic inspection, testing, and maintenance. LG&E/KU reported that it performs transmission relay maintenance on a 5-year cycle.[125,126]

To accommodate the installation of the double circuit 345 kV lines from Trimble County to tap the Speed to Ghent 345 kV line (Case No. 2005-00155), four 345 kV circuit breakers will be installed in the 345 kV Trimble County substation's breaker and one-half bus scheme. Two breakers are required for TC2 and one breaker each is required for the two 345 kV lines that tap the Speed to Ghent 345 kV line.[127]

---

[120] Relays used for directional comparison schemes determine the direction of the fault current, and they also measure the impedance of the fault to identify approximate fault location. Directional comparison blocking schemes identify faults up to and past (overreach) the far end of a line. A relay trip is blocked, via power line carrier (PLC), when a relay at the far end determines that the fault is not in the direction of the line protected. During PLC problems, these relays will trip for all faults on the protected line. However, they may also trip for some faults on the adjacent lines.

[121] Permissive overreaching transfer-trip relays detect faults up to and past the far end of a line. The relays measure direction, but not distance, and operate only when the fault current at each end of the line are in opposite directions. A relay is only allowed to trip only if it receives a signal, via microwave, from the relay at the far end of the line indicating that the fault is on the protected line and not on an adjacent line.

[122] The back up relays will trip with a time delay for zone 2 phase-to-ground faults up to and slightly past the line far end. Zone 3 faults will be cleared with a slightly longer delay and may operate for faults that are on the next adjacent line, and possibly further.

[123] Interview of May 12, 2005.

[124] Interview of May 12, 2005.

[125] Interview of May 12, 2005.

[126] Liberty notes that while the 5-year cycle is satisfactory with ECAR, other reliability councils require utilities to maintain their 345 kV electromechanical relays on a 2-year cycle.

[127] Response to Liberty Data Request #7.

To accommodate the installation of the Mill Creek to Hardin County 345 kV line (Case No. 2005-00142), only one additional 345 kV circuit breaker is needed to connect the new Hardin County line onto the breaker and one-half scheme at the Mill Creek substation. The Hardin County 345 kV substation presently does not have any circuit breakers. However, a breaker and one-half scheme is planned to be eventually installed. Four 345 kV breakers will be installed with the installation of the second Hardin County 345/138 kV autotransformer prior to the installation of TC2. One additional 345 kV breaker will be needed at Hardin County to connect the new Mill Creek line. At that time, the Hardin County substation will be a 5 breaker ring bus.[128]

To accommodate the installation of the West Frankfort to Tyrone 138 kV line (Case No. 2005-00154), an additional 138 kV circuit breaker will be installed on the straight bus at Tyrone for the West Frankfort line. The bus at the West Frankfort substation will be converted from a straight bus to a breaker and one-half bus layout with the installation of 3-138 kV circuit breakers when the Tyrone line is connected. At that time, the West Frankfort substation will be a 4 breaker ring bus.[129]

Proposed bus layouts for the 138 kV West Lexington and Higby Hill substations were not available. Bus layouts for the 345 kV Ghent and Speed Tap substations were also not available, however the MISO represented that the Ghent 345 kV substation was a full breaker and one-half substation with approximately 7 connections between the buses and that the Speed 345 kV substation was essentially a tap on the 345 kV line.[130]

LG&E/KU stated that the 345 kV breakers are simulated to operate in 4 cycles (2 cycle relay time and 2 cycle guaranteed breaker operating time) and that delayed clearing times are in the 8 to 9 cycle range. Breaker failure times may be set higher than the 8 to 9 cycles in some cases to provide additional margin against misoperation, however they are always set lower than the critical clearing time.[131,132]

In conducting stability studies, LG&E/KU instructed MISO to only simulate three-phase, normally cleared faults and three-phase faults accompanied by a single pole stuck breaker[133] on the 345 kV system. In addition, MISO was to use the normal clearing time of 4 cycles for three phase faults and a total clearing time of 17 cycles for faults involving breaker failure. If it encountered instability, MISO was to reduce the fault duration by one-half cycle until it restored system stability. LG&E/KU stated that this worst case analysis process would test the strength of the system.[134] MISO did not run lesser faults, such as reclosing simulations or faults on the 138 kV system.

MISO conducted stability studies for the base case without TC2 and for the four options that were previously identified. MISO simulated normally cleared faults and delayed cleared faults at

[128] Response to Liberty Data Request #7.
[129] Response to Liberty Data Request #7.
[130] Interview of May 18, 2005.
[131] The critical clearing time at a substation is the maximum time that the most severe fault at that substation can remain connected to the system without causing system instability.
[132] Interview of May 17, 2005.
[133] A more severe standard than required by LG&E/KU reliability standards without controlled loss of load on a portion of the system.
[134] Interview of May 17, 2005.

all 345 kV buses on the LG&E/KU system and at all 345 kV buses adjoining the LG&E/KU system. Virtually all faults of consequence at each substation were simulated. All faults were simulated to a duration of 10 seconds. In testing the 4 transmission options and the base case without TC2, only three unstable cases resulted from the 17 cycle stuck breaker time testing. The lowest critical clearing time identified was 13.5 cycles, which is well above the 8 to 9 cycle time normally used for breaker failure relay schemes.[135]

Cascading Outage Analysis

MISO performed cascading outage analysis as part of the stability analysis.[136] MISO was instructed to use the LG&E/KU reliability standards in this analysis.[137] The LG&E/KU standards are more restrictive than those adopted by ECAR. The MISO used emergency ratings in this analysis.[138]

LG&E/KU uses 100^{o} C continuous ratings when it develops its emergency ratings. By using continuous equipment ratings, thermal cascading outages are averted if no overloads are exhibited.

A DC tool[139] was used to perform the cascading analysis for the four transmission options.[140] Various N-2 events were modeled for the LG&E/KU and surrounding control areas. The analysis identified a limited number of 230 kV elements that were shown to be overloaded in all options. The ad hoc working group concurred that the loading on these facilities was due to local conditions and not the due to the installation of TC2. No other overloads were identified.[141]

Short Circuit Analysis

Liberty reviewed the short circuit model used by MISO to conduct its analyses to ensure that the model was a reasonable representation of the system and of sufficient detail to produce valid study results. MISO uses the PTI PSS/E short circuit program for its analyses.[142] This program is used industry wide for power flow modeling and represents state of the art modeling software.

MISO started with a short circuit model that was developed by ECAR in 2001. The system represented in this model was the total ECAR system. All transmission elements above 100 kV were modeled and in the LG&E/KU system, all transmission of 69 kV and above was modeled. All facilities that were expected to be in service by 2007 were added. New facilities that were not included in the ECAR case were modeled with "typical" data developed by industry rules of

[135] Response to Liberty Data Request #10, Appendices to G218 Report provided as Exhibit MSJ-2.
[136] A cascading outage is one where one outage causes another system element to overload and trip or trip due to low voltage and the tripping of the second element causes a third to trip, etc. The August 2003 blackout was such an event.
[137] Interview of May 12, 2005.
[138] Interview of May 17, 2005.
[139] Only the resistive portion of the system impedance is modeled. This allows for a quick calculation of power flows without consideration of voltage.
[140] While one may argue that voltages should have been studied in this analysis, Liberty notes that in general, low voltages are not present if the power system is operating within the emergency limits of its components.
[141] Interview of May 17, 2005.
[142] Interview of May 17, 2005.

thumb. All generation was assumed in service and all ground sources were modeled as in service.[143]

LG&E/KU and other parties validated the newly constructed short circuit model.[144] MISO used this model to develop the short circuit impedances that were required for the stability analysis.[145] MISO evaluated the four transmission options that were identified for the integration of TC2 into the system. Manufacturers provided interrupting ratings for circuit breakers. LG&E/KU planners used 100 percent of the manufacturers' interrupting ratings in short-circuit studies to identify conditions where circuit breaker interrupting ratings were exceeded.[146]

Both three-phase and line-to-ground bus faults were simulated at all buses on the LG&E/KU and neighboring systems for all lines under all conditions. MISO did not perform line out simulations.[147] MISO tabulated all cases where fault current increased by 5 percent or more from base case conditions.[148] It was determined that fault duty on one 345 kV circuit breaker at Clifty Creek substation exceeded the interrupting rating of the circuit breaker. MISO sent the results of the short circuit analysis to all transmission owners for evaluation. American Electric Power responded that the circuit breaker at Clifty Creek was to be replaced prior to the installation of TC2 to resolve other system conditions. Interrupting ratings of all LG&E/KU circuit breakers were not exceeded.[149]

Step and touch potentials caused by short-circuit current can be a safety issue. Addition of new generation and transmission elements reduces system impedance and therefore increases short circuit currents. In addition to assuring that circuit breakers are within their interrupting capabilities, system grounding also needs to be verified. LG&E/KU reported that it verifies that these potentials are within safety limits when new facilities are installed.[150]

Operating Restrictions with Prior Outage Analysis

MISO requires that generation interconnection evaluations include an assessment of simultaneously occurring multiple contingencies to identify constraints that require mitigation. These contingencies are commonly known as overlapping N-I contingencies (N-1-1) or double (N-2) contingencies. This analysis is a security assessment analysis and should not be confused with operating studies that are used to define operating guides.[151] These operating studies will be performed just prior to commercial operation of TC2.[152]

[143] Interview of May 17, 2005.
[144] LG&E/KU stated at the interview of May 12 that they ran internal short circuit studies for validation of MISO Option #4 system.
[145] Interview of May 17, 2005.
[146] Interview of May 17, 2005.
[147] Liberty notes that under rare circumstances, where due to system impedances, fault current may flow out of the bus. A fault with that line out may produce a slightly higher fault current.
[148] Liberty notes that breakers where fault current increased by less than 5 percent could be beyond their interrupting capability. Liberty concurs with MISO that such small increases show that exceeding the interrupting capability of the equipment was not due to the installation of TC2.
[149] Interview of May 17, 2005.
[150] Interview of May 12, 2005.
[151] An operating guide is an action that system operators must take if specified system conditions exist.
[152] Response to Liberty Data Request #18.

MISO used the same model for the prior outage analysis as was used for the power flow analysis. There were some topology and ratings updates that were applied. A 2007 peak load case was modeled. All Trimble County substation outlets were chosen as prior outage facilities and all branches within two buses of the 345 kV bus were selected as the next contingency element.[153]

MISO identified the contingencies for which the operation of TC2 may be restricted or where firm transfer capabilities were impacted. Either system upgrades or operating restrictions will be placed on the unit to mitigate these constraints.[154]

3. Analysis

Liberty reviewed the types of analyses performed by MISO that were necessary to integrate the new TC2 unit into the LG&E/KU transmission system. MISO conducted power flow, transient stability, short circuit, cascading outage, and prior outage analyses. It performed power flow analyses at system peak and at a shoulder load level of 75 percent to 80 percent of peak. In addition, it conducted the power flows studies assuming both a 75 percent and a 100 percent LG&E/KU ownership level of TC2. LG&E/KU ownership was ultimately finalized at the 75 percent level. MISO also performed power flow analyses for the owners of the remaining 25 percent of the TC2 unit.

The Liberty review raised some concerns about MISO's analyses. These were that MISO did not perform light load stability analysis, that the stability analyses may not have been of sufficient length to include long-term dynamic effects, and that all of the analyses may not represent valid study results in view of the delay of the new TC2 from 2007 to 2010. Each of these issues was resolved to Liberty's satisfaction as discussed below.

When a fault is placed on an electric power system, electric angular displacement takes place between the generators supplying power to that system. The electrical movement of the generators is called swing and is a function of the absolute speed of the generator. The generator's speed relative to other generators is also important. If a fault on the electric system is simulated at heavy load, the load on the electric system acts as a damper that will mitigate system swings. At light load levels, there is less of a damping effect and stability swings may be more severe. This concern is mitigated at times of light load levels when peaking and intermediate generation is not on line to contribute to those swings and when the delayed clearing of faults would actually be of much shorter duration than simulated.

Liberty reviewed the stability swing output of the faults that MISO found to be problematic. The response of the LG&E/KU system to those three phase faults that were accompanied by a failed breaker showed that the system period[155] was approximately two seconds.[156] Liberty notes that the system period of some other electric systems, where stability is of heightened concern, is in the order of 6 to 8 seconds. Such a short system period as seen on the LG&E/KU system denotes

[153] Response to Liberty Data Request #18.
[154] Response to Liberty Data Request #18.
[155] The system period is the time it takes for the power system to complete one sinusoidal swing during a disturbance. In general, shorter system periods denote a more highly electrically integrated network that is less susceptible to stability concerns.
[156] Response to Liberty Data Request #10, Appendices to G218 Report provided as Exhibit MSJ-2.

a power system that exhibits strong dynamic damping qualities. Simulating faults that remain on the system for 5 to 8.5 cycles beyond the normal breaker failure operating time of approximately 8.5 cycles produces much higher system generator swings than would actually be encountered. The highest absolute generator swing exhibited with the excessive clearing times was approximately 100 degrees from its initial position.[157] Even under these excessive fault length conditions, Liberty does not consider the magnitude of the generator swings to be of concern. In addition, all of the generators in the Trimble County area of the system are swinging together with very similar and overlapping periods. This property lowers the relative angular difference between the generators, results in a more stable system, and is another indication of a strong electric system without stability limitations.

Liberty concluded that the electric transmission system in the Trimble County area was very strong. A number of factors contributed to this including the mitigating effect at times of light load levels when peaking and intermediate generation is not on line to contribute to those swings, the stability margin provided by the excessive fault time used in the study, and the system response exhibited by a short system period where all generation was swinging together. Liberty notes that power systems that exhibit strong damping characteristics do not require modeling of relays because relay operation would only take place for severe swings in the system. Liberty also notes that the modeling of faults with delayed clearing on the 345 kV system eliminates the need for running lesser faults, such as faults on the 138 kV system, or those involving reclosing because delayed clearing of faults simulation generally represents worst case conditions.

MISO simulated all faults with a duration of 10 seconds. Long-term system dynamics can be a concern, and simulations are generally run out to 15 to 20 seconds or more to capture their effects. The short system period, the overlapping periods of generators in the Trimble County area, and the strong damping of system oscillations by the 10 second run end time, all indicate to Liberty that interaction of longer time constant generator feedback controls between the generators would not be a concern.[158]

MISO conducted most of its analyses in 2003 and modeled 2007 conditions because that was the anticipated commercial operation date of TC2. Since that time, the in service date of TC2 has been deferred to 2010 and Liberty questioned whether study results would remain valid for the new in service date. MISO stated that the loads modeled in their analyses for 2007 are now expected to occur in 2010, and new transmission facilities that were not included in their analyses for 2007 have not been or are not expected to be added until 2010.[159] In addition, MISO prepares its Transmission Expansion Plan every two years, and the conduct of this study captures ongoing system changes that were not known when it performed the TC2 studies.[160] Liberty concurs with the MISO reasoning, and is satisfied that MISO's study results will be valid for the 2010 in service date of TC2.

Liberty reviewed the size of the system models constructed by MISO, the level of system detail that was modeled, and the transmission voltage levels represented. In all studies, MISO represented the 69 kV transmission system of LG&E/KU. Within the ECAR area, all transmission branches and nodes at the 115 kV/138 kV level and above were represented for all

[157] Response to Liberty Data Request #10, Appendices to G218 Report provided as Exhibit MSJ-2.
[158] Response to Liberty Data Request #10, Appendices to G218 Report provided as Exhibit MSJ-2.
[159] Interview of May 17, 2005.
[160] Interview of May 17, 2005.

study models. For the power flow and stability models, all transmission branches and nodes at the 115 kV/138 kV level and above were represented for systems surrounding the ECAR area. MISO used the PTI PSS/E software package of power analysis programs to perform all of their analyses. The PTI PSS/E software programs are considered as state of the art industry wide.

Power flow studies showed that the same facilities overloaded in the 100 percent LG&E/KU ownership case were also overloaded in the 75 percent LG&E/KU ownership case.[161] No voltage violations were noted in either the 100 percent or 75 percent ownership cases. Power flow studies for the Indiana utilities that own the remaining 25 percent of TC2 were studied separately, and no Kentucky facilities were found to be overloaded, and no voltage violations of the LG&E/KU reliability standards were found to exist.[162] For the short circuit, cascading analysis, prior outage, and stability analyses, results are indifferent to the level of LG&E/KU ownership in TC2, as the unit is represented to be running at full output regardless of ownership.

The Companies instructed MISO to use the LG&E/KU reliability standards when conducting its analyses for the integration of TC2 into the transmission system. LG&E/KU has established reliability standards that prescribe which contingencies must be withstood without loss of load and which contingencies must be withstood with controlled loss of load. These reliability criteria also establish normal and emergency voltage limits, and equipment thermal limits that must be maintained under the various system conditions postulated. MISO conformed to the instructions and used LG&E/KU's voltage limits in their analyses as applicable. MISO ran single contingency analyses on all generators, transmission circuits, and transformers within the MISO and surrounding control areas. MISO used worst case conditions, such as the 17 cycle delayed cleared fault, in its stability analysis. MISO also included the multiple overlapping contingencies contained in the ECAR contingency list in its analyses.[163] Liberty's review confirmed that the MISO approach would directly or indirectly include the various components required by the LG&E/KU reliability standards.

G. Summary

With regard to reliability criteria, Liberty concluded that LG&E/KU used appropriate generation bias in its analysis to produce conservative results. Liberty found that the thermal and transient stability contingency performance requirements were consistent with, or stricter than, those required by ECAR, and that by the use of transmission emergency circuit ratings that can be continuously applied, the potential for cascading outages is virtually eliminated. Liberty also found that LG&E/KU's voltage limits are reasonable, inclusive of system requirements, and consistent with ECAR requirements. Liberty concluded that the LG&E/KU reliability standards are reasonable and that their application represents good utility practice.

Concerning thermal ratings, Liberty found that the LG&E/KU transmission equipment thermal rating methods include all system elements, have sufficient coordination, and are appropriately conservative. However, Liberty does suggest that in the future, to be in conformance with the NESC, inspections or calculations be performed on a line specific basis when that line is to be operated above its original design temperature.

[161] Response to Liberty Data Request #19.
[162] Interview of May 17, 2005.
[163] Response to Liberty Data Request #18.

Liberty found that the fault durations and equipment times for the faults simulated in the MISO transient stability studies were reasonable, conservative, and similar to times used in the industry.

Liberty found that LG&E/KU's load forecasting methods, econometric inputs, adjustments, and inclusion of demand-side contributions are reasonable and adequate for company-wide transmission reinforcement studies and that reasonable study results would be produced.

Liberty reviewed MISO's study results and conclusions and found them to be reasonable. The types of analyses and studies within each type of study that MISO performed were sufficient to produce reasonable study results. Liberty concluded that the analyses performed by MISO for the 2007 time frame would be representative and valid for 2010, the new in service date for TC2.

Liberty found that software used by MISO in its analyses was reasonable and of the quality used by utilities throughout the country. The models MISO constructed for the various analyses were reasonable, of sufficient size, and of sufficient detail to produce valid study results.

Liberty concluded that the facilities required to integrate the new TC2 unit into the LG&E/KU transmission system are required for both the 75 percent and 100 percent LG&E/KU ownership levels of TC2. Liberty concluded that MISO appropriately used the LG&E/KU reliability standards, either directly or indirectly, in the performance of its various analyses and that it conducted proper simulations.

III. Alternatives

This chapter presents the results of Liberty's review of the alternatives the Companies considered and the associated analyses that support LG&E/KU's need for the proposed transmission line. The chapter addresses:

- The upgrade of existing lines or facilities and transmission routes
- Other alternatives, including the use of generation and power factor improvement
- Whether wheeling power through neighboring systems or through interconnections with neighboring systems would be a viable alternative to construction of the proposed new transmission line.

A. Upgrades

1. Definition

Liberty evaluated whether LG&E/KU gave adequate consideration to upgrades of existing transmission lines for both LG&E/KU and neighboring utilities and the use of alternative transmission line routes. Liberty included a review of the cost analysis of the alternatives presented by LG&E/KU and a review of the application of new technology or automation to the solution.

2. Discussion

LG&E/KU initially identified the major components of five options that had the potential to integrate successfully the new TC2 unit into the network by conducting a preliminary screening analysis. The options included the upgrade of existing facilities as well as the addition of new facilities. The Companies accomplished the identification of possible options by performing a screening analysis. The table below shows the options identified by LG&E/KU and the major facilities required for each option.[1]

[1] Response to Liberty Data Request #10, Internal TC2 System Impact Study.

Table III.1
Options Identified by LG&E/KU to Integrate TC2 into the Transmission System
Major Facilities Required by Screening Study

LG&E/KU Option	Description	Cost* (millions)
Option #1	2.8 miles Double Circuit 345 kV from Trimble County to Ghent – Speed Tap 30.4 miles 345 kV from West Frankfort to Brown	$39.5
Option #2	2.8 miles Double Circuit 345 kV from Trimble County to Ghent – Speed Tap 42.9 miles 345 kV from Mill Creek to Hardin County	$56.6
Option #3	37.3 miles 345 kV from Trimble County to West Frankfort 30.4 miles 345 kV from West Frankfort to Brown	$74.1
Option #4	30.4 miles 345 kV from West Frankfort to Brown 42.9 miles 345 kV from Mill Creek to Hardin County	$80.8
Option #5	37.3 miles 345 kV from Trimble County to West Frankfort 30.4 miles 345 kV from West Frankfort to Brown 42.9 miles 345 kV from Mill Creek to Hardin County	$122.8

* Net of loss savings

After LG&E/KU's initial economic evaluations, MISO conducted additional evaluations, and renumbered these options. Therefore, option numbers referred to by LG&E, MISO, and in this report are those designated by MISO. The relationship between the LG&E numbering and those of MISO is shown in the following table.

Table III.2
Correlation of LG&E/KU and MISO Option Designations

LG&E/KU Option #	MISO Option #
1	3
2	4
3	1
4	2
5	Dropped

MISO and the ad hoc working group, consisting of subject matter experts from both LG&E/KU and surrounding utilities, studied the LG&E/KU proposed options and did not develop any other options. LG&E/KU's option #5 was eliminated due to cost considerations. All four remaining options solved the engineering problem of integrating TC2 in to the transmission system. LG&E/KU's option #2 (later designated as MISO Option Number 4 in LG&E/KU's final economic evaluation) was ultimately selected by LG&E/KU after MISO performed its thermal and stability delivery and facility analyses, and after LG&E/KU performed an economic analysis with all system requirements identified by MISO included. That analysis appears as Table III.3 below.

Table III.3
LG&E/KU Final Economic Evaluation[2]

Liberty's Facility Identification	Facility Required	MISO Option #1	MISO Option #2	MISO Option #3	MISO Option #4
A	Construct 37.3 miles 345 kV from Trimble county to West Frankfort	X			
B	Construct 30.4 miles 345 kV from West Frankfort to Brown	X	X	X	
C	Install Second 450 MVA 345/138 kV Transformer at Brown	X	X	X	
D	Construct 11.8 miles 138 kV from West Lexington to Higby Mill	X	X	X	X
E	Construct 10.2 miles 138 kV from West Frankfort to Tyrone	X			X
F	Install 2 - 345 kV Breakers at Trimble County	X	X	X	X
G	Construct 42.9 miles 345 kV from Mill Creek to Hardin County		X		X
H	Reconductor 1.3 miles 138 kV from Hardin County to Elizabethtown		X		X
I	Construct 2.8 miles Double Circuit 345 kV from Trimble County to the Ghent to Speed Tap			X	X
J	Reconductor 12.5 miles 138 kV from Ghent to Owen County Tap			X	X
K	Construct 3.1 miles 138 from Ghent to NAS			X	
	2007 NPV - \$ x 10^6 Net of Losses	**\$83.6**	**\$89.3**	**\$52.1**	**\$59.1**

To understand better the four MISO options, Liberty first broke them into two groups—a high cost group consisting of Options #1 and #2, and a lower cost group consisting of Options #3 and #4. In the first group, both options include two long 345 kV lines and other on-system (LG&E/KU) solutions to integrate TC2 into the transmission system. The second group, Options #3 and #4, includes a combination of off-system (the short Ghent to Speed 345 kV Double-Circuit tap to Indiana) and only one long 345 kV line, and other on-system solutions to integrate TC2 into the transmission system. Options #3 and #4 are more economical because the short double-circuit 345 kV tap to Indiana negates the need for a second, much longer and more expensive, 345 kV transmission line in Kentucky. Clearly, the higher costs associated with Options #1 and #2 in the first group eliminated them from additional consideration. MISO Option #4 was ultimately selected for economic reasons, as discussed below.

[2] Response to Liberty Data Request #11.

LG&E/KU performed additional economic analysis of Options #3 and #4. One of the distinguishing differences between these two options is that only Option #4 includes the long 345 kV line from Mill Creek to Hardin County. LG&E/KU's system studies indicated that because of upcoming voltage problems, Hardin County would need an additional Mill Creek to Hardin County 345 kV source within 5 to 8 years after TC2 began commercial operation in 2007, regardless of the reinforcements needed to integrate TC2 into the system.[3] This line was included in Option #4 (as Liberty Facility #G), but not included in MISO Option #3. At some point in the future, this 345 kV line from Mill Creek to Hardin County (Liberty Facility #G) will be needed. Based on installed costs, it might seem that Option #3 is more economical at the present time. However, the longer-term cost of adding the long 345 kV line from Mill Creek to Hardin County should be considered in order to more properly evaluate the differences between Options #3 and #4. Thus, if LG&E/KU were to choose to add this line later, approximately 10 years after TC2 was in operation, the net present value cost for MISO Option #3 of completing construction of the Mill Creek to Hardin County 345 kV line would be approximately $20 million more than MISO Option #4.[4] Liberty estimates that the Mill Creek to Hardin County 345 kV line would have to be deferred by approximately 20 years in order for Option #3 to be more economical than Option #4. System requirements, specifically voltage problems in Hardin County, would not make such a delay in construction of this line acceptable.

MISO Option #4 contains seven elements that Liberty identified as facility items D through J. The following Table III.4 describes how each of these elements has been handled by LG&E/KU in terms of integrating them into the formal siting approval process for construction of the facilities.

Table III.4
Categorization of Elements of MISO Option #4

Liberty's Facility Identification	Discussion
D	The West Lexington to Higby Mill 138 kV line is being constructed on an existing double circuit line that only has one circuit on it. LG&E/KU states that a siting certificate is not required to construct this facility.[5]
E	Case No. 2005-0154
F	LG&E/KU states that a siting certificate is not required for installation of two new breakers at Trimble County.[6]
G	Case No. 2005-0142
H	LG&E/KU states that reconductoring of 1.3 miles of 138kV line from Hardin County to Elizabethtown does not require a siting certificate.[7]
I	Case No. 2005-0155
J	LG&E/KU states that reconductoring of 12.5 miles of 138 kV line from Ghent to Owen County Tap does not require a siting certificate.[8]

[3] Response to Liberty Data Request #11.
[4] Response to Liberty Data Request #11.
[5] Interview of May 12, 2005.
[6] Interview of May 12, 2005.
[7] Interview of May 12, 2005.
[8] Interview of May 12, 2005.

3. Analysis

Installing a 750 MW generator and transmitting its output over long distances to load centers requires high voltage transmission facilities. LG&E/KU, using MISO and other experts as identified above, verified that even after upgrading the present LG&E/KU transmission system facilities, the system would not be sufficiently robust to meet applicable reliability standards after connecting TC2 to the system. New high voltage facilities would be needed. LG&E/KU thoroughly evaluated all reasonable solutions, all of which included some upgrades of the present facilities. LG&E/KU considered that the Mill Creek to Hardin County 345 kV line was needed whether or not TC2 was installed. It determined that the optimum solution was MISO Option #4 as this option negated the need for a second long 345 kV line to be built.

Liberty did not identify any additional facilities that could be upgraded in capacity that would have eliminated the need for the new facilities. Also, Liberty did not identify any additional options for resolving system loading problems resulting from the connection of TC2 to the system.

Liberty did not identify additional existing facilities that could be upgraded in voltage that would eliminate the need for the new facilities. If existing facilities were to be upgraded from a voltage standpoint, the system would lose the support of those facilities under contingency conditions. Loss of contingency support from those upgraded facilities might also require additional facilities beyond those for which LG&E/KU is currently requesting construction approval.

In 2005, LG&E/KU reduced the overall level of its integrated medium and long-term energy forecasts, which it prepared in 2002, by about 3 percent because of the effects of national economic weakness occurring 2001. However, the average annual increase of combined load growth from 2005 to 2019 continues to be about 2.0 percent, as forecasted in 2002. This allowed the in-service date of TC2 to be deferred from 2007 to 2010.[9] In the same manner, the need for the Mill Creek to Hardin County 345 kV line was originally forecasted to be within 5 to 8 years after TC2 was in-service in 2007, or between 2012 and 2015. While the line is needed to support future load in the Hardin County area, its need would also be delayed by the same amount of time as the delay for in-service of TC2, or by approximately three years. Thus, under MISO Option #3 the new Mill Creek to Hardin County 345 kV line would still be needed 5 to 8 years after the installation of TC2 in 2010.

Liberty agrees that the Mill Creek to Hardin County 345 kV line is needed to provide for future load growth and voltage support in the Elizabethtown area, where no local base load generation is present or planned. In addition, under MISO Option #4, the line is needed for system loads related to the connection of TC2 to the transmission system. Therefore, considering the deferred in-service date of TC2,[10] MISO Option #4, which includes the construction of the Mill Creek to Hardin County 345 kV line, remains more economical than MISO Option #3. On a present value basis, considering long-term project costs, MISO Option #4 is approximately $20 million less expensive than MISO Option #3.

[9] 2005 IRP, Case No. 2005-00162, Vol. I, pages 6-3 and 6-4.
[10] Response to Liberty Data Request #11.

Liberty found that no additional upgrades, other than those already identified by LG&E/KU, could replace the need for the new facilities.

Liberty found that the economic analysis performed by LG&E/KU was comprehensive, adequate, and reasonable and that the relative economic relationship of the alternatives remains intact even with the delay of the TC2 in service date to 2010.

B. Addition of Generation and Power Factor Improvement

1. Definition

Liberty evaluated whether LG&E/KU gave adequate consideration to the installation of local generation and power factor improvement as viable alternatives.

2. Discussion

In addition to on-system upgrades or interconnections with neighboring systems, there are other alternatives that may solve reliability problems. In cases where a utility encounters thermal restrictions, it can consider the addition of local generation. When a utility experiences voltage constraints, it may employ the addition of capacitors or other new technology reactive devices.

The thermal and stability studies conducted were performed and guided by ad hoc working groups that consisted of transmission system experts from LG&E/KU, MISO, and its surrounding systems.[11] The ad hoc working groups identified no other alternatives other than the four screening options supplied to them by LG&E/KU.[12] In performing their delivery and facilities studies for thermal conditions, MISO stated that all studies were monitored for thermal violations and violations of the LG&E/KU voltage criteria. All system violations noted in the studies were due to thermal overloads and no voltage violations were observed, implying the need for additional generation.[13]

Series capacitors were not considered in the analyses. Series capacitors can provide system benefits when voltage drop is a consideration or power flows over two paths are such that the transmission system is not efficiently used. The MISO studies showed that thermal overloads occurred on both the eastern and western portions of the system that required additional facilities to be constructed.[14]

MISO did not consider the addition of local generation. Local generation, when considered as a solution, is usually targeted to unload a specific line that needs reinforcement due to load growth in the local area. Local generation can therefore eliminate the need for the new facility. However, in the current case, the installation of a 750 MW base load unit is for total system resource adequacy reasons, not reinforcement due to localized load growth. Generation installed for resource adequacy is usually installed at large centralized generating stations such as Trimble

[11] Interview of May 17, 2005.
[12] Interview of May 17, 2005.
[13] Interview of May 18, 2005.
[14] Response to Liberty Data Request #19.

County. Trimble County was originally designed for expansion when first constructed by LG&E/KU a number of years ago. In addition, the amount of local generation that would have to be installed in order to resolve resource adequacy is so large that total system generation mix economics would be negatively impacted.

3. Analysis

Voltage considerations played no part in integrating TC2 into the transmission grid. The application of shunt capacitors or new technology reactive support devises would not be effective in reducing power flows on thermally overloaded facilities.

Voltage drops or unevenly loaded facilities were not a concern in integrating TC2 into the transmission system. The application of series capacitors would not be effective in efficiently redistributing power flows on the system as overloads occurred on both the eastern and western portions of the system, which required additional facilities to be constructed.

Liberty found that the installation of local generation, series or shunt capacitors, or other new technology reactive devices were not viable alternatives for the facilities requesting siting approval.

C. Wheeling

1. Definition

Liberty reviewed whether LG&E/KU gave adequate consideration to wheeling power from/through adjoining systems via existing or new interconnections with other systems.

2. Discussion

The LG&E/KU power system has two major load centers. These load centers are described in detail in Section II.B.3 above. On the LG&E/KU system, 345 kV transmission lines currently exist from Trimble County to Mill Creek, from Ghent to Brown, and from Brown to Hardin County. In addition, Ghent is connected to the Speed substation in Indiana by a 345 kV interconnection. These facilities essentially represent the total 345 kV system in this area of Kentucky. By constructing the new Mill Creek to Hardin County 345 kV line and tapping the Ghent to Speed 345 kV interconnection at Trimble County, LG&E/KU created a looped 345 kV system in this area of the system. The 345 kV loop ties the major generating stations at Ghent, Brown, Trimble County, and Mill Creek together such that generation from all these sources have high voltage paths to other areas of the system when needed. Such high voltage paths allow a significant amount of power to be moved between facilities when compared to lower voltage 138 kV or 161 kV paths.

3. Analysis

The four options studied by MISO considered interconnections and wheeling through a combination of on-system additions and off-system solutions to integrate TC2 into the transmission system. The option that was finally selected, MISO Option #4, incorporated a combination of both on-system and off-system additions to integrate the new unit into the transmission system. This option was optimum from both a technical and economic standpoint.

Liberty found that the only viable interconnection or wheeling opportunity for the integration of TC2 into the transmission system was included in MISO Option #4. This was the tapping of the Ghent to Speed 345 kV line. Thus, LG&E/KU's selection of this option was appropriate.

D. Summary

Liberty concurred with LG&E/KU that the preferred alternative of constructing a new 138 kV line from West Frankfort to Tyrone is necessary to accommodate the integration of TC2 into the transmission system. Liberty did not identify other upgrades of the existing system that appear capable of providing the required system relief.

Liberty found that the economic analysis performed by LG&E/KU was comprehensive, adequate, and reasonable and that the relative economic relationship of the alternatives remains intact with the delay of the TC2 in service date to 2010.

Liberty found that the installation of local generation, series or shunt capacitors, or other new technology reactive devices for power factor improvement were not viable alternatives to the facilities requesting siting approval.

Liberty found that the only viable interconnection or wheeling opportunity for the integration of TC2 into the transmission system was included in MISO Option #4. This was the tapping of the Ghent to Speed 345 kV line. Thus, LG&E/KU's selection of this option was appropriate.