Barrington-Wellesley Group, Inc.
Management Consultants

2479 Lanam Ridge Road • Nashville, IN 47448 • Tel: (812) 988-0190 • Fax (812) 988-0194

July 21, 2005

RECEIVED
JUL 21 2005
PUBLIC SERVICE COMMISSION

Mr. John A. Rogness III
Staff Project Officer, Management Audit Branch
Kentucky Public Service Commission
P.O. Box 615
211 Sower Boulevard
Frankfort, Kentucky 40602

RE: KPSC Case # 2005-00101 / Transmission CPC&N – Final Report

Dear Mr. Rogness,

Enclosed please find fifteen bound copies, one unbound, and one electronic copy of BWG/Auriga's final report on the focused audit of Kentucky Power's application for a new transmission line in eastern Kentucky.

We appreciate the opportunity to have worked with you and your colleagues at the KPSC on this engagement. Please do not hesitate to call if you have any questions or comments regarding our report or any other issues.

Sincerely,

Michael A. Laros

Michael A. Laros
Co-President

Need Assessment of 161 kV Transmission Interconnection

Application Filed by Kentucky Power Company Before the Kentucky Public Service Commission Case No. 2005-00101

July 22, 2005

BWG

Barrington–Wellesley Group, Inc.
Auriga Corporation

Auriga corporation

TABLE OF CONTENTS

List of Figures

List of Tables

EXECUTIVE SUMMARY

BACKGROUND

On June 17, 2005, Kentucky Power Company (Kentucky Power, a wholly-owned subsidiary of American Electric Power Company (AEP)) filed an application to Kentucky Public Service Commission (KPSC) for a Certificate of Public Convenience and Necessity to construct a 161 kV transmission line in Leslie County, Kentucky.[1] Kentucky Power anticipates that the proposed 5,751 foot 161 kV line would meet the adequacy and reliability requirements of the Hazard Area by interconnecting Kentucky Power's Pineville – Hazard 161 kV line and Louisville Gas & Electric (LG&E)'s Delvinta – Arnold 161 kV line.[2]

Barrington-Wellesley Group, Inc. (BWG) was contracted by the KPSC to conduct a focused review of Kentucky Power's analysis supporting its application for a certificate to construct this transmission line (Need Review). BWG and its technical subcontractor, Auriga Corporation (Auriga), first conducted a general technical assessment in areas important to transmission expansion planning such as load forecast, reliability criteria, and contingency selection. BWG/Auriga then assessed potential solutions considered by Kentucky Power and developed conclusions regarding Kentucky Power's support for the need for the proposed Hazard area interconnection solution. As this was a focused review, BWG/Auriga did not perform independent system studies but rather, based its assessment on information provided by Kentucky Power in response to formal data requests and through presentations made by AEP transmission planning personnel at AEP's Gahanna, Ohio office.

This report presents BWG/Auriga's findings and conclusions on the assessment of the need for a Certificate of Public Convenience and Necessity to construct a 161 kV transmission line in Leslie County, Kentucky.

OBJECTIVE, SCOPE, AND APPROACH

The objective of this project was to review and assess the need for constructing a 161 kV transmission line in Leslie County, Kentucky. The scope of work included an independent review and evaluation of Kentucky Power's application for constructing a 161 kV transmission line based on Kentucky Power's filing document and other supporting materials provided to BWG/Auriga as well as best industry practices in transmission system planning. BWG/Auriga did not perform independent transmission system studies such as load flow, stability, and short-circuit analysis.

[1] June 17, 2005 Kentucky Power's Application (Kentucky Power's response to BWG data request BWG-1).
[2] June 17, 2005 Kentucky Power's Application (Kentucky Power's response to BWG data request BWG-1), Section 12.

BWG/Auriga took the following approach in this project. First, the system was characterized and the problems were identified. Then, a general assessment was made on Kentucky Power's approach and basic assumptions to address various issues that affect the identified problems. Finally, a detailed assessment was performed on Kentucky Power's proposed solution and other alternatives.

PROJECT OVERVIEW

Kentucky Power, based in Frankfort, Kentucky, is an electric utility organized as a corporation under the laws of the Commonwealth of Kentucky in 1919. Kentucky Power is engaged in the generation, purchase, transmission, distribution, and sale of electric power. Kentucky Power serves approximately 175,000 customers in the following 20 counties of eastern Kentucky: Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Johnson, Knott, Lawrence, Leslie, Letcher, Lewis, Magoffin, Martin, Morgan, Owsley, Perry, Pike, and Rowan. Kentucky Power also supplies electric power at wholesale to other utilities and municipalities in Kentucky for resale.[3]

Kentucky Power is a wholly-owned subsidiary of AEP. AEP is a multi-state public utility holding company that provides electric power service to customers in parts of the following eleven states: Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia.[4]

Kentucky Power filed an application on June 17, 2005 with KPSC for constructing a 5,751 foot 161 kV transmission line and the Wooten Station in eastern Leslie County, Kentucky. The line will connect Kentucky Power's Pineville – Hazard 161 kV line and LG&E's Delvinta – Arnold 161 kV line.[5] The proposed interconnection is intended to increase service reliability in the Hazard Area. The total cost for the proposed line and new switching station is about $4.2 million.[6]

Based on the filing document, materials provided by AEP, and face-to-face interview meeting with AEP transmission planning personnel at Gahanna, OH on July 8, 2005, BWG/Auriga performed a general assessment on the following aspects in addressing the identified problems: basic assumptions, system planning approach, reliability criteria, load forecast, generation dispatch scenarios, reactive power needs, contingency selection, load flow and stability studies, short-circuit analysis, and system protection studies. Based on this general assessment, BWG/Auriga conducted a detailed assessment on Kentucky Power's proposed

---

[3] June 17, 2005 Kentucky Power's Application (Kentucky Power's response to BWG data request BWG-1), Section 1.
[4] June 17, 2005 Kentucky Power's Application (Kentucky Power's response to BWG data request BWG-1), Section 2.
[5] June 17, 2005 Kentucky Power's Application (Kentucky Power's response to BWG data request BWG-1), Section 3.
[6] June 17, 2005 Kentucky Power's Application (Kentucky Power's response to BWG data request BWG-1), Section 4.

solution, a 161 kV interconnection at Wooten, and an alternative, a 138 kV interconnection between the Harbert and Hazard Stations. Finally, BWG/Auriga provided a summary and conclusions regarding Kentucky Power's approach and the need for a new 161 kV transmission line.

CONCLUSIONS

Upon review of all the information regarding the Hazard Area transmission system reinforcement, BWG/Auriga reached the following conclusions:

- Kentucky Power needs to reinforce the Hazard Area transmission system to ensure adequate and reliable power supply to the area loads.
- The proposed Wooten Interconnection project is the most technically and economically viable solution to the Hazard Area problems.
- The Harbert – Hazard 138 kV line alternative, which may meet the needs technically, is not a cost-effective solution.

1 INTRODUCTION

1.1 BACKGROUND

On June 17, 2005, Kentucky Power Company (Kentucky Power, a wholly-owned subsidiary of American Electric Power Company (AEP)) filed an application to Kentucky Public Service Commission (KPSC) for a Certificate of Public Convenience and Necessity to construct a 161 kV transmission line in Leslie County, Kentucky.[7] Kentucky Power anticipates that the proposed 5,751 foot 161 kV line would meet the adequacy and reliability requirements of the Hazard Area by interconnecting Kentucky Power's Pineville – Hazard 161 kV line and Louisville Gas & Electric (LG&E)'s Delvinta – Arnold 161 kV line.[8]

Barrington-Wellesley Group, Inc. (BWG) was contracted by the KPSC to conduct a focused review of Kentucky Power's analysis supporting its application for a certificate to construct this transmission line (Need Review). BWG and its technical subcontractor, Auriga Corporation (Auriga) first conducted a general technical assessment in areas important to transmission expansion planning such as load forecast, reliability criteria, and contingency selection. BWG/Auriga then assessed potential solutions considered by Kentucky Power and developed conclusions regarding Kentucky Power's support for the need for the proposed Hazard area interconnection solution. As this was a focused review, BWG/Auriga did not perform independent system studies but rather, based its assessment on information provided by Kentucky Power in response to formal data requests and through presentations made by AEP transmission planning personnel at AEP's Gahanna, Ohio office.

1.2 OBJECTIVE, SCOPE, AND APPROACH

The objective of this project was to review and assess the need for constructing a 161 kV transmission line in Leslie County, Kentucky. The scope of work included an independent review and evaluation of Kentucky Power's application for constructing a 161 kV transmission line based on Kentucky Power's filing document and other supporting materials provided to BWG/Auriga as well as best industry practices in transmission system planning. BWG/Auriga did not perform independent transmission system studies such as load flow, stability, and short-circuit analysis.

BWG/Auriga took the following approach in this project. First, the system was characterized and the problems were identified. Then, a general assessment was made on Kentucky Power's approach and basic assumptions to address various issues that affect the identified

[7] June 17, 2005 Kentucky Power's Application (Kentucky Power's response to BWG data request BWG-1).
[8] June 17, 2005 Kentucky Power's Application (Kentucky Power's response to BWG data request BWG-1), Section 12.

problems. Finally, a detailed assessment was performed on Kentucky Power's proposed solution and other alternatives.

1.3 System Overview

Kentucky Power is part of the AEP Company, a holding company which serves more than 5 million customers across eleven (11) states. AEP is the nation's largest electricity generator, with more than 36,000 megawatts of generating capacity in the United States. The company is based in Columbus, Ohio.[9]

Kentucky Power provides electric power service to approximately 175,000 customers in all or part of twenty (20) eastern Kentucky counties. Its headquarters is located in Frankfort, Kentucky.[10]

In addition to its AEP system interconnections, Kentucky Power is also interconnected with the following unaffiliated utility companies: Kentucky Utilities Company (KU), East Kentucky Power Cooperative (EKPC), and Tennessee Valley Authority (TVA).

The Hazard Area is one of four load areas within the Kentucky Power service territory. It is located in the eastern portion of the Commonwealth and includes the Cities of Hazard, Hindman, Hyden, Jenkins, and Whitesburg. The area load is about 350 MW and supplied by the following three transmission lines: The Beaver Creek – Hazard 138 kV line, the Pineville – Hazard 161 kV line, and the Fleming – Collier 69 kV line. These three lines are the only links that normally connect the Hazard Area to the remainder of the transmission system. The Beaver Creek Station at one end of the Beaver Creek – Hazard 138 kV line connects the Hazard Area to the remainder of the AEP transmission system via several 138 kV transmission lines. The Pineville Station at one end of the Pineville – Hazard 161 kV line is a 161 kV interconnection point with the TVA system. The Hazard Station connects the 138 kV and the 161 kV networks via three single phase 45 MVA, 161/138 kV transformers and also serves the local area subtransmission loads. The Beaver Creek Station is located about 28 miles northeast of the Hazard Station.[11] It is a major switching station in the area. The ± 125 MVAr Static VAR Compensator and four (4) 138 kV shunt capacitors at the Beaver Creek Station, together with capacitor banks at several other stations, provide reactive power and voltage support to the area. The Pineville Station is located about 45 miles southwest of the Hazard Station.[12].

---

[9] Kentucky Power's web site.
[10] June 17, 2005 Kentucky Power's Application (Kentucky Power's response to BWG data request BWG-1), Section 1.
[11] June 17, 2005 Kentucky Power's Application (Kentucky Power's response to BWG data request BWG-1), Sections 8 & 9.
[12] July 8, 2005 Interview with AEP transmission planning personnel.

Figure 1-1 shows the Hazard Area transmission system.[13] The area of interest is highlighted with a circle.

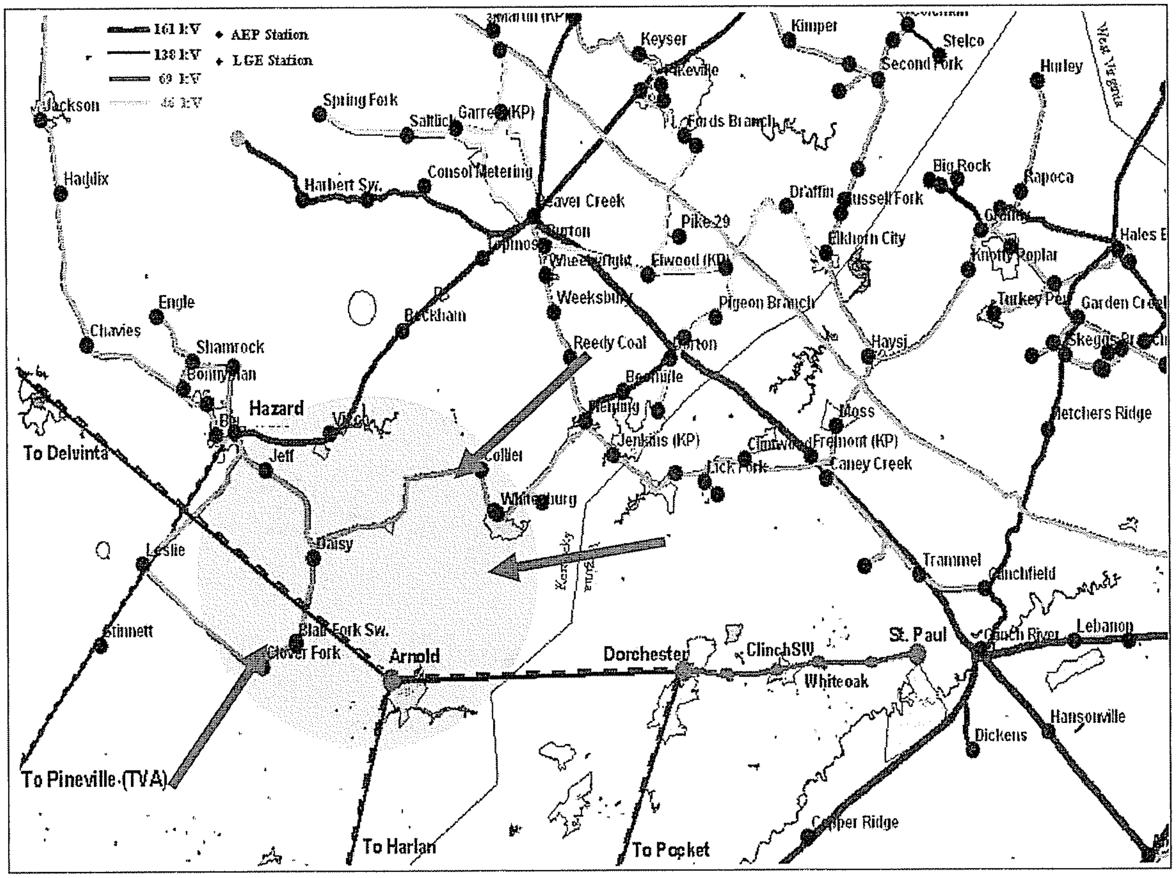


Figure 1-1 Transmission System in the Hazard Area

[13] AEP – LG&E Interconnections Roanoke Transmission Region – Kentucky & Virginia, East Area Transmission Planning, October 2004 (Kentucky Power's response to BWG data request BWG-8).

1.4 Problem Identified

The load in the Kentucky Power system varies throughout the year with its peaks in the summer and winter. The winter peak load is typically higher than the summer peak load as seen in the historical and forecasted load from 1994 to 2015. This winter peak loading level results in the most stressed operating conditions in the system. Therefore, the 2004 winter peak case was used by AEP as a base case for power flow and contingency studies. The power flow simulation results indicated that single contingencies would result in thermal overloads on several facilities and low voltages in the Hazard Area.[14]

There is no generation in the Hazard Area. With only three transmission lines importing power to the Hazard Area, it is expected that loss of any one transmission line (N-1 contingency) may cause thermal overloads on other facilities. The Beaver Creek – Hazard 138 kV line and the Pineville – Hazard 161 kV line each carries more MW flow than the Fleming – Collier 69 kV line. The critical contingencies are loss of one of these two lines. AEP transmission planning performed load flow studies for the 2004 and 2007 winter peak cases under normal system conditions as well as under two contingency conditions: Loss of the Beaver Creek – Hazard 138 kV line and loss of the Pineville – Hazard 161 kV line.[15]

Under normal system conditions, the line flows and bus voltages in the Hazard Area are within the acceptable ranges (line flows less than the normal ratings and bus voltages within ± 5% of nominal). However, with loss of either the Pineville – Hazard 161 kV line or the Beaver Creek – Hazard 138 kV line, the other line and/or the Fleming – Collier 69 kV line would be heavily overloaded (120% of normal ratings) and the area voltages would drop to unacceptable levels (lower than 92% of nominal). For example, loss of the Pineville – Hazard 161 kV tie with TVA would result in thermally overloading the Beaver Creek – Hazard 138 kV line up to 120% of its winter emergency rating (228 MVA). The same contingency would cause very severe voltage drops at most buses (lower than 60% of nominal, far below the acceptable limit of 92% of nominal). Such heavy overloading and very low voltage operating conditions would jeopardize the reliable service to over 350 MW of load in the Hazard Area. An outage of the Beaver Creek 138 kV area source would also result in thermal overload and depressed voltage conditions in the entire Hazard Area. Table 1-1 lists line loading levels under normal and contingency conditions for the 2004 Winter Peak Case. It can be seen that even under normal operating conditions, the MW loading on the Fleming – Collier 69 kV line is very high (93% of the normal rating).[16]

The load flow study results from AEP for the above contingencies during the summer peak load conditions produced similar thermal overload and voltage depression situations.[17]

---

[14] Load flow study results (Kentucky Power's response to BWG data request BWG-5).
[15] July 8, 2005 Interview with AEP transmission planning personnel.
[16] Load flow study results (Kentucky Power's response to BWG data request BWG-5).
[17] AEP – LG&E Interconnections Roanoke Transmission Region – Kentucky & Virginia, East Area Transmission Planning, October 2004 (Kentucky Power's response to BWG data request BWG-8).

Table 1-1 Transmission Line Flows under Normal and Contingency Conditions, Winter Peak – 2004

Transmission Line Segment	Normal Rating (MVA)	Emergency Rating (MVA)	Normal Conditions – All Elements in Service (% of Normal Rating)	Outage of Pineville – Hazard 161 kV Line (% of Emergency Rating)
Pineville – Hazard 161 kV Line	317	332	190 (60%)	0
Beaver Creek – Hazard 138 kV Line	203	228	122 (60%)	275 (120%)
Fleming – Collier 69 kV Line	76	96	71 (93%)	116 (121%)

1.5 ORGANIZATION OF THE REPORT

This report is organized as follows. Section 2 provides an overall assessment on AEP's technical approach to transmission expansion planning studies. Section 3 discusses potential solutions to the identified problems in the Hazard Area and assesses Kentucky Power proposed solution. Section 4 provides conclusions.

2 ASSESSMENT OF TECHNICAL APPROACH

2.1 OVERVIEW OF TRANSMISSION PLANNING APPROACH

2.1.1 Introduction

The traditional transmission expansion planning process focuses on assessing the impacts of transmission projects on system reliability. Now many transmission expansion planning studies also consider generation and demand side management alternatives in addition to transmission additions. The planning process involves a number of system studies for various scenarios spanning different time horizons typically from one year up to ten (10) years. The system studies require the following information:

- Bus level load forecast
- Generation forecast
- System loading conditions
- Power system static and dynamic models
- Contingencies

Normally, the transmission system is studied under expected peak load conditions to simulate stressed system operating conditions with generation operated in an economic fashion. System performance is then compared with the required reliability criteria such as those from North American Electric Reliability Council (NERC), regional reliability councils such as East Central Area Reliability Council (ECAR), independent system operators (ISO) such as Midwest ISO (MISO), and individual utilities such as AEP. Transmission plans are regarded as adequate if the system performances meet the reliability criteria under the specified contingency conditions.

2.1.2 AEP's Transmission Planning Approach

AEP's transmission planning process provides the focus for establishing an appropriate level of system reliability. AEP distinguishes the approach for the bulk transmission system (EHV facilities operating at 765 kV, 500 kV, 345 kV, and 230 kV as well as certain 138 kV facilities) from that for the area transmission system (HV facilities operating at 161 kV, 138 kV, 115 kV, and lower voltage subtransmission facilities) due to their different characteristics and functions of service. The AEP planning process encompasses a continuum of activities beginning with near term (operational planning) studies for system performance assessment to long term system studies for facility additions or strategic planning. Near term system studies have a horizon of up to one year. Long term system studies analyze anticipated system conditions over a time period from one up to ten (10) years.

In AEP's approach for long term planning of the area transmission system, the following modeling assumptions are used[18]:

- System active power (MW) loads are forecasted loads provided by AEP's Resource Planning and Operations Analysis function.
- Generators are normally dispatched to simulate economic operation to meet the load demand for system conditions being studied.
- System studies usually simulate system performance during peak load periods because this condition produces the most heavily loaded transmission conditions.
- Base cases model all transmission facilities in service except for known scheduled maintenance (normally for operational planning studies only), long term construction outages, or long-term forced outages. Neighboring company information is obtained from the latest regional or interregional study group models, the ECAR base cases, the NERC MMWG load flow library, or the neighboring company itself.
- Single contingencies (N-1) are used for the subtransmission system (23 kV to 88 kV) and single or double contingencies for the HV transmission system (138 kV and 161 kV).

For the area transmission system studies, AEP also applies probabilistic techniques to evaluate the need for transmission reinforcement projects. The goal of the probabilistic approach is to quantify the risk (via a project index) of disrupting service to an area due to contingencies. The risk index is defined by the product of the following three probabilities:

- Probability of an outage and its duration
- Probability of the actual load being high enough to cause transmission system problem
- Probability of overload and/or voltage drop will cause disruption of service

A project index is the product of a risk index and the corresponding affected load summed over all contingencies. A constant, which represents a threshold value for the project index in determining reinforcement need, is selected based on engineering judgment and then applied uniformly for all area transmission analyses. Based on these probabilistic concepts, AEP established its Project Priority Guide (PPG) for ranking the potential transmission reinforcement projects.[19]

The transmission system study for the Hazard Area was a long term planning study with a base year of 2004 (Winter Peak Load) and consideration of three years into the future for an area transmission system. AEP transmission planning engineers followed AEP's transmission planning criteria and process as highlighted above when conducting the Hazard Area system studies.[20]

---

[18] AEP's FERC Form 715 Filing, Part 4 – Transmission Planning Reliability Criteria Eastern AEP, March 2005 (Kentucky Power's response to BWG data request BWG-2).
[19] AEP's FERC Form 715 Filing, Part 4 – Transmission Planning Reliability Criteria Eastern AEP, March 2005 and Sub-Transmission Planning Criteria, AEP Presentation, June 3, 2005 (Kentucky Power's response to BWG data request BWG-2).
[20] July 8, 2005 Interview with AEP transmission planning personnel.

2.1.3 Discussion

AEP's overall transmission planning approach is similar to that used by other companies in the industry. Its application of probabilistic approach represents an industry needs and trends in transmission planning. The probabilistic approach provides additional insights into transmission investment problems and allows a quantitative way to balance reliability (risk) and cost. For example, AEP allows a greater risk if less load is affected. This is reflected in the computation of the project priority index. However, the probabilistic approach has extensive data requirements that may not be available in some cases. AEP's approach of starting with its application to the area transmission planning process provides a realistic way to achieve the practical results without encountering the difficulty in gathering a large amount of data at the bulk transmission system level. This is because more of the factors affecting area transmission planning, such as area loads, can be easily defined probabilistically. Bulk transmission planning, on the other hand, is impacted by more interconnected system variables. AEP's planning approach is consistent with Good Utility Practice[21] and with industry trends. It also follows the guidelines in the NERC[22] and ECAR[23] reliability criteria though these criteria are primarily for bulk transmission planning. BWG/Auriga concludes that AEP's study approach in the Hazard Area planning studies is appropriate and sufficient for evaluating the need for transmission reinforcement projects.

2.2 RELIABILITY CRITERIA

2.2.1 Introduction

Reliability criteria are used to measure transmission system performance under various operating conditions. The system performances are categorized into steady state performance and dynamic performance. The steady state performance is measured by thermal loading levels on system elements and bus voltage deviations from their nominal values. The dynamic performance is measured by whether any generator loses synchronism following an occurrence of a contingency such as a three phase fault on a transmission line. The system performance standards provide the basis for determining whether system response to the normal or contingency conditions is acceptable. The operating conditions under consideration typically include both normal and contingency conditions. A normal operating

[21] Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.
[22] NERC Reliability Standards, April 2005.
[23] ECAR Document No. 1, July 1998.

condition is a condition where all system elements are in service (sometimes called N-0). A contingency operating condition is where one (called N-1) or more (called N-k, where $k \geq 2$ is the number of simultaneously outaged elements) system elements are out of service.

2.2.2 AEP's transmission planning reliability criteria

AEP plans its 138 kV transmission and lower voltage subtransmission systems on normal (N-0) and single contingency (N-1) bases incorporating the likelihood of various scenarios and contingencies. More likely events require higher levels of system performance; lower system performance standards are acceptable for events that are less likely to happen. AEP performs transmission planning studies for peak load periods since this condition produces the most heavily loaded transmission situations.[24]

Table 2-1 shows AEP's reliability criteria for the steady state system performance.[25] AEP applies normal thermal ratings for all planning and operational studies for normal operating conditions. For N-1 contingency conditions, AEP uses winter emergency ratings for the 138 kV and above transmission facilities and normal ratings for the lower subtransmission system facilities.

Table 2-1 AEP's Transmission Planning Reliability Criteria

AEP Transmission Planning Reliability Criteria			
System Condition	Maximum Facility Loading (Rating)	Minimum Bus Voltage (p.u.)	
		EHV	138 kV and Lower
Normal (all elements in service)	Normal	0.95	0.95
Single contingency (one element out of service)	Emergency* Normal**	0.90	0.92

* 138 kV and 161 kV transmission system elements
** Lower than 138 kV subtransmission system elements

2.2.3 Discussion

NERC Reliability Criteria and ECAR Reliability Criteria are the North American continental and regional reliability criteria that are consistent with Good Utility Practice and should be followed by all ECAR members to the extent possible. As mentioned earlier, those criteria are primarily for bulk transmission planning. The reliability problems in the Hazard Area are essentially local problems that involve three transmission lines (the Pineville – Hazard 161 kV line, the Beaver Creek – Hazard 138 kV line, and the Fleming – Collier 69 kV line) and buses in the local area. With respect to following NERC and ECAR criteria and guidelines, the fundamental principle for the reliability criteria applicable to this area is that the

[24] Kentucky Power's response to BWG data request BWG-2.
[25] AEP's FERC Form 715 Filing, Part 4 – Transmission Planning Reliability Criteria Eastern AEP, March 2005 and Sub-Transmission Planning Criteria, AEP Presentation, June 3, 2005 (Kentucky Power's response to BWG data request BWG-2).

contingencies in this area will not jeopardize the power supply to the local area loads and will not have adverse impacts on the neighboring systems and the bulk transmission system. The AEP transmission planning reliability criteria (N-0 and N-1 criteria) as applied to the Hazard Area system are reasonable when compared with NERC and ECAR reliability criteria and with planning practices in other electric utilities in North America.

2.3 LOAD FORECAST

2.3.1 Introduction

Load forecast is a prerequisite for conducting proper long-term transmission expansion planning studies, since load level modeled in the studies can significantly impact the facility upgrades or additions that the system studies identify as necessary. Load forecast can be classified into short-term (normally hourly load forecast for one week up to one year) and long-term forecast (hourly, monthly, seasonal, or annual forecast for a period longer than one year). The short-term load forecast is used for operational planning studies. The long-term load forecast is used for transmission expansion planning that typically is more than one year and up to ten (10) years.

2.3.2 AEP's load forecasting approach[26]

The load forecasts for Kentucky Power and the other operating companies in the AEP system are based on a forecast of U.S. economic growth provided by Economy.com (formerly RFA). Inherent in the load forecasts are the impacts of past customer energy conservation and load management activities, including company-sponsored demand-side management (DSM) programs already implemented. The load impacts of future, or expanded, DSM programs are analyzed and projected separately, and appropriate adjustments applied to the load forecasts.

Kentucky Power's total internal energy requirements, before consideration of the effects of expanded DSM programs, are forecasted to increase at an average annual rate of 1.6% from 2005 to 2016. The corresponding summer and winter peak internal demands are forecasted to grow at an average annual rate of 1.7%. Kentucky Power's annual peak demand is expected to continue to occur in the winter season.

The goal of AEP's long-term forecasting models is to produce a reasonable load outlook for up to twenty (20) years in the future. Given that goal, the long-term forecasting models employ a full range of structural economic and demographic variables, electricity and natural gas prices, weather, as measured by annual heating and cooling degree-days, and binary variables to produce load forecasts conditioned on the outlook for the U.S. economy, for Kentucky Power's service-area economy, and for relative energy prices.

[26] 2002 Kentucky Power Integrated Resource Plan, Section 2 (Load Forecast) (Kentucky Power's response to BWG data request BWG-4).

Most of the explanatory variables enter the long-term forecasting models in a straightforward, untransformed manner. In the case of energy prices, however, it is assumed, consistent with economic theory, that the consumption of electricity responds to changes in the price of electricity or substitute fuels with a lag, rather than instantaneously. This lag occurs for reasons having to do with the technical feasibility of quickly changing the level of electricity use even after its relative price has changed, or with the widely accepted belief that consumers make their consumption decisions on the basis of expected prices, which may be perceived as functions of both past and current prices.

The estimation period for the long-term load forecasting models is 2005 - 2015. The long-term energy sales forecast is developed by applying the growth rates from the long-term models to the unbilled energy sales forecasts for 2005. The appropriate models for different variables are used in the long-term forecast. These include supplying models, residential energy sales, commercial energy sales, industrial energy sales, and other variables.

To forecast peak demand, AEP used algorithms similar to those in the HELM (Hourly Electric Load Model), originally developed by EPRI (Electric Power Research Institute). AEP used the methodology to forecast hourly load. Additional inputs in the analysis include weather data, load shapes, transmission and distribution losses, and calendar information. The output from the model includes hourly loads by operating company for the entire forecast period.

AEP used a model that calculates the hourly distribution of loads based on energy sales forecasts, load shapes, and WRFs (Weather Research and Forecast) for system load totals of the operating company. Loads are calculated on an hourly basis and calibrated for weather normalization purposes. The calculated hourly loads for each operating company are added together to form total regulated east AEP hourly load.

Specifically, the model calculates an hourly load shape for the operating company. The model calculates daily energy based on a WRF. WRFs are defined for all combinations of specified seasons, day types, and daily weather variables. The weather variable used by the model is average daily temperature. The average daily temperature is determined by averaging the daily high and daily low temperatures. The forecast of daily "typical" average temperatures was developed by selecting twelve representative historical months from the past 30-year period (1971 to 2000). These representative months were then combined to form the "typical" or "normal" year.

Different WRFs are defined according to the average temperature values recorded on any given day. WRFs are then applied to weather parameters to yield daily kWh for the operating company. Daily energies are then compared against total annual energy to determine the distribution of energy over the calendar year, resulting in daily energy percentages. These daily percentages are then applied to the annual kWh forecast to determine the daily distribution of forecast energy.

The final step is to allocate the daily energy to hours based on season and day type specific load shapes developed from historical load patterns. Planned demand-side management impacts (modeled independently), an hourly MW load profile, and system loss factors are then added to determine total MW load.

Table 2-2 shows the historical and forecasted peak demand for the period from 1994 to 2015[27]. Figure 2-1 plots the historic and forecasted energy requirements and winter peak demand from 1992 to 2016 at Kentucky Power.[28]

[27] Provided to BWG/Auriga during the July 8, 2005 Interview with AEP.
[28] 2002 Kentucky Power Integrated Resource Plan, Section 2 (Load Forecast) (Kentucky Power's response to BWG data request BWG-4).

Table 2-2 Historical and Forecasted Loads from 1994 to 2015

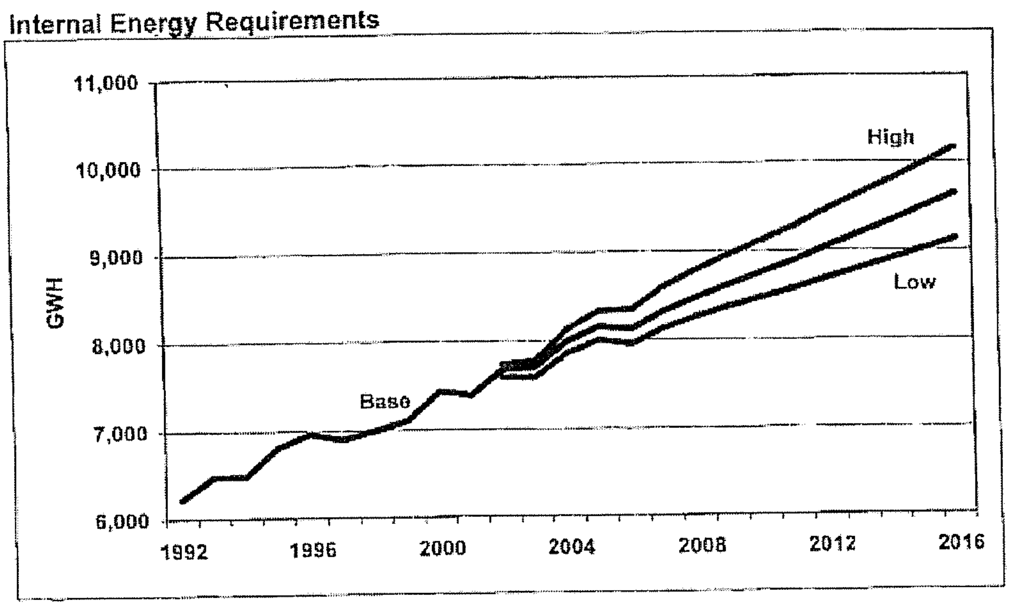
Kentucky Power Company
Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factoı
1994-2015

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
1994	06/20/94	1,079	---	01/19/94	1,309	---	1,309	---	6,483	---	56.5
1995	08/15/95	1,136	5.3	02/09/95	1,363	4.1	1,363	4.1	6,808	5.0	57.0
1996	08/07/96	1,087	-4.3	02/05/96	1,418	4.0	1,418	4.0	6,950	2.2	55.9
1997	07/28/97	1,164	7.1	01/17/97	1,417	-0.1	1,417	-0.1	6,897	-0.9	55.6
1998	08/25/98	1,213	4.2	03/13/98	1,299	-8.3	1,299	-8.3	6,992	1.4	61.4
1999	07/30/99	1,215	0.2	01/05/99	1,432	10.2	1,432	10.2	7,106	1.6	56.7
2000	08/09/00	1,210	-0.4	01/27/00	1,558	8.8	1,558	8.8	7,368	3.7	53.8
2001	08/07/01	1,302	7.6	01/03/01	1,579	1.3	1,579	1.3	7,433	0.9	53.7
2002	08/05/02	1,326	1.8	01/04/02	1,551	-1.8	1,551	-1.8	7,714	3.8	56.8
2003	08/26/03	1,212	-8.6	01/27/03	1,564	0.8	1,564	0.8	7,531	-2.4	55.0
2004		1,319	8.9	01/31/04	1,478	-5.5	1,512	-3.3	8,074	7.2	60.8
Forecast											
2005		1,364	3.4		1,687	14.2	1,687	11.6	8,241	2.1	55.8
2006		1,355	-0.6		1,695	0.5	1.695	0.5	8,249	0.1	55.5
2007		1,384	2.1		1,722	1.6	1,722	1.6	8,410	2.0	55.8
2008		1,398	1.1		1,741	1.1	1,741	1.1	8,522	1.3	55.9
2009		1,420	1.5		1,769	1.6	1,769	1.6	8,629	1.3	55.7
2010		1,437	1.2		1,791	1.2	1,791	1.2	8,738	1.3	55.7
2011		1,458	1.4		1,816	1.4	1,816	1.4	8,857	1.4	55.7
2012		1,473	1.1		1,834	1.0	1,834	1.0	8,979	1.4	55.9
2013		1,498	1.7		1,866	1.7	1,866	1.7	9,103	1.4	55.7
2014		1,519	1.4		1,892	1.4	1,892	1.4	9,229	1.4	55.7
2015		1,540	1.4		1,918	1.4	1,918	1.4	9,357	1.4	55.7

Note: 2004 data are six months actual and six months forecast.

Corporate Planning and Budgeting
2005 Load Forecast

Kentucky Power Company
Range of Forecasts



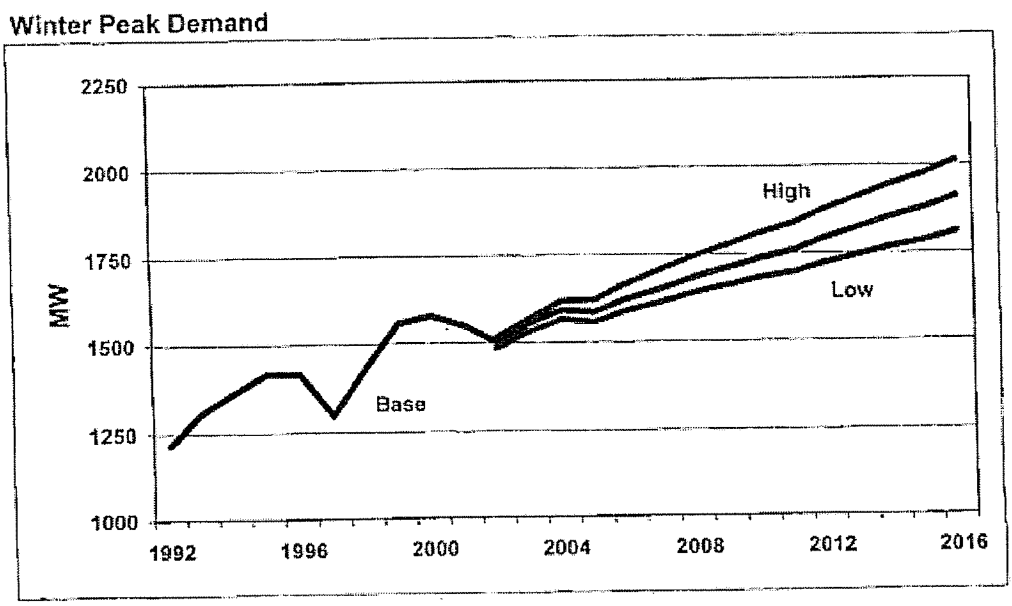


Figure 2-1 Energy Requirements and Winter Peak Demand at Kentucky Power

In addition to company-wide peak demand forecast, AEP also develops area load forecast reconciled with the company forecast for the following four areas: Ashland, Hazard, Pikeville, and Sprigg. For area load forecast, 1 in 5 years extreme weather forecast is used for high and low scenarios[29]. The software tool used for area load forecast is based on SAS, a common industry statistics and data analysis tool.[30]

2.3.3 Discussion

Studies done for the Hazard Area are for local load serving concerns and therefore have different load level modeling requirements from those studies for addressing regional transmission facility upgrades or additions such as the design of major interties. Generally, local area studies require more stringent load level modeling such as 1 in 10 years of extreme weather load rather than 1 in 5 years as in regional transmission expansion studies. There are two main reasons for this. One is that there are fewer resources or options to mitigate system performance concerns during operation in local areas than on the regional basis. The other is that there is more uncertainty in local area load forecast than in regional load forecast due to more diverse load compositions in a region. In addition, having a more stringent standard for local areas will help minimize the potential interruption of end-user customers. AEP used 1 in 5 years' extreme weather conditions for the peak load forecast, which was used for transmission planning studies for the Hazard Area. Whether use of 1 in 10 years' extreme weather load forecast for Kentucky Power provides any merits needs additional analysis and assessment.

Upon reviewing AEP's load forecast approach, especially the long-term forecast approach for Kentucky Power and its local areas, BWG/Auriga found that the methodologies used and variables considered are reasonable and in accordance with the existing industry practices in load forecast.

2.4 GENERATION DISPATCH SCENARIOS

2.4.1 Introduction

Generation forecasts are more challenging in the deregulated environment. Normally generation forecasts are based on filed requests for plant permits, forecasts of future load, and

[29] 1 in 5 (10) years extreme weather means the likelihood of occurrence of such extreme weather is 1 out of 5 (10) years. Load forecast based on 1 in 10 year's extreme weather data will produce higher demand than 1 in 5 years. Consequently, transmission planning based on 1 in 10 years extreme weather load forecast will lead to more conservative (higher cost but with less risk) results than that based on 1 in 5 years extreme weather forecast. There is no regulation on what type of extreme weather load forecast must be used and each planning entity has its own practice.

[30] July 8, 2005 Interview with AEP transmission planning personnel.

assumptions regarding the transmission system. Future transmission needs to be identified in system studies are based on load forecasts and assumed generation resources. For many transmission planning studies, analysis of generation sensitivity is necessary to model the variations in dispatch that routinely occur at each load level. The purpose is to bias the generation dispatch scenarios that would most stress the transmission system under study. A merit order based generation dispatch[31] is usually used as a starting point from which to stress the transmission system. A merit order based dispatch can be approximated based on available information such as fuel type and historical information regarding unit commitment.

2.4.2 AEP's approach

AEP transmission planning used generation resources that were already approved to be built for transmission planning for the future years. This information was obtained from AEP's resource planning organization. AEP did not perform generation sensitivity analysis or vary generation dispatch scenarios for the load flow cases under study since there is no generation in the Hazard Area and the reliability problems in the Hazard Area are insensitive to the allocation of generation resources outside the area.[32]

2.4.3 Discussion

The thermal overload and low voltage problems in the Hazard Area are dependent on the loading levels of the three transmission lines importing power from outside to inside the area. These line loading levels are not directly impacted by the outside generation resource allocations. Therefore, the generation dispatch scenarios would have little impact on the solution to the reliability problems of the Hazard Area. Based on these facts, BWG/Auriga concludes that it is reasonable to neglect the generation dispatch scenario variations. Transmission solutions developed under one generation dispatch scenario should well be applicable to other situations with different generation dispatch scenarios.

2.5 Reactive Power Needs

2.5.1 Introduction

Reactive power plays a vital role in maintaining proper voltage levels and avoiding voltage instability or collapse phenomena hence improving system reliability. Sufficient reactive resources must be located throughout the electric systems, with a balance between static and dynamic characteristics. Both static and dynamic reactive power sources are needed to supply the reactive power requirements of customer demands and the reactive power losses in the transmission and distribution systems, and provide adequate system voltage support and

[31] A merit order based dispatch means dispatching the generating units starting with the least expensive one.
[32] July 8, 2005 Interview with AEP transmission planning personnel.

control during normal and contingency operating conditions. Static reactive power sources are those providing reactive power and voltage support in the steady state conditions such as series and shunt capacitors. They are not fast enough to supply the required reactive power during disturbances. Dynamic reactive power sources are those that can provide reactive power very quickly such as synchronous generators, synchronous condensers, STATCOMs, etc. Dynamic reactive power is needed during disturbances.

Reactive power can not be transmitted over a long distance and hence must be generated and balanced locally. Reactive power adequacy is essentially a local problem.

2.5.2 AEP's approach

AEP estimates the reactive power loads based on the measured power factor for each load area. AEP provides reactive power corrections as load increases within an area to maintain proper bus voltage level. Where reactive power assessments indicate a need for additional power factor corrections, AEP will propose appropriate reinforcements to meet its design goal so that each voltage level is not a reactive burden to its source system. There are a number of reactive power sources within or near the Hazard Area. These include a ± 125 MVAr static var compensator (SVC) installed at the Beaver Creek Station 138 kV bus and several switchable shunt capacitors in the area. There is also a capacitor bank connected in a bridge configuration at the Leslie Station.[33]

2.5.3 Discussion

While static reactive power provides the needs in the steady state, the dynamic reactive power provides support and voltage control that are essential during power system disturbances. AEP allocated both static and dynamic reactive power sources in or near the Hazard Area. From the load flow simulation results, BWG/Auriga found that the proper combination of different types of reactive power sources is adequate for voltage support in the Hazard Area.

2.6 CONTINGENCY SELECTION

2.6.1 Introduction

Transmission system reliability assessment requires an examination of the system's responses to normal as well as contingency operating conditions. Contingencies are system elements that are assumed to be out of service (disconnected from the system). There can be many contingencies in the system. Some are more severe than others. It is neither practical nor necessary to simulate every contingency, especially for large transmission systems. Rather, only a selected number of contingencies are usually simulated. In the deterministic planning

[33] July 8, 2005 Interview with AEP and Kentucky Power's response to BWG data request BWG-3.

approach, the N-1 contingency rule is widely used as a fundamental requirement for meeting system performance criteria. If system performance is not acceptable for the N-1 contingencies, steps must be taken to reinforce the system to make it within the acceptable performance criteria. However, there may be circumstances where a multiple contingency event (N-2 or N-k, k>2) may need to be considered due to its severe risk to the transmission system. For example, such a contingency event may be the loss of a transmission facility during a period of maintenance or repair of another transmission facility or a multiple contingency event due to a common cause such as a fire, flood, etc., or the failure of a transmission tower supporting multiple circuits. Whether such a multiple contingency event needs consideration is up to the transmission planning organization to evaluate its probability and consequences.

2.6.2 AEP's approach

AEP's contingency selection approach is based on guidelines as stated in NERC and ECAR reliability criteria. The typical approach for contingency selection at AEP is to use engineering judgment based on contingency screening results from the computer simulation program.[34] For the Hazard Area, AEP applied the N-1 contingency rule. As mentioned earlier, there are three transmission lines that link the Hazard Area to the rest of the system. Loss of one of them is a credible contingency that needs to be considered. On the other hand, outage of the Fleming – Collier 69 kV line is not as severe contingency as loss of the other two lines. Therefore, the contingencies used in the Hazard Area system study were loss of the Pineville – Hazard 161 kV line and loss of the Beaver Creek – Hazard 138 kV line.

2.6.3 Discussion

AEP's contingency selection approach is typical of industry practices, especially for large transmission systems, where there are thousands of transmission elements in the system and it is not practical to consider all possible contingencies. For the Hazard Area transmission planning, it is adequate and practical to consider all credible single contingencies, which are loss of the Beaver Creek – Hazard 138 kV line and loss of the Pineville – Hazard 161 kV line. This is in accordance with the industry practices for subtransmission planning where N-1 is normally considered.

2.7 Load Flow and Stability Analysis

2.7.1 Introduction

Load flow analysis and stability analysis are used to evaluate system steady state and dynamic performances, respectively. Thermal overloads and voltage limit violations can be identified

[34] July 8, 2005 Interview with AEP transmission planning personnel.

through load flow analysis whereas stability analysis will determine whether any generator will lose synchronism with other generators in the system.

Load flow and stability analysis require complete, accurate, and up-to-date modeling data in order to produce accurate system study results. The modeling data include information on system elements, system configuration, demand, generation, and power transactions. All system elements including transmission lines, transformers, generators, shunt capacitors, and etc., must be properly modeled in order to correctly simulate the transmission system behaviors.

2.7.2 AEP's approach

ECAR requires its member transmission service providers to develop and maintain system data and to provide that data to ECAR upon request.[35] ECAR maintains a number of base cases under various operating conditions with system data from its members. ECAR members can request these base cases for their system studies. AEP's power flow models used in the Hazard Area system study were developed based on ECAR's power flow base case for the winter peak conditions. AEP took the ECAR base case and replaced the representation of Kentucky Power with more detailed models.[36] The detailed models included the 69 kV and higher voltage systems. AEP performed detailed power flow studies for the 2004 and 2007 winter peak cases under normal and contingency conditions. The software programs used for load flow studies were PSS/E from Siemens PTI and PowerWorld Simulator from PowerWorld Corporation. PSS/E has been widely used in the industry for decades. PowerWorld Simulator is a newer program with visual capabilities for presenting power flow simulation results.

The Hazard Area is a load area with no generators installed. Therefore, there were no stability issues and stability analysis was not needed.[37]

2.7.3 Discussion

BWG/Auriga reviewed AEP's load flow cases for 2004 and 2007 and system modeling data and found that all system elements were properly modeled in sufficient detail.

2.8 SHORT CIRCUIT ANALYSIS AND SYSTEM PROTECTION STUDIES

2.8.1 Introduction

---

[35] ECAR Document No.1, July 1998.
[36] July 8, 2005 Interview with AEP.
[37] July 8, 2005 Interview with AEP.

When a short-circuit fault occurs, current flowing through the transmission system elements can be significantly higher than the normal current. In order to isolate the fault from the system, the corresponding circuit breakers must have sufficient fault breaking capability to ensure that faulted component can be removed from the system quickly and safely. Short-circuit analysis is done to calculate the fault capacity (MVA) for a specified fault and help ensure that the fault interrupting devices have the proper interrupting ratings so that personnel and equipment are not damaged.

System protection studies are usually done together with short-circuit analysis. A protection study maximizes power system selectivity by isolating faults to the nearest protective device, as well as helping avoid nuisance operations that are due to transformer inrush or motor starting operations.

2.8.2 AEP's approach

AEP performed short-circuit simulations for single phase and three phase faults at the Hazard end of the Beaver Creek – Hazard 138 kV line and the Hazard end of the Pineville – Hazard 161 kV line. The software program used for the simulations was ASPEN OneLiner, a PC-based short-circuit and relay coordination program from ASPEN.[38]

At this stage, AEP did not perform protection studies but will do so once the project is approved.[39]

2.8.3 Discussion

BWG/Auriga witnessed the short-circuit simulations performed by AEP during the July 8, 2005 interview meeting at Columbus, OH and found that the fault capacities were well below the interrupting capacities of the circuit breakers. For system protection studies, BWG/Auriga concurs with AEP that these studies should be performed once the proposed project is approved.

2.9 SUMMARY

BWG/Auriga reviewed AEP's approach in the following aspects that are important to transmission planning: general planning approach, reliability criteria, load forecast, generation dispatch, reactive power needs, contingency selection, load flow and stability analysis, short-circuit analysis, and protection studies.

AEP's general planning approach is consistent with Good Utility Practice and industry trends. It also follows the guidelines in the NERC and ECAR reliability criteria. AEP's study

[38] July 8, 2005 Interview with AEP.
[39] July 8, 2005 Interview with AEP.

approach in the Hazard Area planning studies is appropriate and sufficient for evaluating the need for transmission reinforcement projects.

AEP's transmission planning reliability criteria (N-0 and N-1 criteria) as applied to the Hazard Area system is reasonable compared with NERC and ECAR reliability criteria and planning practices in other electric utilities.

Regarding load forecast, AEP's methodologies and variables considered are reasonable and in accordance with the existing industry practices.

AEP did not consider varying generation dispatch scenarios for the Hazard Area system studies. This is reasonable since there is no generation in the Hazard Area and the area system performance is insensitive to outside generation sources.

AEP allocated adequate different types of reactive sources for voltage support in the Hazard Area.

AEP's contingency selection approach is typical of industry practices, especially for large transmission systems. For the Hazard Area transmission planning, AEP considered all credible single contingencies. This is in accordance with the industry practices for subtransmission planning where N-1 is normally considered.

AEP used proper transmission system element models in sufficient details in all its load flow cases.

AEP properly considered short-circuit analysis and protection studies in its planning process.

Overall, BWG/Auriga concludes that AEP used an appropriate approach for its transmission planning studies. Specifically, it used practical and reasonable assumptions, methodologies, techniques, and tools for the Kentucky Power - Hazard Area transmission system studies.

3. ASSESSMENT OF POTENTIAL SOLUTIONS

For long-term transmission planning studies, if there are any violations of the reliability criteria under any credible contingency, a transmission reinforcement plan must be developed to make the transmission system performance within the acceptable criteria. There can be various potential alternatives from different viewpoints. Generally, potential solutions include transmission solutions as well as non-transmission solutions. Typical transmission solutions would include building new lines, adding reactive power devices, reconductoring, and other transmission facility upgrades. Adding new generators and direct load control are examples of non-transmission solutions. Obviously, non-transmission solutions are only applicable to utilities and transmission service providers who own generation assets or have access to those potential solutions.

Regarding the urgency for a solution to the identified problems in the Hazard Area, AEP computed the project priority index[40] as described in its Project Priority Guide (PPG) associated with the problems. The project priority index computed was 4.0×10^{-2}.[41] This index value is greater than the threshold value of 2.0×10^{-2}, which is required for proposing any area transmission reinforcement projects.[42]

3.1 WOOTEN 161 KV INTERCONNECTION

3.1.1 Project description

Kentucky Power proposed the Wooten 161 kV Interconnection project, which would interconnect LG&E's Delvinta – Arnold 161 kV line with Kentucky Power's Pineville – Hazard 161 kV line. In support of this interconnection, a new switching station is also required. The proposed new Wooten switching station will be located 5,751 feet from the connection point between the above mentioned two 161 kV lines. The Wooten Station will include three 161 kV circuit breakers, metering, and associated facilities. System protection upgrades will also be required at remote stations.

Figure 3-1 shows a diagram for the Wooten 161 kV Interconnection Project.[43]

[40] Sub-Transmission Planning Criteria, AEP's Presentation, June 3, 2005
[41] Hazard Area Study, AEP, April 2003 (Kentucky Power's response to BWG data request BWG-5).
[42] July 8, 2005 Interview with AEP.
[43] Load flow study result presentation file, Case No 2005-00101 Hazard Area Study.ppt (Kentucky Power's response to BWG data request BWG-5).

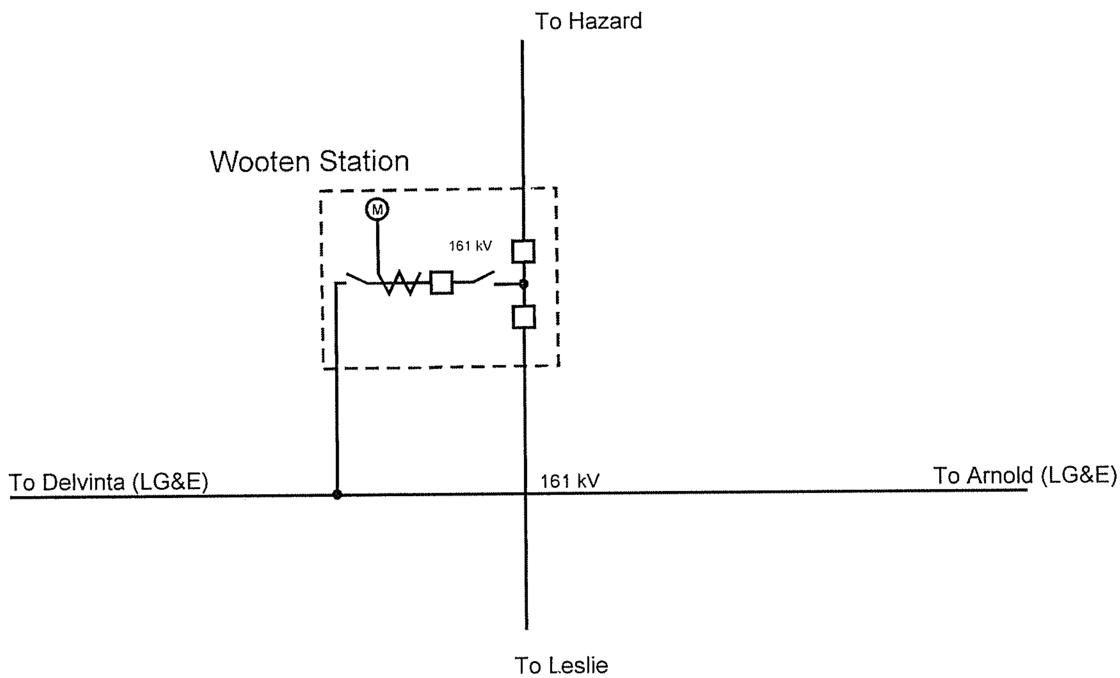


Figure 3-1 Wooten 161 kV Interconnection

Theoretically, it would be ideal to site the new switching station in the vicinity of the 161 kV line crossing point, as shown in Figure 3-2.[44] However, due to difficulty in obtaining a suitable site with access by large trucks for construction, the line crossing point could not be selected as the site for the new switching station. Using a topographical map, AEP identified seven potential locations. A field inspection eliminated five of the sites because of the proximity of existing homes, physical constraints of line construction to the site, limited or no access to the site by heavy equipment or the large amount of fill required to raise the site above the flood level. Of the remaining potential sites, Kentucky Power reached an agreement with the owner of one site for constructing the new station. This site is located 5,751 feet from the transmission line crossing point.[45]

[44] Hazard Area Study, AEP, April 2003.
[45] June 17, 2005 Kentucky Power Application.

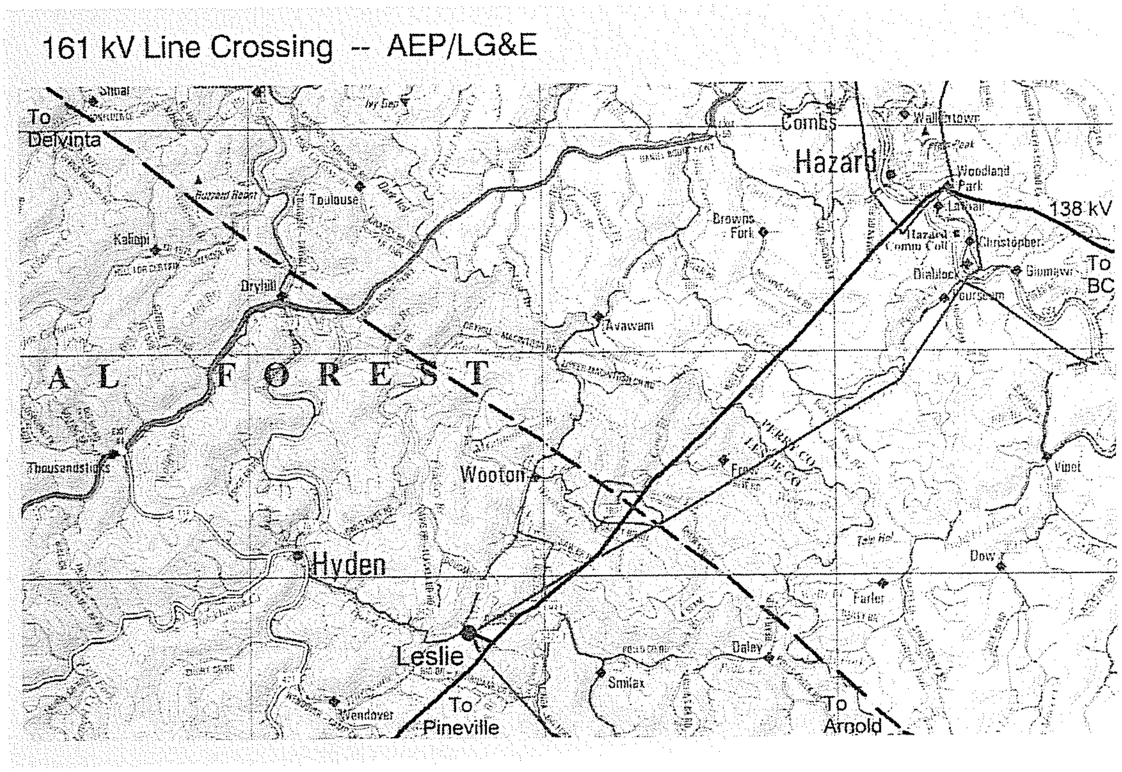


Figure 3-2 Kentucky Power's Pineville – Hazard and LG&E's Delvinta – Arnold 161 kV Line Crossing

3.1.2 Technical and Economic Assessment

3.1.2.1 Technical Assessment

AEP transmission planning performed load flow studies for the 2004 and 2007 winter peak conditions. AEP provided twelve (12) study result files in the PowerWorld binary file format to BWG/Auriga.[46] BWG/Auriga then used PowerWorld Viewer to retrieve the information on the system conditions for the review. These load flow result files represent the following operating conditions:

- 2004 winter peak without Wooten Interconnection with all elements in service
- 2004 winter peak without Wooten Interconnection with Pineville – Hazard 161 kV line outage

[46] Load flow study result files in PowerWorld binary format that can be viewed by PowerWorld Viewer (Kentucky Power's response to BWG data request BWG-5).

- 2004 winter peak without Wooten Interconnection with Beaver Creek – Hazard 138 kV line outage
- 2004 winter peak with Wooten Interconnection with all elements in service
- 2004 winter peak with Wooten Interconnection with Pineville – Hazard 161 kV line outage
- 2004 winter peak with Wooten Interconnection with Beaver Creek – Hazard 138 kV line outage
- 2007 winter peak without Wooten Interconnection with all elements in service
- 2007 winter peak without Wooten Interconnection with Pineville – Hazard 161 kV line outage
- 2007 winter peak without Wooten Interconnection with Beaver Creek – Hazard 138 kV line outage
- 2007 winter peak with Wooten Interconnection with all elements in service
- 2007 winter peak with Wooten Interconnection with Pineville – Hazard 161 kV line outage
- 2007 winter peak with Wooten Interconnection with Beaver Creek – Hazard 138 kV line outage

The study results showed that the proposed Wooten Interconnection would eliminate the problems identified in Section 1, i.e., transmission line thermal overloads and low voltages in the Hazard Area with outage of either the Pineville – Hazard 161 kV line or the Beaver Creek – Hazard 138 kV line. Therefore, the transmission system performance would meet the AEP reliability criteria.

Table 3-1 shows line flows for the 2004 Winter Peak Case under the Pineville – Hazard 161 kV line contingency with and without Wooten Interconnection. It can be seen that the thermal overloads on the Beaver Creek – Hazard 138 kV line and the Fleming – Collier 69 kV line would be eliminated. These two lines only carried about 40% (151 MW) of the Hazard Area load while the rest would be supplied through the new interconnection. The corresponding voltage profile is shown in Figure 3-3 and Figure 3-4.

Table 3-1 Line Flows for the 2004 Winter Peak Case with and without Wooten Interconnection: Pineville – Hazard 161 kV Line Contingency

Transmission Line Segment	Without Wooten Interconnection (% of Normal Rating)	With Wooten Interconnection (% of Normal Rating)
Pineville – Hazard 161 kV	0	0
Beaver Creek – Hazard 138 kV	275 (120%)	87 (38%)
Fleming – Collier 69 kV	116 (121%)	64 (67%)
Wooten Interconnection	N/A	224

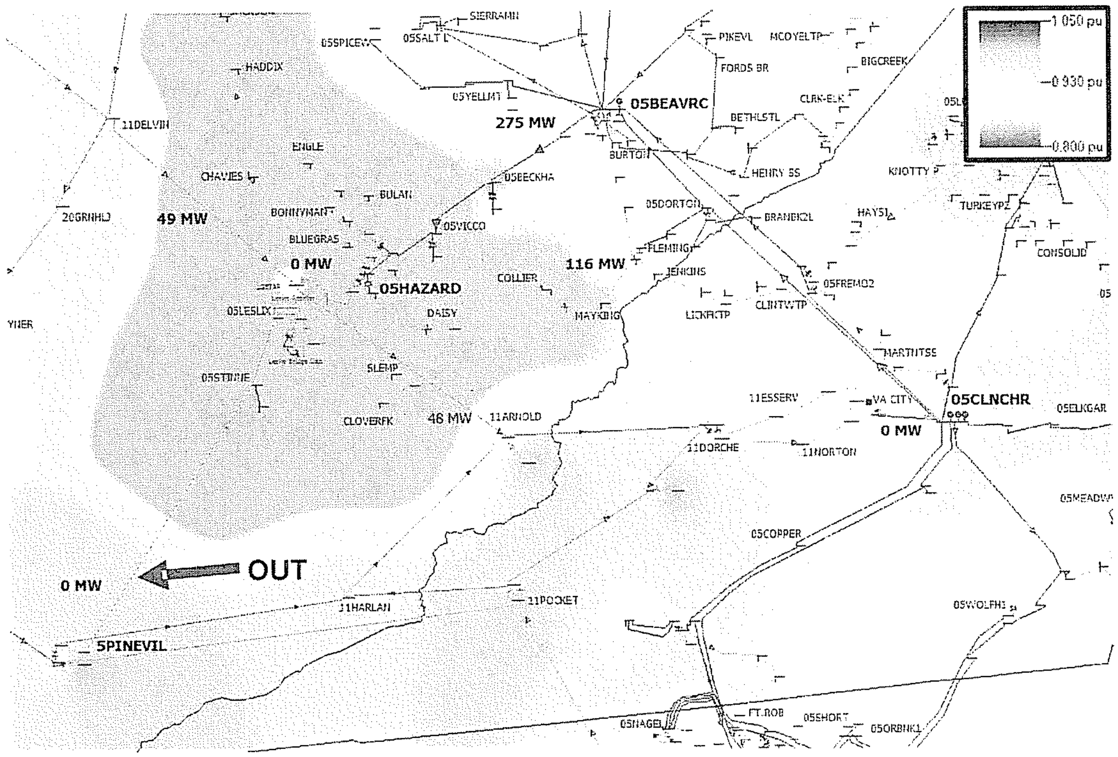


Figure 3-3 Voltage Profile in the Hazard Area for the 2004 Winter Peak Case Pineville – Hazard 161 kV Line Contingency without Wooten Interconnection

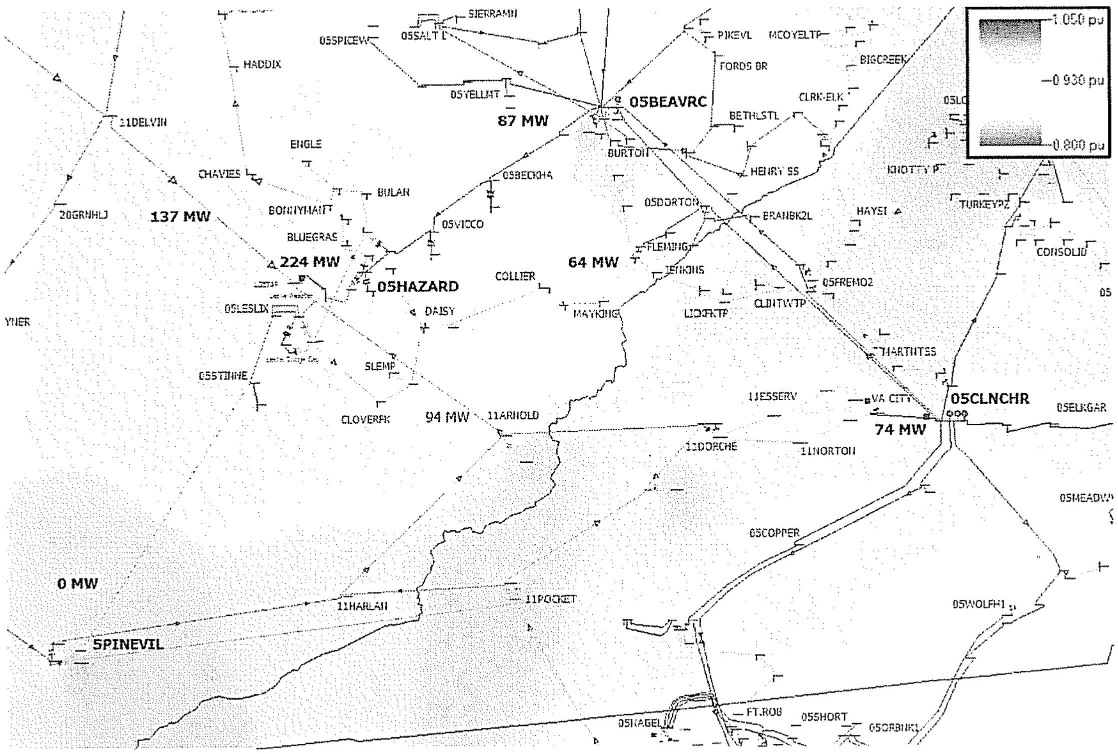


Figure 3-4 Voltage Profile in the Hazard Area for the 2004 Winter Peak Case Pineville – Hazard 161 kV Line Contingency with Wooten Interconnection

As shown in Figure 3-3, voltages at most of the buses are way below the 0.92 desired voltage level with the Pineville- Hazard 161 kV line outage. Table 3-2[47] lists the values of the bus voltages in the Hazard Area for the 2004 Winter Peak Case under the Pineville – Hazard 161 kV line contingency with and without the Wooten Interconnection. It can be seen from Table 3-2 that the bus voltages in the entire Hazard Area would be boosted to the acceptable values (0.92 or higher) specified in the AEP transmission planning reliability criteria. Note that the voltages at buses HADDIX, JACKSON, and 05HELECH were still below 0.92. These three 69 kV buses were along a radial line on the far north side of the Hazard Area subtransmission system. These bus voltages were already very low even under normal operating conditions. This is a very local problem and it should be addressed separately. For example, one of the potential solutions may be adding some reactive power sources such as shunt capacitors. AEP is currently investigating the solution to this local problem.

[47] Based on the Hazard Area bus voltages in the Microsoft Excel saved from PowerWorld Viewer by Auriga Staff.

Table 3-2 Hazard Area Bus Voltages for the 2004 Winter Peak Case under the Pineville – Hazard 161 kV Line Contingency with and without Wooten Interconnection

BusNum	BusName	BusNomVolt	Without Wooten Interconnection BusPUVolt	With Wooten Interconnection BusPUVolt
3383	SPICWD L	12	0.93672	0.9983
3364	HARBRT L	12	0.93666	0.99824
3387	05INDEX	69	0.91335	0.92236
3393	BEEFHIDL	34.5	0.913	0.98778
3380	JENKINS	69	0.91087	1.0111
3361	FLEMING	69	0.90588	1.01404
3351	BECKHM L	34.5	0.88977	1.01478
3395	MAYKING	69	0.79887	0.98489
3386	WHITSBRG	69	0.76705	0.97869
3394	GOLDENOK	69	0.76705	0.97869
3385	VICC L	34.5	0.72685	1.00657
3357	COLLIER	69	0.72188	0.96725
3360	TALENTBR	69	0.66412	0.96477
3359	DAISY	69	0.64227	0.96372
3366	HAZARD 2	69	0.64048	0.98296
3384	STINNT L	34.5	0.64029	0.97326
3374	JEFF	69	0.63996	0.97614
3396	BRIDGE-C	115	0.63703	0.97121
3352	BLUEGRAS	69	0.62346	0.97401
3391	HAZARD1-	69	0.62262	0.96817
3377	LESLIE	69	0.61198	0.95491
3358	COMBS	69	0.60441	0.96441
3356	CLOVERFK	69	0.60346	0.94605
3382	SLEMPTAP	69	0.60104	0.94056
3354	BULAN	69	0.60043	0.95753
3381	SLEMP	69	0.59987	0.93971
3388	SHAMROCK	69	0.58697	0.95072
3353	BONNYMAN	69	0.58385	0.9513
3392	ENGLE	69	0.57513	0.94222
3355	CHAVIES	69	0.5484	0.93749
3389	HAZARDT4	34.5	0.52967	0.9214
3363	HADDIX	69	0.50892	0.91312
3372	05HELECH	69	0.50101	0.90885
3373	JACKSON	69	0.50101	0.90885

The proposed interconnection also provides improvement to system loading patterns under normal operating conditions. Table 3-3 is a comparison of line flows for the 2004 Winter

Peak Case under normal conditions with and without Wooten Interconnection. It can be seen that with the new interconnection the MW loading on the Fleming – Collier 69 kV line would be reduced from 93% to 76% of its normal rating. Thus, there would be more thermal capacity margin on this line, which is beneficial to the reliable supply to the Hazard Area loads.

Table 3-3 Line Flows with and without Wooten Interconnection for the 2004 Winter Peak Case under Normal Conditions

Transmission Line Segment	Without Wooten Interconnection (% of Normal Rating)	With Wooten Interconnection (% of Normal Rating)
Pineville – Hazard 161 kV	190 (60%)	104 (33%)
Beaver Creek – Hazard 138 kV	122 (60%)	64 (32%)
Fleming – Collier 69 kV	71 (93%)	58 (76%)
Wooten Interconnection	N/A	150

BWG/Auriga also reviewed AEP's load flow study results under the Beaver Creek – Hazard 138 kV line contingency for the 2004 Winter Peak Case as well as those for the 2007 Winter Peak Case. Note that without the Wooten Interconnection the load flow for the 2007 Winter Peak Case did not converge to a solution under the Beaver Creek – Hazard 138 kV line outage.[48] BWG/Auriga found that the proposed Wooten Interconnection would eliminate all thermal overloads and low voltage problems for both 2004 and 2007 Winter Peak Cases under both contingencies. The complete load flow study results are shown in Appendix A.

In addition to elimination of the thermal overloads and low voltage problems under single contingencies, the total system loss would be reduced by about 10 MW, which has a capitalized value of about $10 million[49].

As mentioned in Section 1, the Hazard Area is one of four load areas in the service territory of the Kentucky Power. It is interconnected with the rest of the AEP system and the LG&E system. As any transmission reinforcement in one part of the system impacts or is impacted by other parts of the system or the neighboring systems, AEP stated that it coordinated with LG&E regarding the impacts of the proposed Wooten Interconnection on the neighboring LG&E system[50]. LG&E then conducted necessary load flow studies and confirmed with AEP that the proposed interconnection would not have any adverse impacts on the LG&E system. BWG/Auriga did not verify the results of LG&E studies.

[48] Load flow is solved through a number of mathematical iterations. When the system is properly conditioned, the load flow should converge to a physically meaningful solution with a proper mathematical solution method. One of the reasons for non-convergence is due to some highly stressed operating conditions that will not lead to a physically meaningful solution.

[49] AEP – LG&E Interconnections Roanoke Transmission Region – Kentucky & Virginia, AEP East Area Transmission Planning, October 2004 (Kentucky Power's response to BWG data request BWG-8).

[50] Hazard Area 161 kV and Virginia City 138 kV Interconnections Memorandum of Understanding, August 2004 (Kentucky Power's response to BWG data request BWG-8).

3.1.2.2 Economic Assessment

The proposed Wooten Interconnection would require a short (5,751 feet) 161 kV line, a new switching station including three 161 kV circuit breakers, metering and associated facilities, and system protection upgrades at remote stations. AEP transmission planning prepared a detailed cost estimate for the Wooten Interconnection project for all of the above facilities, which BWG/Auriga reviewed. The total estimated cost is approximately $4.2 million, with $2.8 million for the Wooten and other station work and $1.4 million for the transmission line work.[51]

AEP also prioritizes all of its transmission projects using strategic objective index based on reliability criteria and other factors. This project is ranked fourth in priority within the AEP system.[52]

3.1.3 Summary

AEP performed load flow studies for the 2004 and 2007 Winter Peak Cases under normal and contingency conditions. The study results showed that the proposed Wooten Interconnection would eliminate all thermal overloads and low voltage problems and provide the necessary infrastructure for adequate and reliable power supply to the Hazard Area for the next 3 – 5 years (at least up to 2007). BWG/Auriga reviewed all load flow study results performed by AEP and found that they were reasonable and supported AEP's proposed solution. Another benefit is that this interconnection would provide a different source of power supply from LG&E to the Hazard Area. This would improve the overall reliability of power supply in this area.

AEP also prepared a cost estimate for the proposed Wooten Interconnection. The total estimated cost was about $4.2 million. BWG/Auriga reviewed AEP's cost estimate and found that it is adequate and reasonable.

3.2 HARBERT – HAZARD 138 KV LINE ADDITION

3.2.1 Project Description

A possible alternative proposed by AEP is to construct a new 138 kV line from the Harbert Station to the Hazard Station. This Harbert – Hazard 138 kV Line Addition project would include an approximately 19 mile long 138 kV line as well as circuit breakers and associated facilities at the Harbert Station and the Hazard Station.[53]

[51] AEP – LG&E Interconnections Roanoke Transmission Region – Kentucky & Virginia, AEP East Area Transmission Planning, October 2004 (Kentucky Power's response to BWG data request BWG-8).
[52] AEP-LGE Project Priority Summary provided to BWG on July 12, 2005.
[53] Load flow study result file, Case No 2005-00101 Hazard Area Study.ppt (Kentucky Power's response to BWG data request BWG-8).

This alternative was based on a signed contract with an independent power producer (IPP) who would have built a generating plant and would have required a new transmission line interconnecting with Kentucky Power[54]. Such a new interconnection would have solved the transmission system reliability problems in the Hazard Area while transferring power from the IPP plant to the Hazard Area loads. However, the IPP generation project has been delayed[55].

Figure 3-5 shows a diagram for the Harbert – Hazard 138 kV Line Addition Project.

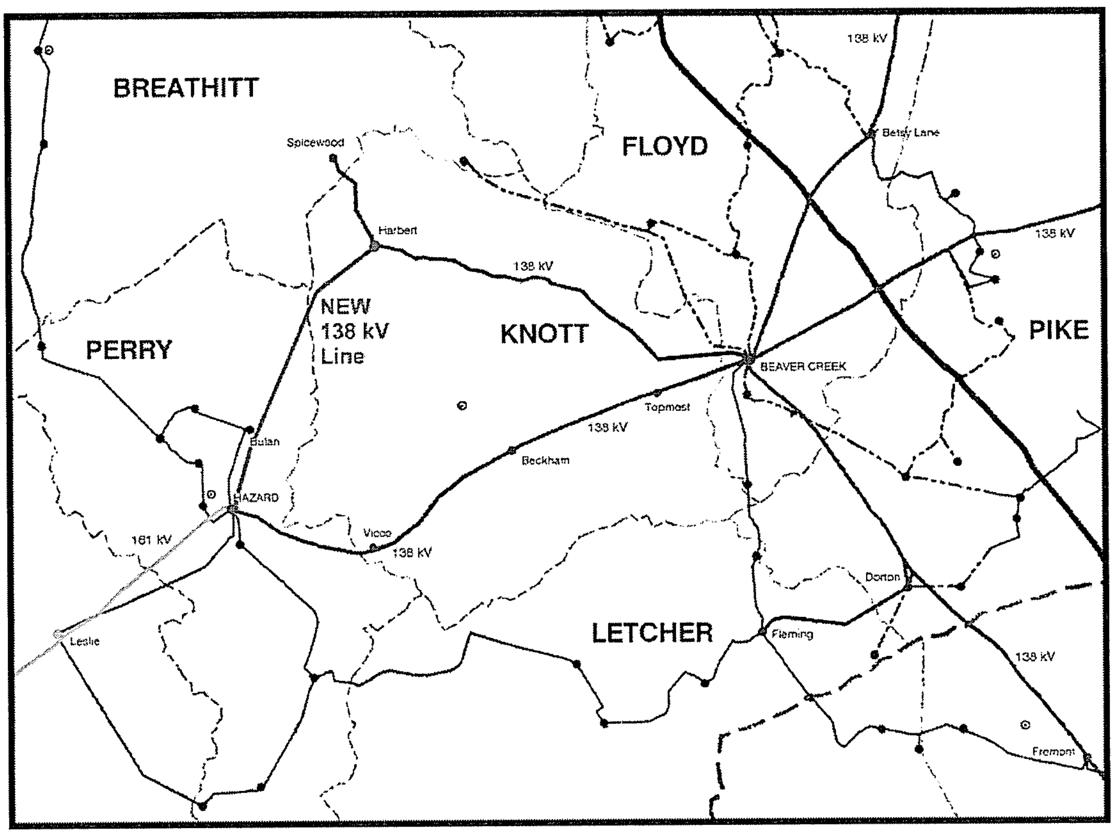


Figure 3-5 Harbert – Hazard 138 kV Line Addition Project

3.2.2 Technical Assessment

The addition of the Harbert – Hazard 138 kV line would provide an additional link that would transfer power from outside to inside the Hazard Area. AEP concluded that this line addition

[54] See Case No. 2002-00149, The Application Of Kentucky Mountain Power, LLC / Enviropower, LLC For A Merchant Power Plant Construction Certificate In Knott County, Kentucky Near Talcum.
[55] Interview with AEP transmission planning personnel on July 8, 2005.

would be a technically viable alternative to the proposed Wooten Interconnection. AEP did not perform any load flow studies for this alternative. Rather, its conclusions were based on its previous load flow studies associated with the IPP application for the new interconnection several years ago.[56]

3.2.3 Economic Assessment

AEP prepared a cost estimate for the proposed Harbert – Hazard 138 kV line addition. The total estimated cost was about $15 million.[57]

3.2.4 Summary

AEP stated that the Harbert – Hazard 138 kV line addition is a technically viable alternative to the proposed Wooten Interconnection as it would eliminate all thermal overloads and low voltage problems under single contingency conditions. BWG/Auriga did not review AEP's previous load flow study results and hence doe not have enough information to confirm that this alternative is technically viable. Based on BWG/Auriga's experience, however, this is not a desirable solution, particularly if the power plant is not built by the IPP.

AEP also did a cost estimate for the Harbert – Hazard 138 kV line addition. The total estimated cost was about $15 million. BWG/Auriga reviewed AEP's cost estimate and found that it is adequate and reasonable.

3.3 OTHER ALTERNATIVES

In addition to the proposed Wooten Interconnection and the Harbert – Hazard 138 kV Line Addition alternative that AEP considered, BWG/Auriga discussed the following other alternatives with AEP transmission planning personnel at the July 8, 2005 interview meeting at Gahanna, OH.

3.3.1 Fleming – Hazard 138 kV Line Addition

BWG/Auriga concurs with AEP that the Fleming – Hazard 138 kV line addition would cost more than the Harbert – Hazard 138 kV line addition alternative without any other tangible benefits.

3.3.2 Reconductoring

[56] July 8, 2005 Interview with AEP.
[57] Provided to BWG on July 12, 2005 (Kentucky Power's response to BWG data request BWG-8, BWG-9).

Reconductoring an existing line to a larger conductor can increase the power carrying capacity of the line. However, the line will be out of service during the reconductoring process. AEP stated that reconductoring either the Pineville – Hazard 161 kV line or the Beaver Creek – Hazard 138 kV line or both would cost much more than the Wooten Interconnection. BWG/Auriga concurs with AEP that reconductoring is not a cost-effective solution.

3.3.3 Generation Additions

Though generation additions to the local area can replace the needs for transmission reinforcement, building new power plants generally costs more and takes a longer time. BWG/Auriga concurs with AEP that adding new generation to the Hazard Area is not a viable solution.

3.4 SUMMARY

BWG/Auriga reviewed all twelve (12) load flow study result files (2004 and 2007 Case Studies) provided by AEP for the proposed Wooten Interconnection. In addition, BWG/Auriga had further discussions with AEP on July 8, 2005 and requested additional information on its load flow studies. BWG/Auriga found that the study results obtained by AEP were reasonable and adequate to support the proposed interconnection project. BWG/Auriga concurs with AEP that the Wooten Interconnection is the most technically and economically viable solution to the reliability problems identified in the Hazard Area. With the Wooten Interconnection, the thermal overloads and low voltage problems would be eliminated and the AEP transmission planning criteria would be met. BWG/Auriga also reviewed AEP's cost estimate for the Wooten Interconnection and found that the total estimated cost of $4.2 million is reasonable.

BWG/Auriga also reviewed the alternative to the Wooten Interconnection, i.e., the Harbert – Hazard 138 kV Line Addition. This alternative was based on a previously proposed new interconnection associated with an IPP application, which has been delayed. AEP drew a conclusion that this alternative would be a technically viable alternative based on the previous load flow studies conducted for the IPP application. BWG/Auriga did not review the previous study results and does not have enough information to confirm AEP's conclusion. BWG/Auriga reviewed AEP's cost estimate for this alternative and found that the total estimated cost of about $15 million is reasonable. It can be seen that this alternative would cost over $10 million more than the proposed Wooten Interconnection. There is no additional information available to BWG/Auriga to support that this alternative would bring sufficient extra benefits so that the extra cost would be justified. Therefore, BWG/Auriga concurs with AEP that this alternative is not a cost-effective solution to the Hazard Area reliability problems.

During the July 8, 2005 interview meeting at Columbus, OH, BWG/Auriga also discussed other potential alternatives including Fleming – Hazard 138 kV line addition, reconductoring the 138 kV or 161 kV or both lines linking to the Hazard Area, and generation additions. Based on the information provided by AEP, none of these alternatives is a viable solution.

4. CONCLUSIONS

Based on the review of the filing document and the materials provided by AEP as well as the information obtained at the interview meeting with AEP on July 8, 2005, BWG/Auriga makes the following conclusions.

- Kentucky Power needs to reinforce the Hazard Area transmission system to ensure adequate and reliable power supply to the area loads.

- The proposed Wooten Interconnection project is the most technically and economically viable solution to the Hazard Area problems.

- The Harbert – Hazard 138 kV line alternative, which may meet the needs technically, is not a cost-effective solution.

APPENDIX A LOAD FLOW STUDY RESULTS FOR WOOTEN INTERCONNECTION

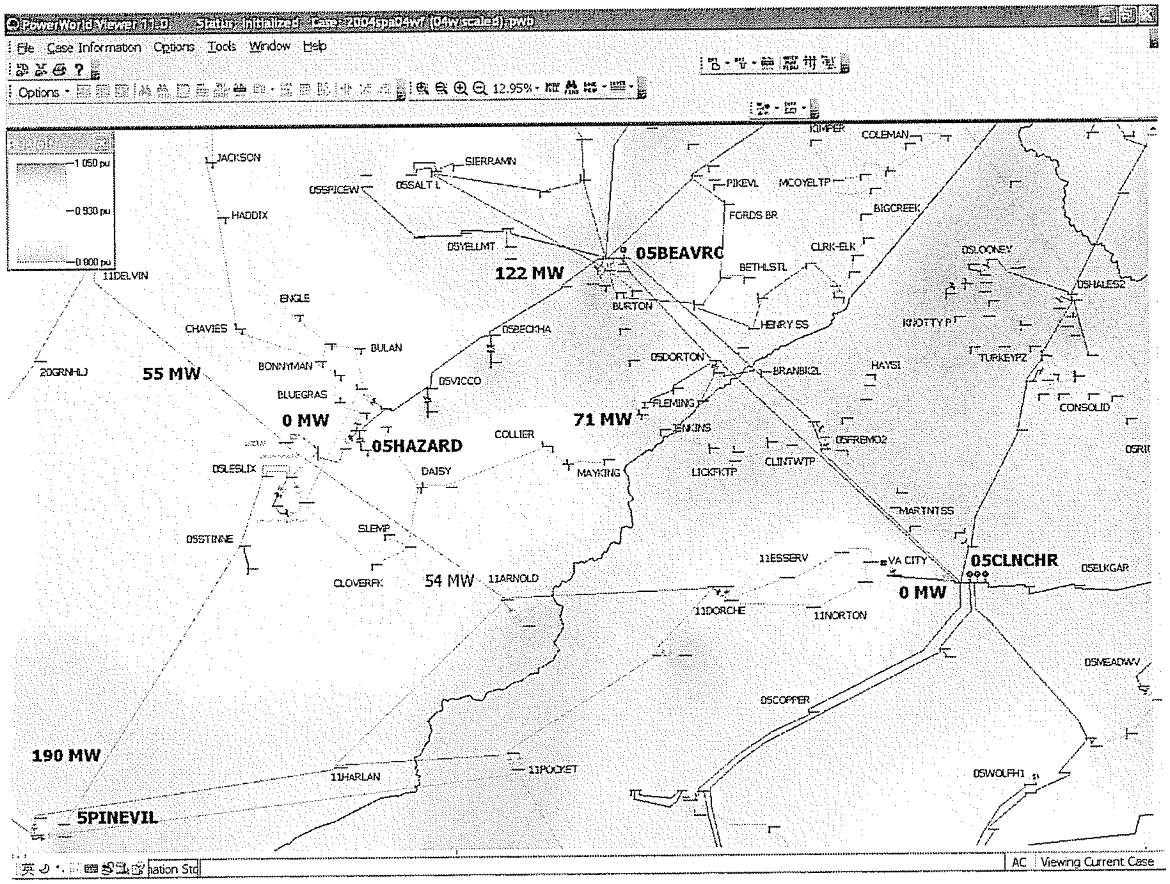


Figure A-1 Line Flows and Voltage Profile
2004 Winter Peak Normal Conditions without Wooten Interconnection

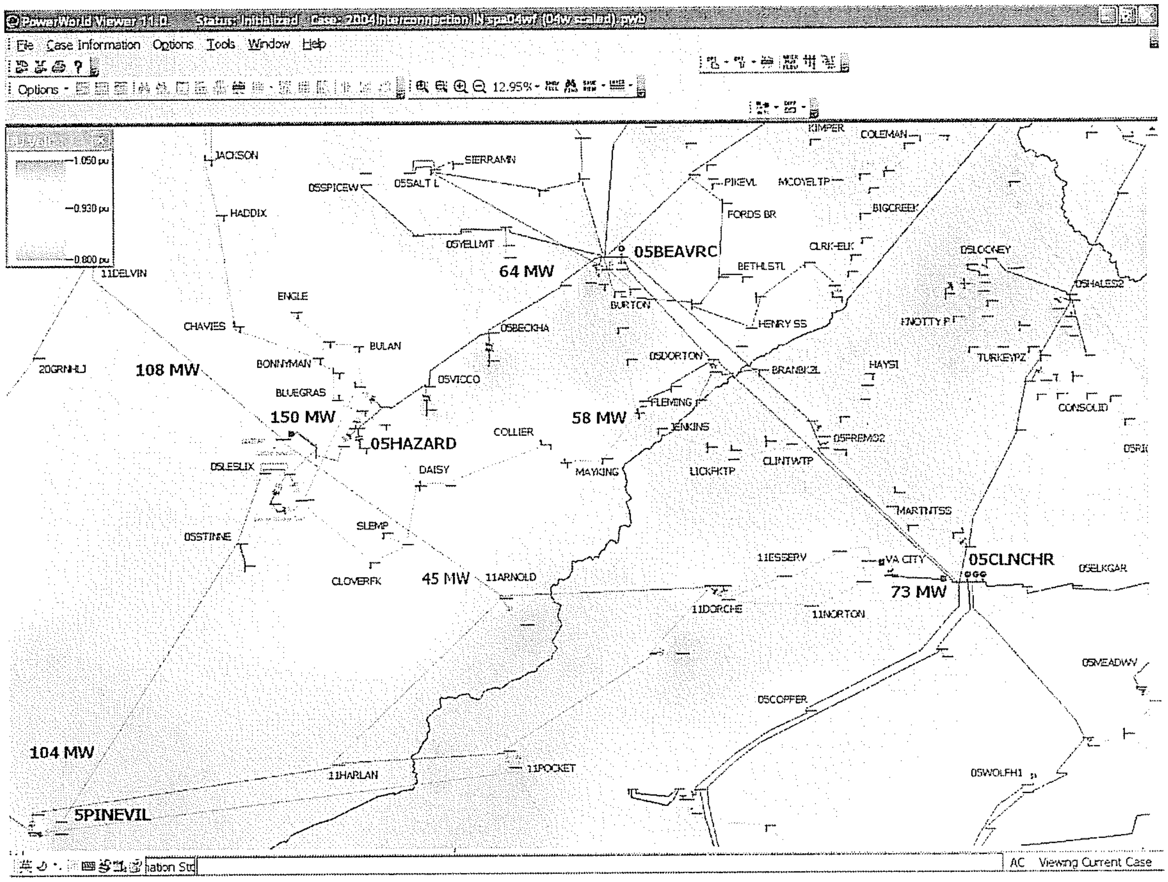


Figure A-2 Line Flows and Voltage Profile
2004 Winter Peak Normal Conditions with Wooten Interconnection

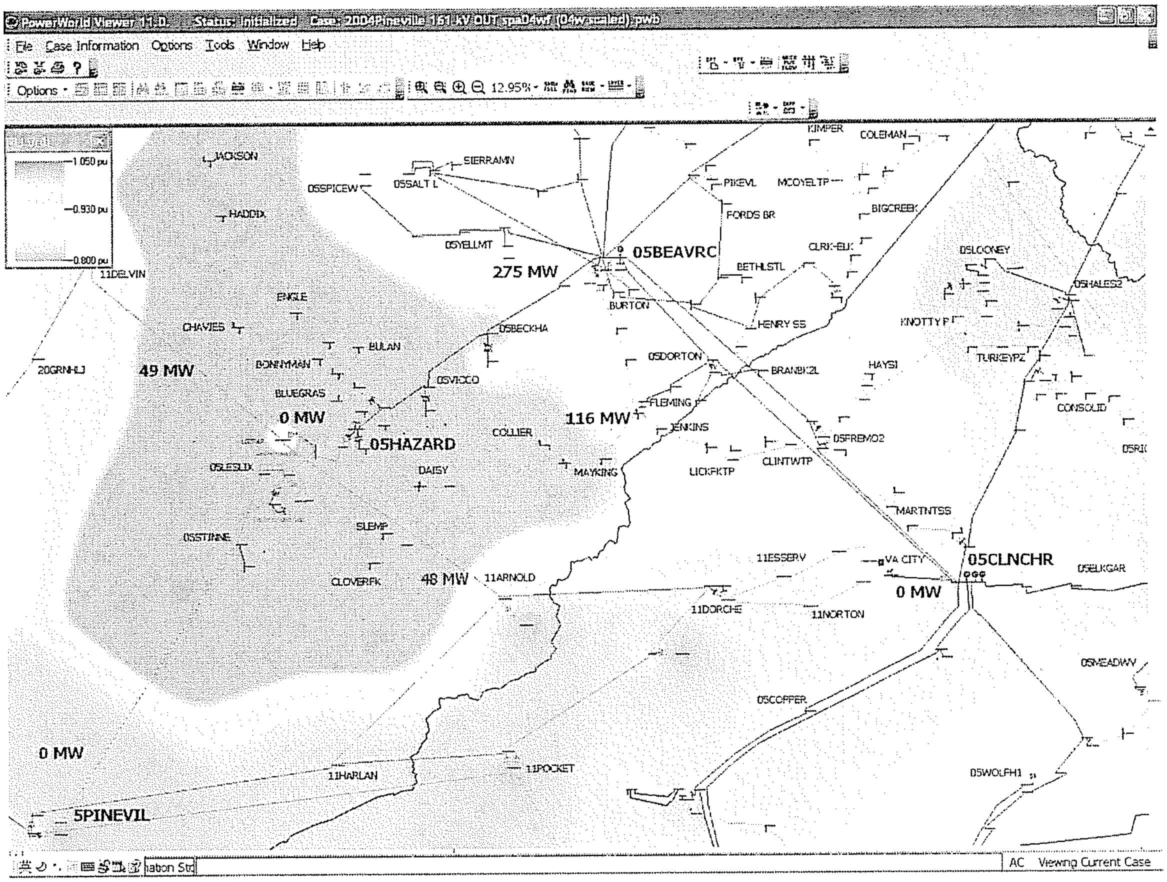


Figure A-3 Line Flows and Voltage Profile
2004 Winter Peak with Pineville – Hazard 161 kV Line Outage without Wooten Interconnection

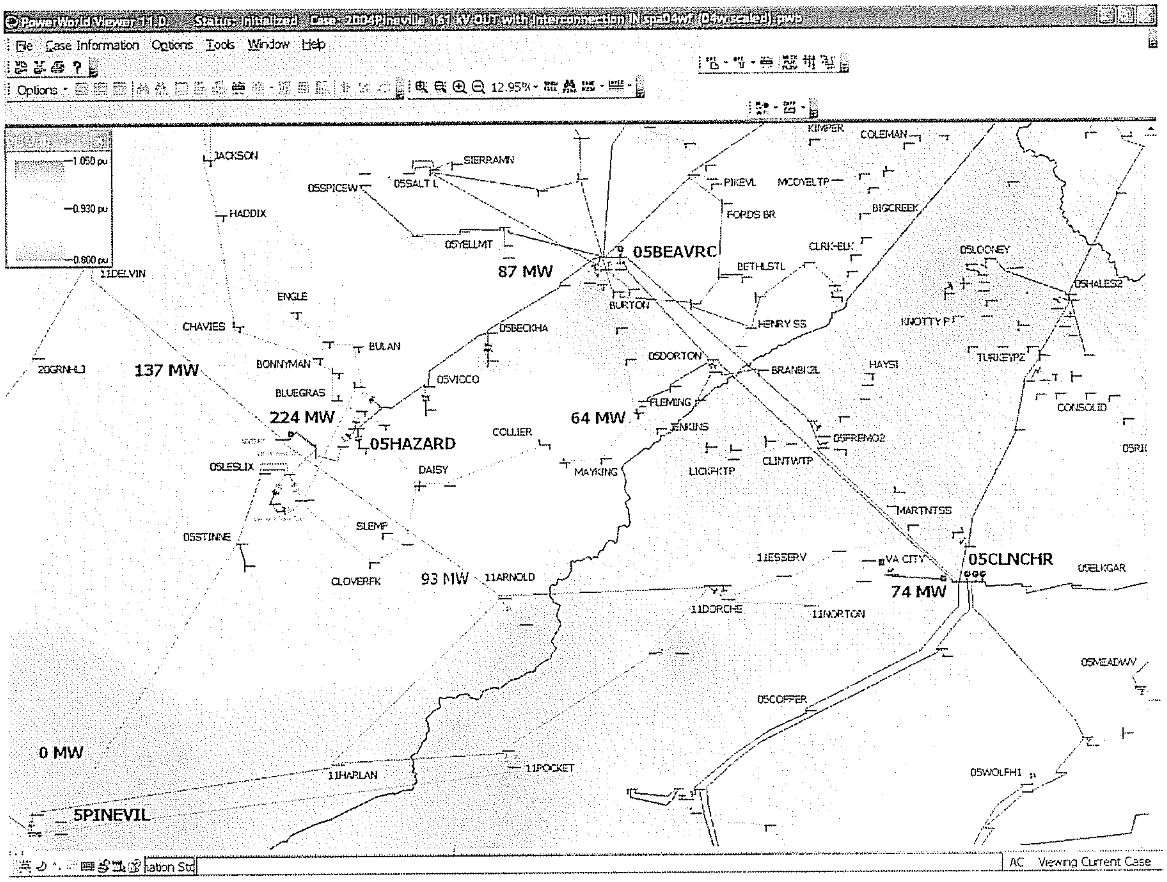


Figure A-4 Line Flows and Voltage Profile
2004 Winter Peak with Pineville – Hazard 161 kV Line Outage with Wooten Interconnection

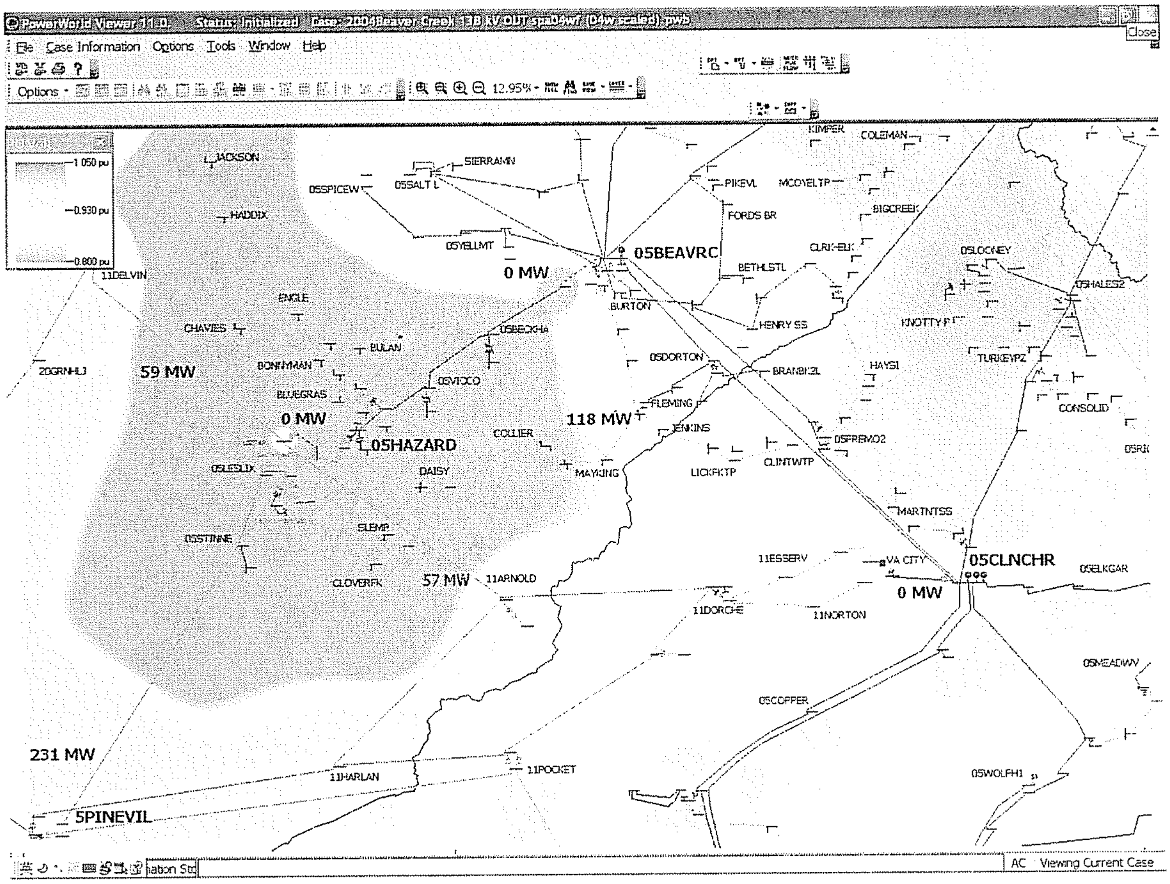


Figure A-5 Line Flows and Voltage Profile
2004 Winter Peak with Beaver Creek – Hazard 138 kV Line Outage without Wooten Interconnection

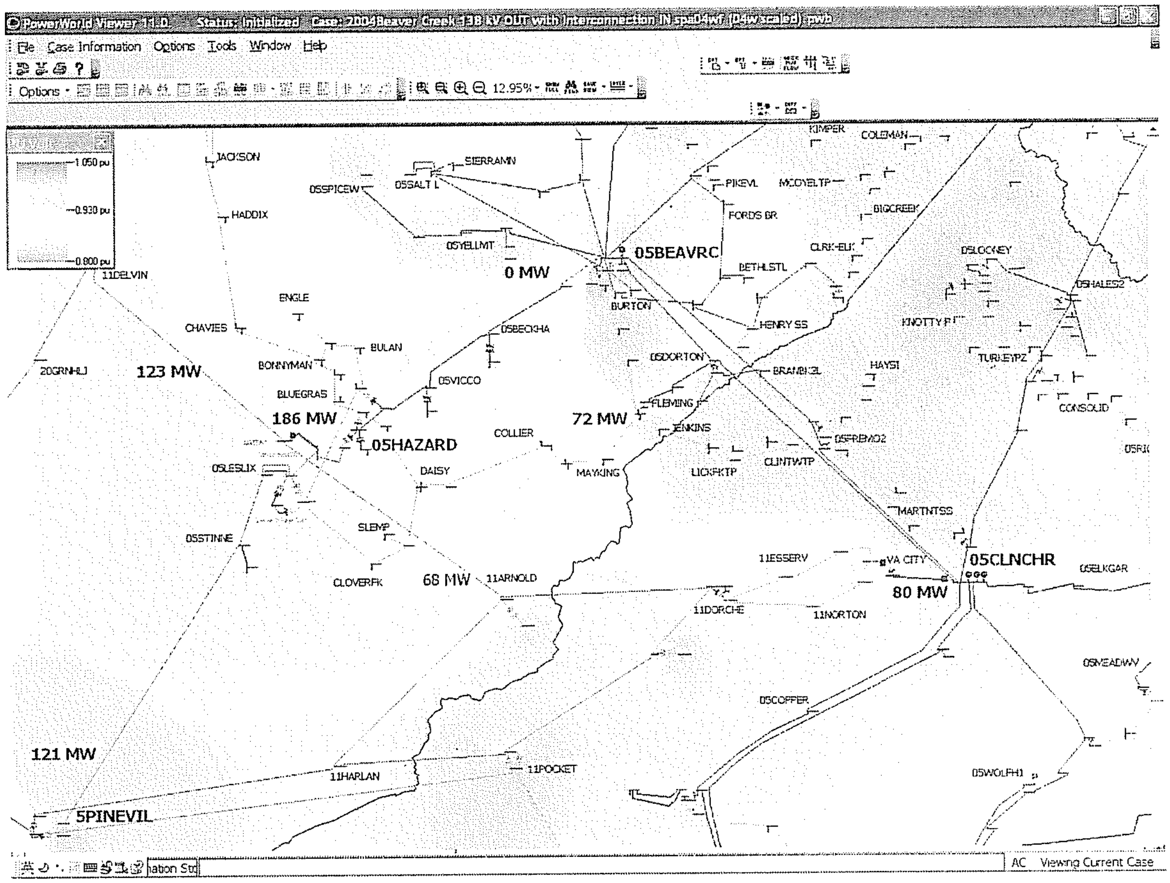


Figure A-6 Line Flows and Voltage Profile
2004 Winter Peak with Beaver Creek – Hazard 138 kV Line Outage with Wooten Interconnection

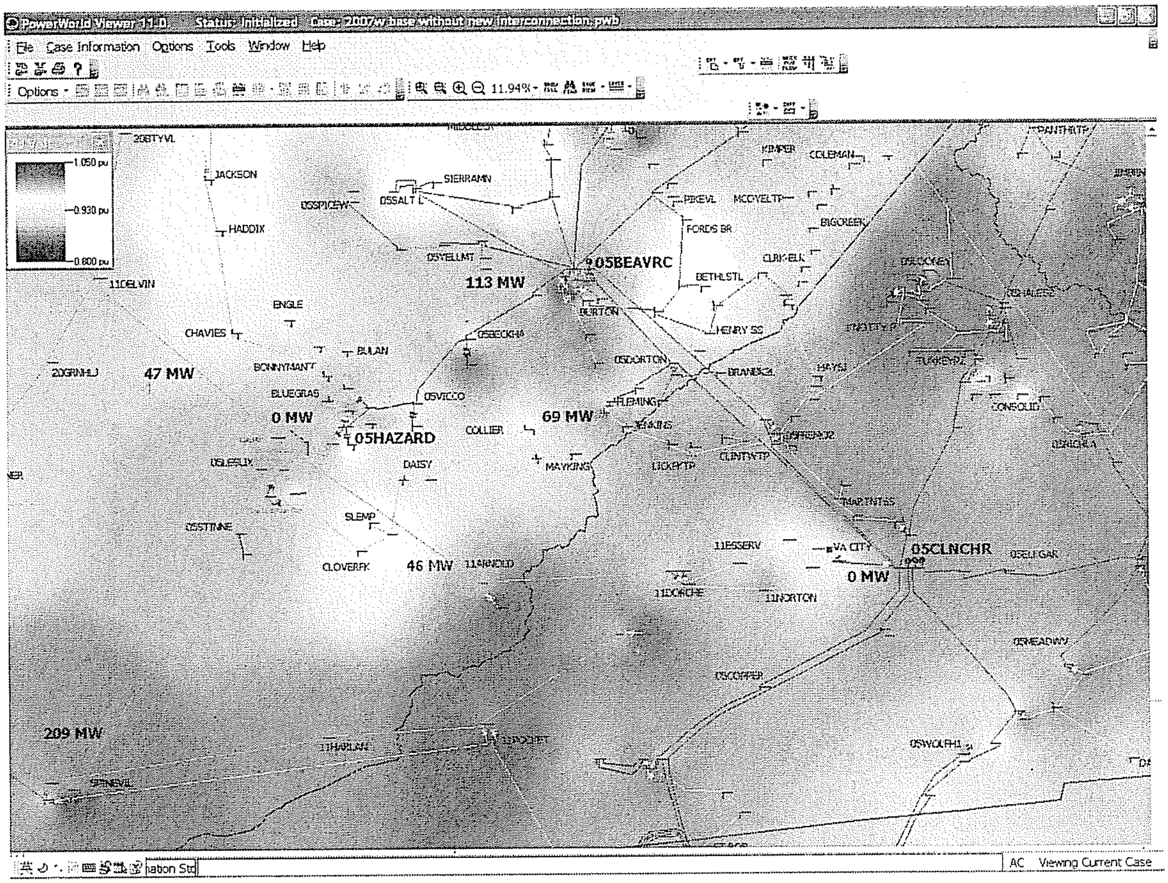


Figure A-7 Line Flows and Voltage Profile
2007 Winter Peak Normal Conditions without Wooten Interconnection

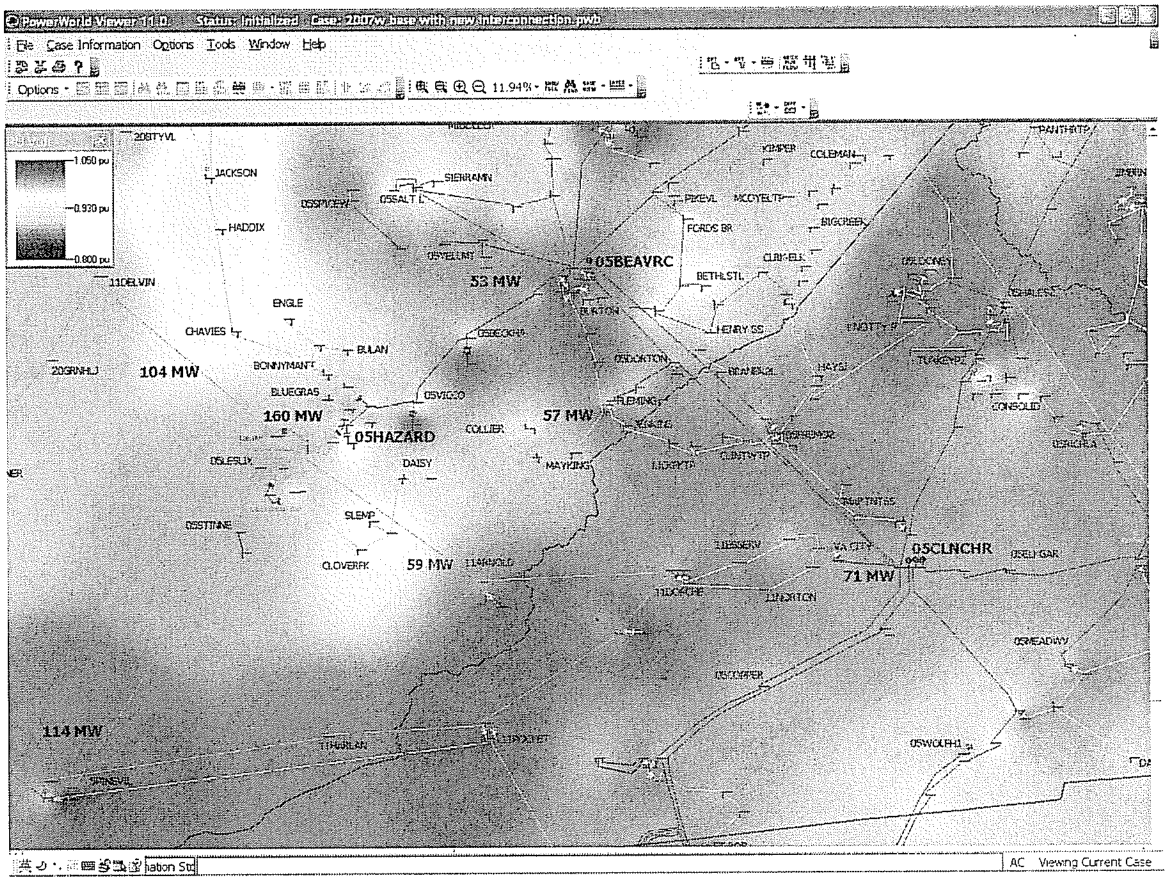


Figure A-8 Line Flows and Voltage Profile
2007 Winter Peak Normal Conditions with Wooten Interconnection

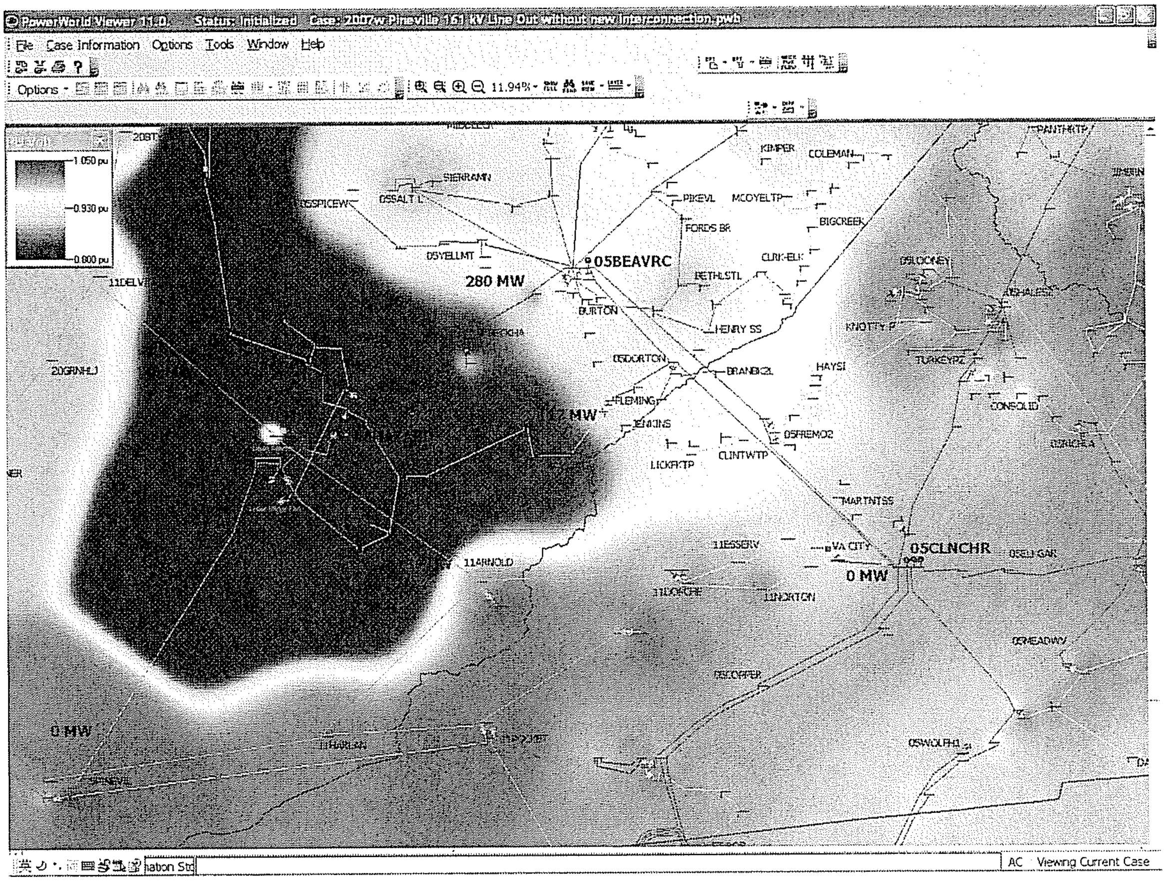


Figure A-9 Line Flows and Voltage Profile
2007 Winter Peak with Pineville – Hazard 161 kV Line Outage without Wooten Interconnection

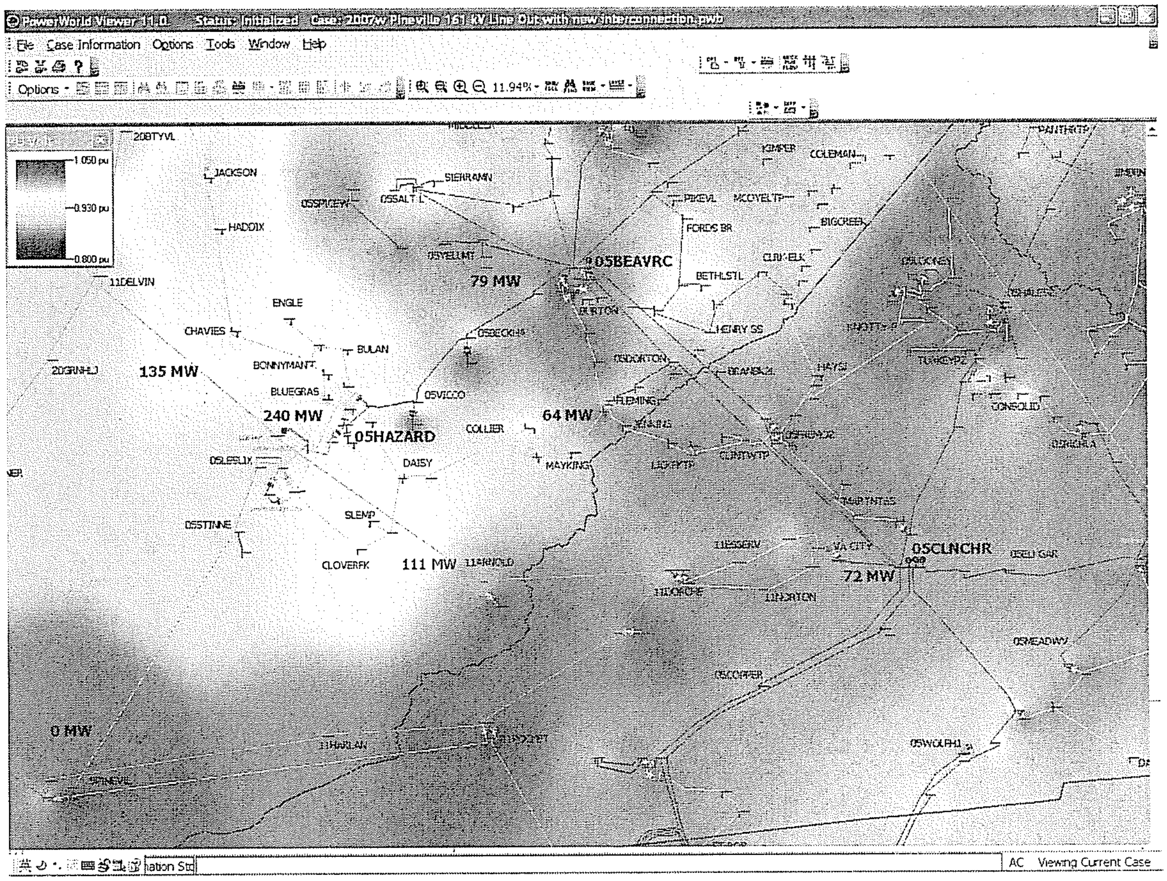


Figure A-10 Line Flows and Voltage Profile
2007 Winter Peak with Pineville – Hazard 161 kV Line Outage with Wooten Interconnection

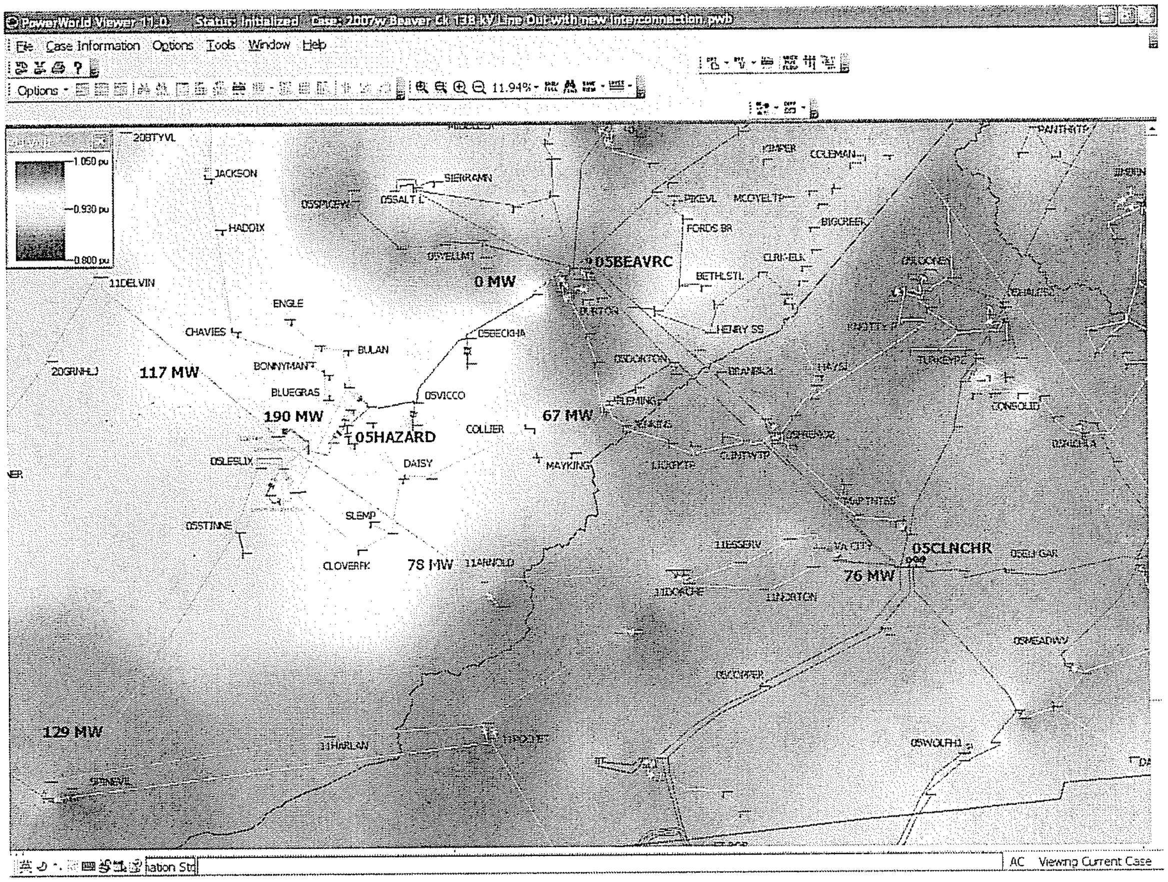


Figure A-11 Line Flows and Voltage Profile
2007 Winter Peak with Beaver Creek – Hazard 138 kV Line Outage with Wooten Interconnection