COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ASSESSMENT OF KENTUCKY'S ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION NEEDS	) ADMINISTRATIVE) CASE NO. 2005-00090)

O R D E R

On February 7, 2005, Governor Ernie Fletcher issued Executive Order 2005-121, which directed the Commission to report on the future needs for electricity in the Commonwealth. The report was to include a "Strategic Blueprint"[1] to "promote future investment in electric infrastructure in the Commonwealth of Kentucky, to protect Kentucky's low-cost electric advantage, to maintain affordable electricity rates for all Kentuckians and to preserve Kentucky's commitment to environmental protection."[2] The Executive Order directed the Commission to analyze the Commonwealth's projected needs for new electric generation, transmission and distribution, and to specifically review the following: the current status of generation, transmission and distribution facilities; available sources of electricity supply; projected demand through 2025; the existence of barriers to investment in generation, transmission and distribution; barriers to the utilization of technologies in generation, transmission and distribution; strategies for the utilization of technologies to improve the efficiency of electricity service; opportunities to promote utilization of renewable resources; and any

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[1] Executive Order 2005-121, February 7, 2005, at 2.

[2] Id.

other information to "help ensure future investment in electricity infrastructure to meet Kentucky's needs."[3]

In response to that Executive Order, the Commission initiated this proceeding by Order dated March 10, 2005, noting that it had addressed similar issues in 2001 in Administrative Case No. 387.[4] In addition, the Commission initiated a vulnerability assessment of Kentucky's electric transmission system following the electric blackout of August 14, 2003 and stated that the results of that assessment would be considered in preparing the report for the Governor.

All of Kentucky's jurisdictional electric utilities, generation and distribution, were made parties to this proceeding and directed to respond to an extensive data request. The municipal electric systems, the Tennessee Valley Authority ("TVA"), TVA distribution cooperatives, independent power producers, and other parties likely to have an interest in energy issues were invited to intervene and participate.

Intervening in this proceeding were the Attorney General of the Commonwealth of Kentucky ("AG"), Kentucky Industrial Utility Customers, Inc. ("KIUC"), Alcan Primary Products Corporation ("Alcan"), Century Aluminum of Kentucky, LLC ("Century"), and the Municipal Electric Power Association of Kentucky ("MEPAK"). Although TVA did not intervene, it filed on behalf of itself and its Kentucky distributors, information responsive to the Commission's data request and comments at a technical conference.

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[3] Id.

[4] Administrative Case No. 387, A Review of the Adequacy of Kentucky's Generation Capacity and Transmission System, Order dated December 20, 2001.

The vulnerability assessment was filed in the record of this case on April 28, 2005. All utilities that participated were ordered to certify that they have reviewed the assessment and taken appropriate action to address identified vulnerabilities. All such certifications have been received.

An initial data request was included as part of the Commission's March 10, 2005 Order and a second data request focused on limited issues with certain utilities was issued on April 28, 2005. In response to a motion filed by Alcan and Century, Big Rivers Electric Corporation ("Big Rivers") and Kenergy Corp. ("Kenergy") were ordered to respond to certain questions by Order issued May 27, 2005. All responses to data requests have been filed.

The Commission held a technical conference on June 14, 2005 for the purpose of receiving comments from utilities, intervenors, persons likely to be interested in energy issues, and the general public. Those that filed written comments and participated at the technical conference included Big Rivers, East Kentucky Power Cooperative, Inc., Kentucky Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, The Union Light, Heat and Power Company, Meade County Rural Electric Cooperative Corporation on behalf of the jurisdictional distribution cooperatives, Kentucky Pioneer Energy, MEPAK, PJM Interconnection, TVA, the Kentucky Resources Council, KIUC, Alcan and Century, the AG, the Environmental and Public Protection Cabinet, Energy Systems Group, LLC, Peabody Energy Corp., Moore Environmental, Geoff Young, and Dr. Donald G. Colliver. The Midwest Independent System Operator, Inc. also submitted written comments but did not otherwise participate at the technical conference.

The procedural schedule did not provide for briefs and all responses to data requests made at the technical conference have been filed.

The report required by the Executive Order, *Kentucky's Electric Infrastructure: Present and Future,* was submitted to Governor Fletcher on August 22, 2005 and is attached hereto as Appendix A. In accordance with the Executive Order, the report includes the Commission's appropriate conclusions and recommendations relative to Kentucky's future energy policy.

A "summary of proceedings," which summarizes the detailed information contained in the data responses and the filed comments of the participants, is attached hereto as Appendix B.

The Commission finds that this administrative case should be closed and removed from the docket.

IT IS THEREFORE ORDERED that Administrative Case No. 2005-00090 is closed.

Done at Frankfort, Kentucky, this 15th day of September, 2005.

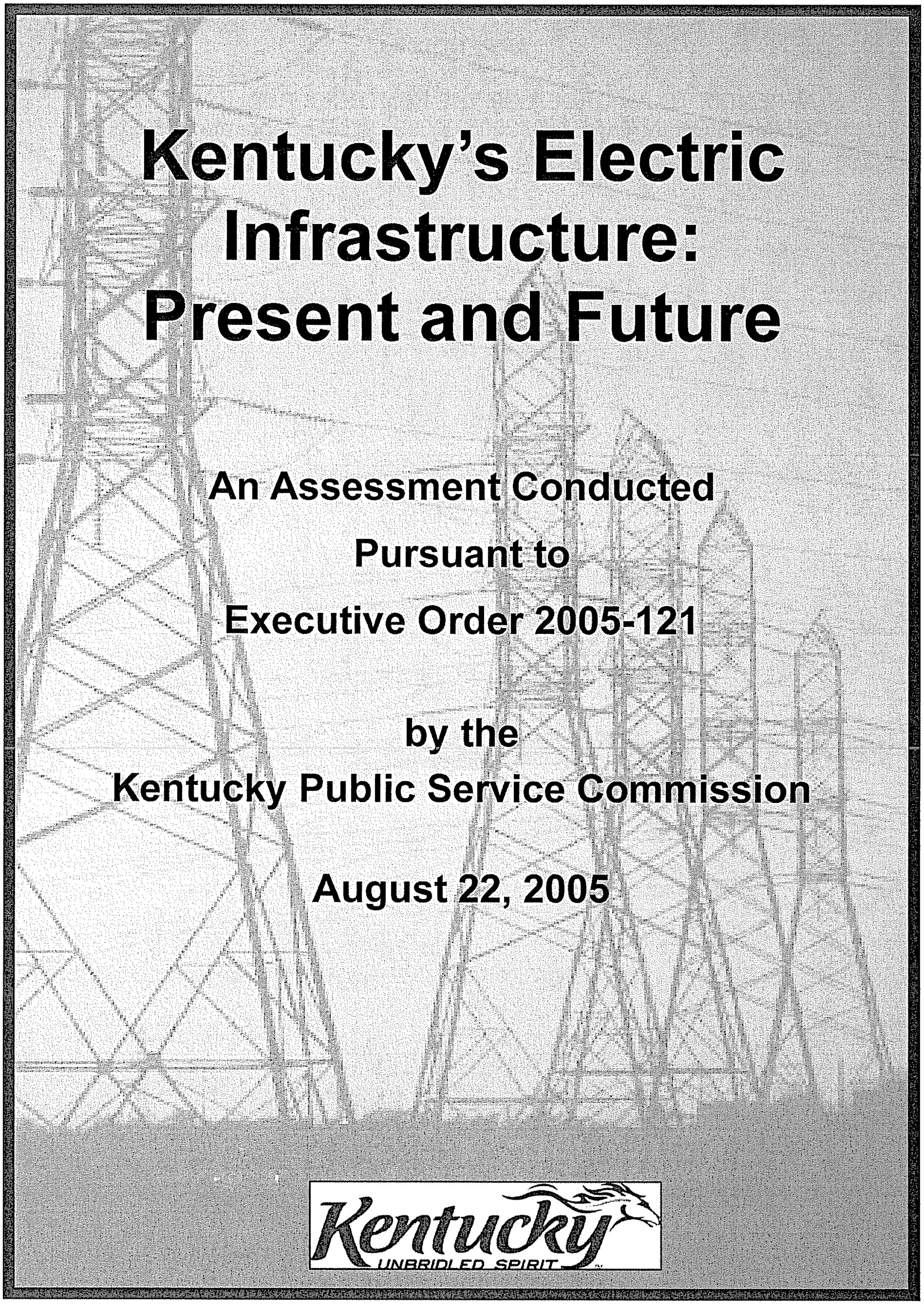
By the Commission

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2005-00090 DATED September 15, 2005



Kentucky's Electric Infrastructure: Present and Future

An Assessment Conducted

Pursuant to

Executive Order 2005-121

by the

Kentucky Public Service Commission

August 22, 2005

Kentucky
UNBRIDLED SPIRIT

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Participants

Alcan Primary Products Corporation
The Attorney General of the Commonwealth of Kentucky
Benton Electric System
Berea Municipal Utilities
Big Rivers Electric Corporation
Big Sandy RECC
Blue Grass Energy
Bowling Green Municipal Utilities
The City of Paris
Century Aluminum of Kentucky, LLC.
Clark Energy
Cumberland Valley Electric
Dr. Donald G. Colliver
East Kentucky Power Cooperative, Inc.
Electric Plant Board of the City of Vanceburg
Energy Systems Group, LLC.
Farmers RECC
Fleming-Mason Energy
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Meade County RECC
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Moore Environmental
The Municipal Electric Power Association of Kentucky
Nolin RECC
Owen Electric
Peabody Energy
Pennyrile Electric
PJM Interconnection
Princeton Electric Plant Board
Russellville Electric Plant Board
Salt River Electric
Shelby Energy
South Kentucky RECC
Taylor County RECC
The Tennessee Valley Authority
Tri-County EMC
The Union Light, Heat and Power Company
Warren RECC

The participant list includes the entities that responded to data requests, provided comments for the technical conference or both.

Executive Summary

This report was prepared in response to Executive Order 2005-121, issued on February 7, 2005 by Governor Ernie Fletcher, directing the Kentucky Public Service Commission (Commission) to report on the future needs for electricity in Kentucky.

The Executive Order called for a "Strategic Blueprint" to "promote future investment in electric infrastructure in Kentucky, to protect Kentucky's low-cost electric advantage, to maintain affordable electricity rates for all Kentuckians and to preserve Kentucky's commitment to environmental protection." The Commission was directed to identify projected needs for new electric generation, transmission and distribution; barriers to investment in electric infrastructure; barriers to the utilization of new technologies; opportunities to promote utilization of renewable resources; and other information necessary to "help ensure future investment in electricity infrastructure to meet Kentucky's needs."

In response, the PSC collected information and comments from Commission jurisdictional utilities, non-jurisdictional utilities, independent power producers, and those with an interest in energy policy. A list of participants is on page 4.

PRESERVING KENTUCKY'S LOW ELECTRIC RATES

Kentuckians pay the lowest electricity rates in the nation. In 2005, the average retail rate for electricity in Kentucky is 4.47 cents per kilowatt-hour (kWh), 40 percent below the national average rate of 7.52 cents/kWh. These low electricity prices have been a major factor in promoting economic development and growth.

Kentucky's low electricity rates are the result of investment by Kentucky's utilities in large, coal-fired generating units - which generate 95 percent of Kentucky's electricity - combined with an abundant local fuel supply, sound utility management and a statutory system that regulates the price jurisdictional utilities may charge for retail electricity

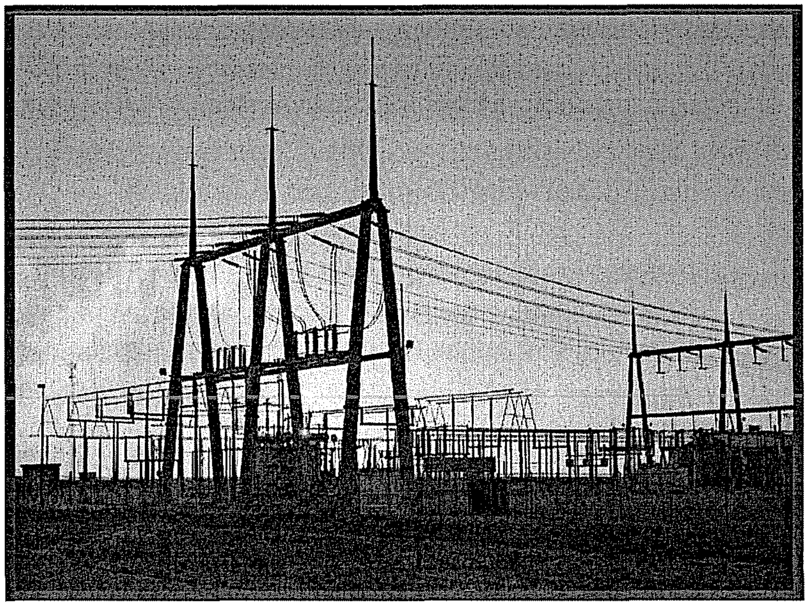
Kentucky and the United States as a whole have ample coal reserves. Coal will continue to supply the majority of the nation's electricity through 2025. But a number of uncertainties could affect Kentucky's long-term ability to ensure low electricity rates. These include federal policies regarding the development of regional electricity markets and air emission standards, factors affecting coal production and the price of coal.

The Commission is concerned that federal decisions and those of states that have moved away from traditional electric utility regulation may have negative impacts on Kentucky's transmission and generating facilities. As transmission requirements imposed from outside the state increasingly affect Kentucky, the Commonwealth is threatened with diminished control of a resource constructed for and paid for by Kentucky's electric customers.

KENTUCKY'S ELECTRIC INFRASTRUCTURE

Kentucky's jurisdictional electric utilities serve about 1.8 million customers. Thirty municipal electric systems and five distribution cooperatives supplied by the Tennessee Valley Authority are not subject to Commission jurisdiction. The non-jurisdictional electric utilities serve about 375,000 customers.

The Commission has determined that Kentucky's electric utilities, both jurisdictional and non-jurisdictional, have adequate generation infrastructure to serve their current customers and have demonstrated that they are adequately planning to serve the needs of their customers through 2025. Kentucky's peak electricity is expected to grow to an average rate of 1.7% requiring approximately 7,000 MW of additional generation by 2025 to maintain an adequate supply. It is also important to note all of the jurisdictional generating utilities currently rely on generation capacity that has been in operation for 35 years or more while none of the utilities indicated that they have plans to retire any of their older generating facilities, the Commission intends to require the jurisdictional utilities to address issues relating to their older generating units in their future planning.



Kentucky's electric transmission system is highly reliable to serve Kentucky customers. However, it is limited in the amount of power it can transfer through the state, particularly north and south.

Kentucky's electric transmission system is actually seven individual systems that are interconnected at numerous points throughout the state. The interconnections were initially intergraded to provide mutual reliability benefits, load diversity, and to reduce the occurrence of redundant facilities, but now are expected to transfer large blocks of power between utilities and states.

With the growth of the competitive wholesale market for electricity, the transmission system is now being called upon to provide interstate transfers – a purpose for which it was not designed. Power transfers from north of Kentucky to south of Kentucky, and vice versa, are limited due in part to the weak interconnection of the transmission systems.

While additional transmission interconnections are not needed for Kentucky's utilities to reliably and economically serve their customers, improving these interconnections may make it more feasible for Kentucky's utilities to increase off-system sales and for independent power producers to locate in Kentucky. There is much debate concerning how to allocate the costs of such improvements. Kentucky should remain engaged in this debate at the FERC and with the Regional Transmission Organizations (RTOs).

The Comprehensive Energy Bill signed into law by President Bush on August 8, 2005 contains provisions regarding the siting of the nation's bulk transmission grid. The provision may impact Kentucky's ability to regulate the siting of transmission lines within our borders.

The bill requires the Department of Energy to designate "national interest electric transmission corridors." Kentucky's location between northern and southern load centers, coupled with the constraints on north-south power transfers within Kentucky, present the possibility that one or more "national interest electric transmission corridors" through Kentucky will be identified. That designation will give the Federal Energy Regulatory Commission (FERC) siting jurisdiction for facilities within that corridor if the state does not act within one year. Kentucky should take steps to protect the interests of the Commonwealth in this process. Kentucky should also revisit its transmission siting statutes to ensure that they mesh with the energy bill provisions.

Ensuring reliability of retail service requires adequately maintaining distribution infrastructure, particularly managing vegetation in rights of way (ROW). Effective ROW management - cutting trees or branches which may come into contact with distribution lines - can reduce outages and restoration time during severe weather.

Kentucky has no regulations setting specific parameters for ROW maintenance. The jurisdictional utilities have expressed their opposition to such a standard, in large part because of the difficulties they encounter with property owner's desire to leave their trees undisturbed. The Commission recognizes these difficulties, but is concerned that the reluctance of some property owners to allow proper trimming of their trees lessens the reliability of entire distribution systems.

Establishment of an ROW clearance standards could provide utilities with the means to ensure proper maintenance and improve the reliability of electric service. Therefore, the Commission believes that further consideration should be given to the establishment of some practical distribution ROW clearing parameters for Kentucky's jurisdictional electric distribution utilities.

CONSERVATION, ENERGY EFFICIENCY AND ENVIRONMENTAL PROTECTION

As Kentucky's generating fleet ages, and as environmental requirements become more restrictive, energy conservation, the use of renewable energy sources, and alternative generation technology will play an increasingly important role in Kentucky.

Kentucky's jurisdictional utilities have established a number of demand-side management (DSM) programs to encourage energy conservation and defer the need to construct new generating capacity. However, because of relatively low electric rates, DSM has not yet proven to be as cost-effective in Kentucky as in other regions.

Several Kentucky electric utilities currently offer their customers the option of purchasing "green power," which is derived from renewable sources. However, due to the high cost to generate power from most renewable resources, "green power" is sold at a premium price. The Commission believes that it is important to encourage utilities to expand the use of renewables and reduce the cost of "green power". Kentucky's energy policy should include incentives to use renewable energy and an effort to educate the public regarding the benefits of renewables.

Financial incentives similar to those that may be developed for renewables should be available for coal gasification, which will enable the continued use of Kentucky coal while reducing the associated air emissions. Incentives could include tax credits, grants and low interest loans.

The Commission believes that Kentucky's environmental policy should be balanced. We encourage the electric utilities, state regulatory agencies and interested organizations to participate at the state and federal level to ensure that sound environmental policy is developed.

REGULATORY CONCERNS

In addition to concerns noted earlier, the Commission notes several regulatory issues affecting Kentucky's electric utilities.

At the state level, a change in tax policy has the potential to significantly impact all jurisdictional electric utilities. The Kentucky Revenue Department has begun subjecting distribution and substation transformers to sales tax. One utility noted that it has been assessed almost $2 million for the period from February 1, 2001 through November 30, 2004.

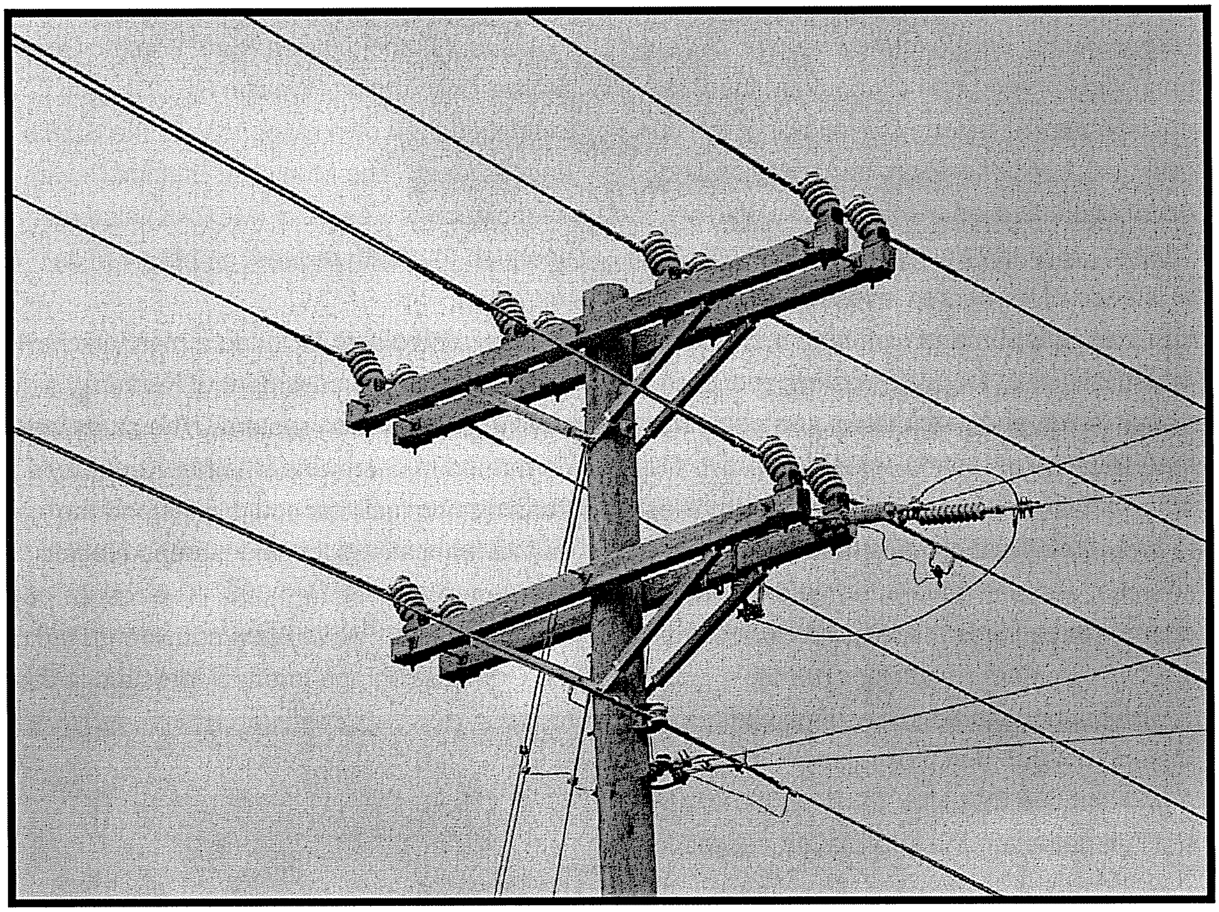
The increase in taxes assessed to regulated electric utilities will increase the cost to serve customers and will eventually result in higher rates. The Commission recognizes the responsibility of all citizens and companies to bear their fair share of Kentucky's tax burden. Therefore, the Commission recommends that this issue be considered in Kentucky's energy policy in the context of its overall impact on both electricity rates and taxes.

Federal energy policy has been moving toward a competitive market for electricity generation since the 1990's. RTOs now operate energy markets in addition to their initial role of operating transmission systems regionally. Several states have restructured their electric industry to a competitive model. Kentucky has not. Kentucky will be impacted by the federal legislation and federal actions. The Commission believes that its regulatory structure has enabled it to have the lowest cost power in the nation and that Kentucky should preserve its current statutory and regulatory framework, which focuses on the utilities' obligation to serve their customers within a defined service territory. Kentucky must insist on full participation in any federal decisions and work diligently to maintain its status as a low cost energy state.

The Commission recognizes that changes within the electric industry in recent years have increased uncertainty. However, the regulatory scheme in Kentucky has proven successful, due to the measured and deliberate approach that has been taken to address various issues. The Commission does not intend to suggest regulatory stagnation. Rather, in light of today's greater uncertainty, we believe it is our responsibility to seek ways to improve the existing regulatory framework.

Because the U.S. electric power industry is changing, Kentucky should consider policies to protect or insulate Kentucky ratepayers from market uncertainties and the price implications of future environmental restrictions. Given the economic benefits of Kentucky growing as an energy exporter, Kentucky policy makers should also give consideration to opportunities for Kentucky citizens, businesses, and communities to benefit from greater participation in energy markets. In either case, a balanced approach will be necessary to preserve Kentucky's low-cost energy, responsibly develop Kentucky's energy resources, and preserve Kentucky's commitment to environmental quality.

Among the immediate uncertainties facing the electric power industry in Kentucky are: federal policies regarding the development of regional electricity markets and air emission standards; the ability to site new electric generation and transmission facilities; factors affecting coal production and the price of coal; and technologies that will improve the efficiency of electricity production and use. Policy and technological developments with regard to these issues will directly affect electricity rates in Kentucky. Given the importance of low electricity rates for Kentucky, both as a tool for recruiting and retaining businesses, as equally as a necessity for all its citizens, the Commonwealth must continually evaluate its policies to mitigate the risks associated with generating, transmitting and distributing electricity.



Procedural Background

This report has been prepared pursuant to Executive Order 2005-121 issued on February 7, 2005 by Governor Ernie Fletcher. In that Executive Order, Governor Fletcher directed the Commission to report on the future needs for electricity in the Commonwealth. The report was to include a "Strategic Blueprint" to "promote future investment in electric infrastructure in the Commonwealth of Kentucky, to protect Kentucky's low-cost electric advantage, to maintain affordable electricity rates for all Kentuckians and to preserve Kentucky's commitment to environmental protection."

In the Executive Order's directive to analyze projected needs for new electric generation, transmission and distribution, the Commission was to include the following: the current status of generation, transmission and distribution; available sources of electricity supply; projected demands through 2025; the existence of barriers to investment in generation, transmission and distribution; barriers to the utilization of technologies in generation, transmission and distribution; strategies for the utilization of technologies to improve the efficiency of electricity service; opportunities to promote utilization of renewable resources; and any other information to "help ensure future investment in electricity infrastructure to meet Kentucky's needs."

In response to that Executive Order, on March 10, 2005, the Commission initiated Administrative Case No. 2005-00090 to assist it in gathering the information necessary to complete the report. All of Kentucky's jurisdictional electric utilities were made parties to this proceeding and directed to respond to an extensive data request from the Commission Staff. Notice of this proceeding was given to the non-jurisdictional electric utilities serving Kentucky customers, independent power producers with sites in Kentucky, and persons likely to have an interest in energy issues. The Tennessee Valley Authority (TVA) responded to Staff's data request on its behalf and on behalf of the five distribution cooperatives it currently serves. Three of those distribution cooperatives, Pennyrile Electric, Tri-County Electric Membership Corporation (Tri-County) and Warren Rural Electric Cooperative Corporation (Warren RECC), also submitted their own responses to the Staff's data request. The Municipal Electric Power Association of Kentucky (MEPAK) also responded to a data request on behalf of its members.

The record also included a highly technical vulnerability assessment of Kentucky's electric transmission system. The study was performed to determine whether Kentucky's transmission facilities could withstand the events that caused the widespread electric blackout of August 14, 2003. The results of that assessment have been considered by the Commission and briefly addressed in this report.

The Commission's Statutory Limitations

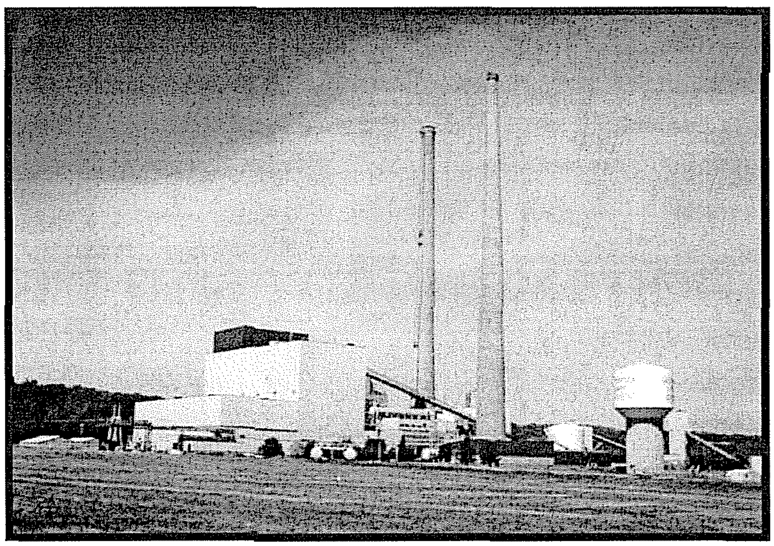
It is important to note that the scope of this proceeding and the report is responsive to the assessment required by the Governor's Executive Order but goes beyond the traditional duties of the Commission. The information provided by the participants has not been subject to the same scrutiny had the scope of this proceeding been focused solely on issues subject to Commission regulation. In that regard, we find no reason to doubt the accuracy of the factual information presented.

Even though the comments of some parties are diametrically opposite those of other parties, we have considered all comments in the development of this report. As set forth in the *Comprehensive Energy Strategy* and the Executive Order, this assessment is to serve as the "strategic blueprint" for policy makers. This report identifies and gives perspective to the issues that should be considered in developing a detailed, statewide energy policy.

Format of the Report

This report includes the conclusions and recommendations of the Commission as appropriate. The adequacy of Kentucky's generation, transmission and distribution resources is addressed first, followed by a discussion of the major issues facing the electric utility industry, the barriers they may face, the other issues identified in the Executive Order and other related issues that arose during the proceeding.

A "summary of the proceedings," which discusses the detailed information submitted in response to data requests and the comments of the participants has also been prepared. The "summary of proceedings" can be accessed at the Commission's Website at psc.ky.gov.



Introduction

Kentuckians, on average, pay the lowest electricity rates in the nation. According to U.S. Department of Energy (DOE) statistics for 2005, the average retail rate for electricity in Kentucky is 4.47 cents per kilowatt-hour (kWh), as compared to the national average rate of 7.52 cents per kWh. Over the past 15 years, only a few states in the Northwest (Idaho, Wyoming, Montana and Washington) and nearby West Virginia have been able to offer consumers and businesses electricity rates comparable to those available in Kentucky.

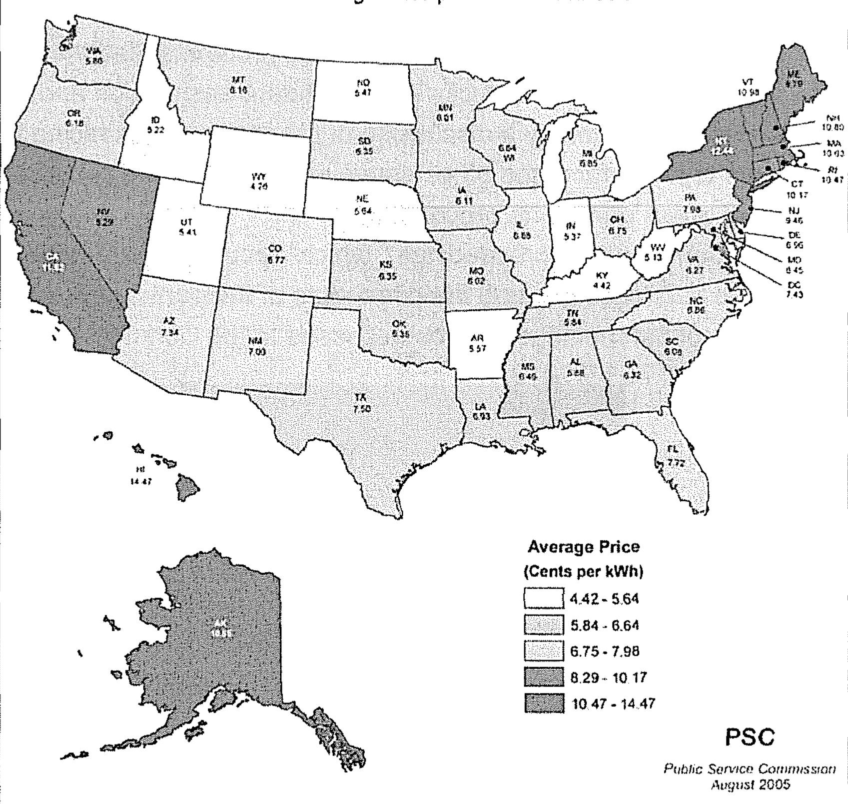
The reasons for Kentucky's low electricity rates, as compared to other states, are varied. Primarily, they result from historic investments by Kentucky's utilities in large, coal-fired generating units. Kentucky is among the top three coal producing states in the nation, and coal is used to produce approximately 95 percent of Kentucky's electricity. As a result of these historic investments, combined with an abundant local fuel supply, sound utility management and a statutory system that regulates the price jurisdictional utilities may charge for retail electricity, electricity prices in Kentucky are extremely competitive and favorable to economic development and growth.

Utilizing current technology and projected production rates, DOE estimates that the

Kentuckians, on average, pay the lowest electricity rates in the nation.

Average Retail Price Per Kilowatthour by State, 2003

U.S. Total Average Price per kWh is 7.42 Cents



Source: Energy Information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Data".

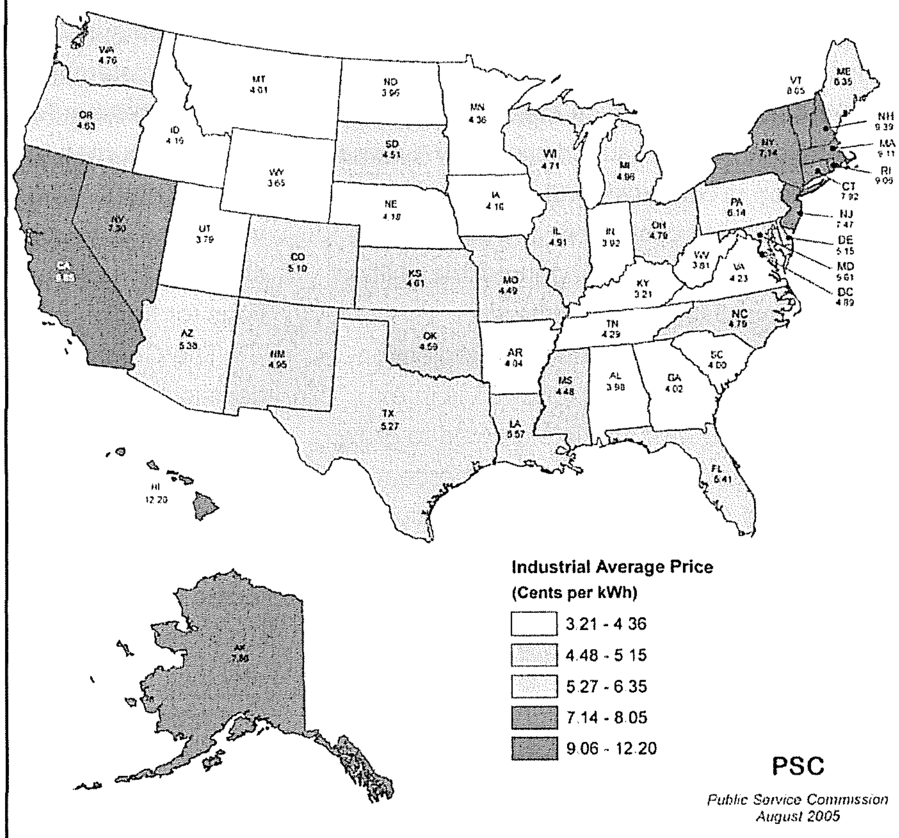
United States has a 250-year supply of coal to meet projected demand. Moreover, the United States is projected to continue to rely on coal to provide more than 50 percent of the nation's electricity through 2025. While this bodes well for Kentucky's near-term electricity price and supply, a number of uncertainties could affect Kentucky's long-term ability to ensure low electricity rates. These uncertainties pose a risk to Kentucky electricity consumers and will require policy makers to periodically evaluate Kentucky's regulatory model and long-term reliance on conventional coal-fired generation to meet electricity demand.

Among the immediate uncertainties facing the electric power industry in Kentucky are: federal policies regarding the development of regional electricity markets and air emission standards, factors affecting coal production and the price of coal, and technologies that will improve the efficiency of electricity production and use. Policy and technological developments with regard to these issues will directly affect electricity rates in Kentucky.

Given the importance of low electricity rates for Kentucky, not only as a necessity for all its citizens, but also as a tool for attracting and retaining businesses, the Commonwealth must continually evaluate its policies to mitigate, where possible, those factors that pose a risk to the ability of utilities in Kentucky to generate, transmit and distribute low-cost, reliable electricity.

U.S. Electric Power Industrial Average Retail Price per Kilowatthour by State, 2003

U.S. Industrial Average Price per kWh is 5.13 Cents



Source: Energy Information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Data".

Resource Adequacy– Generation

As discussed in more detail below, Kentucky has six major jurisdictional electric utilities that own or are in the process of acquiring generation. They include four investor-owned utilities: Kentucky Power Company (Kentucky Power); Kentucky Utilities Company (KU); Louisville Gas and Electric Company (LG&E); the Union Light, Heat and Power Company (ULH&P), and two generating and transmission cooperatives (G&Ts): Big Rivers Electric Corporation (Big Rivers) and East Kentucky Power Cooperative, Inc. (East Kentucky Power). Collectively, Kentucky's jurisdictional electric utilities serve about 1.8 million customers. There are also 30 municipal electric systems and five TVA supplied distribution cooperatives, which provide retail electric service that are not subject to the Commission's jurisdiction. TVA owns generation in Kentucky and serves a limited number of retail customers in western Kentucky. The non-jurisdictional electric utilities serve about 375,000 customers.

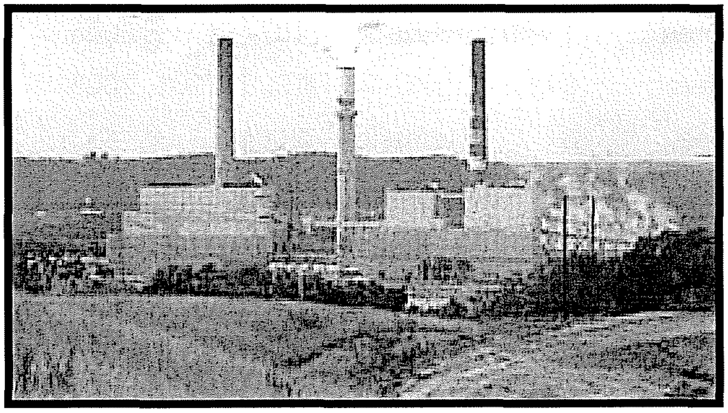
The peak electricity demand projection for Kentucky consumers for 2005 is in excess of 15,500 MW and is expected to grow at an average annual rate of 1.7 percent reaching 21,900 MW by 2025. As discussed later in this report, these projections take into account expected gains in energy efficiency. Approximately 7,000 MW of generation will need to be added over the next 20 years to meet this growing demand and maintain a reliable reserve margin. Presumably, the added generation will primarily be base load capacity with a small proportion being peaking capacity.

With regard to generation resource planning, Administrative Regulation 807 KAR 5:058 requires the six major jurisdictional electric utilities in the Commonwealth to file triennial integrated resource plans (IRPs) with the Commission, for review and evaluation by the Commission's Staff. The intent of the IRP process is to ensure that all reasonable options for the future supply of electricity are being considered, and that customers will be provided an adequate and reliable supply of electricity at the lowest reasonable cost.

The IRP process requires each major electric utility to forecast its customer demand and energy levels for a 15-year planning horizon, evaluate the adequacy of its generation supply and demand-side resources, determine the need for additional generating resources, and select the optimal mix of resources to meet the future needs of its customers. The Commission Staff reviews and critiques each of the six IRPs in a staff report, which provides recommendations for future IRP filings.

The Commission does not issue a formal decision on the adequacy of the IRPs, but since its inception in 1990, the IRP process has been very helpful in alerting the Commission to emerging issues and keeping the Commission apprised of the utilities' projected needs and future plans. As part of the Commission's monitoring and regulation of electric utilities, the IRP process is a helpful tool which the Commission expects will continue to provide benefits on a going-forward basis.

With respect to the non-jurisdictional electric utilities, they are not required to prepare formal IRPs. However, the record shows that they do perform similar planning studies. The models they utilize may have different names, but they are essentially the same. Also, the data inputs for the models are from the same or similar sources, and the output or results of their models are analyzed and reviewed by knowledgeable energy experts. In several instances, the planning for the non-jurisdictional utilities is performed by the same individuals that perform



these duties for the jurisdictional utilities.

The Commission has determined that Kentucky's electric utilities, both jurisdictional and non-jurisdictional, have adequate generation infrastructure to serve their current customers and have demonstrated that they are adequately planning to serve the needs of their customers through 2025. The jurisdictional utilities' long-range planning includes peaking generation, which consists primarily of gas-fired combustion turbines (CTs), and base load generation, which consists primarily of pulverized or fluidized bed coal-fired generation. To varying degrees, the jurisdictional utilities also include power purchases in their supply portfolios for serving their customers' future needs.

Although they are adequately planning to serve their customers' future needs, it is important to note all of the jurisdictional generating utilities own, or in the case of ULH&P, will soon own, generation capacity that has been in operation in excess of 35 years. While some of this generation has been operating for 40 to 50 years, none of the utilities indicated that they have plans to retire any of their older generating facilities, although several indicated that it is a possibility. The Commission does not fault the utilities for not having any plans for retirement of facilities that have been well maintained, upgraded and operated properly; however, we are mindful of the potential for failure of older units. Therefore, we will require that each of the jurisdictional generating utilities address issues relating to their older generating units in their next scheduled IRP filing.

(For Big Rivers, which no longer operates its generation, we will expect a summary overview of scheduled and unscheduled outages for all of the generation operated by Western Kentucky Energy (WKE) for the three most recent calendar years along with a summary of all environmental equipment that has been installed on each unit.)

A summary discussion of the information compiled on the generation and supply resources and planning and reserve requirements is provided in the discussion for each jurisdictional generating utility and for the non-jurisdictional electric utilities as a whole.

Tables listing the jurisdictional and non-jurisdictional generating units sited in Kentucky and a map showing the generating sites follow.

Electric Generation in Kentucky

Jurisdictional Generation

East Kentucky Power Cooperative, Inc.

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Dale	Clark	four	196	coal	1954-1960
Cooper	Pulaski	two	341	coal	1965, 1969
Spurlock	Mason	three	1,459	coal	1977, 1981, 2005
Smith CTs	Clark	seven	842	gas	1999, 2001, 2005
Bavarian Landfill	Boone	one	3	methane	2004
Green Valley Landfill	Greenup	one	2	methane	2004
Laurel Ridge Landfill	Laurel	one	3	methane	2004

Kentucky Power Company

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Big Sandy RECC	Lawrence	two	1,060	coal	1963, 1969

Kentucky Utilities Company

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Dix Dam	Garrard	three	24	hydro	1925
E.W. Brown	Mercer	three	697	coal	1957, 1963, 1971
E.W. Brown	Mercer	seven	849	gas	1994-2001
Ghent	Carroll	four	1,945	coal	1974-1984
Green River	Muhlenberg	two	163	coal	1954, 1959
Haefling	Fayette	three	36	gas	1970
Lock 7	Mercer	three	NA	hydro	1927
Tyrone	Woodford	two	58	oil	1947-1948
Tyrone	Woodford	one	71	coal	1953

Electric Generation in Kentucky

Jurisdictional Generation

Louisville Gas and Electric Company

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Cane Run	Jefferson	three	563	coal	1962-1969
Cane Run	Jefferson	one	14	gas	1968
Mill Creek	Jefferson	four	1,472	coal	1972-1982
Ohio Falls	Jefferson	eight	48	hydro	1928
Paddys Run	Jefferson	three	193	gas	1968, 2001
Trimble County	Trimble	one	383	coal	1990
Trimble County	Trimble	six	960	gas	2002, 2004
Waterside	Jefferson	two	22	gas	1964
Zorn	Jefferson	one	14	gas	1969

The Union Light, Heat & Power Company

Generating Station	County	No. Units	MW	Fuel	Initial Operation
East Bend	Boone	one	414	coal	1981

NOTE: ULH&P should close the transaction to acquire this generation later in 2005. The other generating units it will acquire are Miami Fort 6 and Woodsdale 1-6, which are located in Ohio.

Electric Generation in Kentucky

Non- Jurisdictional Generation

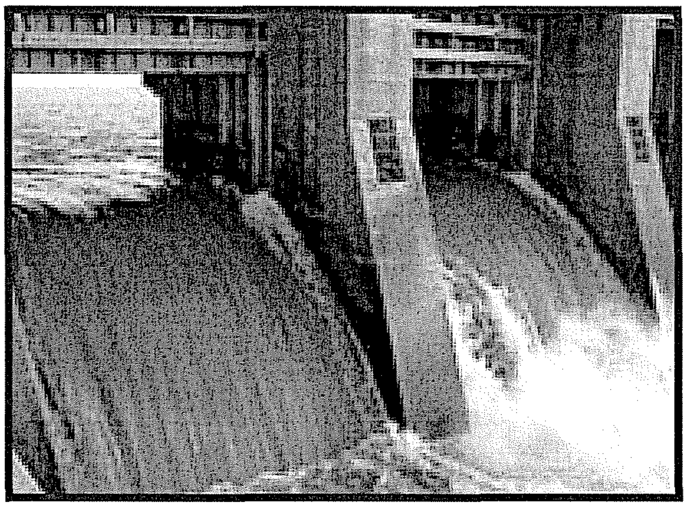
Municipal Generation

Generating Station	County	No. Units	MW	Fuel	Initial Operation
HMP&L – Station 1	Henderson	two	2	gas	1948
HMP&L – Station 1	Henderson	two	44	coal	1956, 1968
OMU – Smith Station	Daviess	two	425	coal	1964, 1974
City of Paris	Bourbon	seven	12	fuel oil	1934-1974

Federally-owned Generation

Tennessee Valley Authority

Generating Station	County	No. Units	MW	Fuel	Initial Operation
TVA - Paradise	Muhlenberg	three	2,331	coal	1963, 1970
TVA - Shawnee	McCracken	ten	2,611	coal	1953-1956
TVA – Kentucky Dam	Livingston	five	197	hydro	1944-1948
USACE – Laurel Dam	Laurel	one	70	hydro	1977
USACE – Barkley Dam	Lyon	four	130	hydro	1966
USACE – Wolf Creek Dam	Russell	six	270	hydro	1951-1952



Electric Generation in Kentucky

Non- Jurisdictional Generation

Merchant Generation

Dynegy

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Dynegy – Foothills	Lawrence	two	460	gas	2002
Dynegy - Riverside	Lawrence	three	690	gas	2001
Dynegy – Bluegrass	Oldham	three	624	gas	2002

Western Kentucky Energy

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Reid	Webster	one	65	coal	1966
Coleman	Hancock	three	455	coal	1969-1972
HMP&L Station 2	Webster	two	405	coal	1973-1974
Reid CT	Webster	one	65	fuel oil	1976
Green	Webster	two	454	coal	1979-1981
Wilson	Ohio	one	420	coal	1986

Cogeneration Generation

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Cinergy – Silver Grove	Campbell	one	20	gas	2001
Weyerhauser – Ky. Mills	Hancock	one	88	wood waste	2001
Cox – Waste to Energy	Taylor	one	4	wood waste	1995
Air Products – Calvert City	Marshall	one	27	gas	2000

Big Rivers - Resource Summary

Existing Generation/Supply Resources

Big Rivers is a not-for-profit G&T which provides power at wholesale to three member/owner distribution cooperatives, Jackson Purchase Energy Corporation (Jackson Purchase), Kenergy Corporation (Kenergy), and Meade County RECC. These distribution cooperatives provide retail electric service to approximately 107,000 customers in 22 western Kentucky counties. As part of an agreement arising from its 1996 bankruptcy filing, Big Rivers leases all of its generating facilities to WKE, an unregulated affiliate of LG&E and, in a companion transaction, purchases power from LG&E Energy Marketing, Inc. (LEM), another unregulated affiliate of LG&E, through 2022.

Big Rivers historically had the largest industrial load of any G&T because it supplied power to two aluminum smelters, Alcan Primary Products Corporation (Alcan) and Century Aluminum of Kentucky, LLC. (Century). However, as part of its reorganization, the smelters' firm loads are now supplied by LEM under separate power contracts with Kenergy. (*The issue of the continued provision of service to the smelters beyond the expiration of their contracts in 2010 and 2011 was raised by Alcan and Century in this proceeding and is discussed in the Rate Certainty, Cost Recovery and Other Regulatory Issues section.)*

Currently, Big Rivers has 597 megawatts (MW) available from LEM plus 178 MW available from the Southeast Power Administration (SEPA), through the U.S. Army Corps of Engineers, for a total of 775 MW. In 2012, Big Rivers' capacity will increase to 978 MW, with 800 MW available from LEM along with the 178 MW available from SEPA.

Resource Planning

Resource planning is integral to Big Rivers' overall planning processes. Like the other major jurisdictional utilities, Big Rivers files its IRPs with the Commission on a triennial basis. Big Rivers assists its three member/owner distribution cooperatives in determining their overall power requirements and combines those requirements to arrive at the Big Rivers system's annual load forecast for a 15-year planning horizon. Big Rivers determines the amount of supply resources required for each year. It compares these requirements with the resources available under existing, firm power supply contracts to assure sufficient power is available to meet its obligations to its members.

Big Rivers and its member distribution cooperatives screen Demand-Side Management (DSM) measures through cost/benefit analyses to determine acceptable DSM measures to initiate. Big Rivers provides financial participation (in the form of end-user incentive payments) and technical support to its distribution cooperatives for the following programs: (1) Add-on heat pump; (2) All Electric Touchstone Energy Home; and (3) Electric water heater. Not all Big Rivers' distribution cooperatives offer all programs. A detailed discussion of Big Rivers' DSM programs and the energy efficiency related services available to residential, commercial and industrial services through Jackson Purchase, Kenergy, and Meade County RECC is included in the Energy Efficiency, Demand-Side Management and Conservation section.

Big Rivers' budgets for the incentive programs are shown below:

2005	2006	2007 and beyond
$136,950	$174,250	$255,500

Resource Adequacy

As noted above, through 2011, Big Rivers will have 775 MW of generation available from LEM and SEPA. During this period, its base case forecast projects native load demand to reach 703 MW, while its high case demand forecast is 728 MW, either of which can be met under Big Rivers' power supply contracts. Beginning in 2012, Big Rivers will have 978 MW in generation available from LEM and SEPA. In 2017, the last year in Big Rivers' forecast horizon, its base case forecast projects native load demand to be 780 MW. Under its high case forecast, Big Rivers projects its native load demand in 2017 to be 829 MW. Again, these demands can be adequately met with the 978 MW Big Rivers will have available beginning in 2012.

Under its base case forecast, Big Rivers projects steady demand growth of 10 MW to 14 MW annually for the period 2005 through 2017, with average growth of 12.2 MW a year in its forecast. In its high case forecast, the annual average projected growth is 14.9 MW. Even under its high case forecast, Big Rivers' projected peak demand will not exceed the 775 MW contractual capacity that it has available from LEM and SEPA through 2011 or the 978 MW of contractual capacity available from the same sources through 2023, the last year of its contract with LEM. (*Although Executive Order 2005-121 calls for a review of resource adequacy through 2025, Big Rivers' most recent load forecast only extends through the year 2017. It should also be noted that Big Rivers' existing SEPA contract expires in 2016 and its LEM contract expires in 2023. This statement assumes its SEPA power contract will be extended beyond 2016.)*

Big Rivers has also included a minimum level of 50 MW of firm off-system sales per year, which it will also be able to meet with its contractual capacity.

Because it purchases 100 percent of its system power requirements under purchases that are considered "financially firm," with contracts that provide for liquated damages in the event of non-performance, Big Rivers does not have a formal planning reserve margin. Finally, Big Rivers has no plans to add base load or peaking capacity in the years from 2005 through 2017. Nor does it plan to retire any generating capacity during this period.

East Kentucky Power - Resource Summary

Existing Generation/Supply Resources

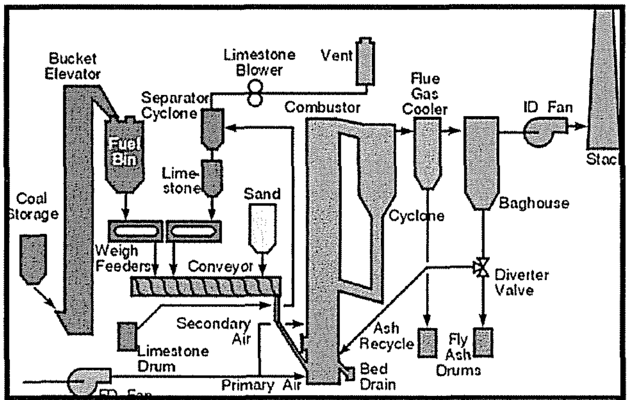
East Kentucky Power is a not-for-profit G&T utility which provides wholesale electric service to 16 member/owner distribution cooperatives in 89 counties throughout eastern and central Kentucky. Through these distribution cooperatives, it serves approximately 475,000 retail customers. In addition to its owned generation, which consists of 1,996 MW of coal-fired, base load capacity and 842 MW of natural gas-fired peaking capacity, East Kentucky Power has 170 MW of capacity available under a contract with SEPA.

Resource Planning

East Kentucky Power's planning cycle begins with its load forecast and consists of developing a capacity expansion plan and identifying potential financial impacts of implementing the plan. It develops a load forecast with input from all member systems every two years in accordance with Rural Utilities Service (RUS) requirements. It files an IRP every three years with the Commission. East Kentucky Power's evaluation of capacity needs is based on its latest load forecast, a capacity technology assessment, a screening analysis of capacity alternatives, including DSM, and a risk assessment of its expansion plan. The plan is simulated and input into East Kentucky Power's financial model to determine the impact on its margins and rates. The base plan is reviewed and reevaluated as necessary. A long-term financial forecast is developed annually which includes updated fuel costs and East Kentucky Power's base expansion plan with adjustments.

Capacity additions are generally made through a Request for Proposals (RFP) process in which East Kentucky Power exercises no control over the technologies bidders may offer. New technologies may be offered as self-build options if they are considered mature enough to be reliable. Circulating fluidized bed (CFB) boiler technology, such as the Gilbert Unit that became commercial in March 2005, is a relatively new technology for coal-fired generation. East Kentucky Power is presently planning to add at least two more coal-fired units using this same CFB technology.

Three years ago, East Kentucky Power began investigating the use of methane gas produced naturally at landfills to generate electricity. After completing an evaluation of the economics of these projects, East Kentucky Power constructed three landfill gas plants in 2003 and a fourth plant is planned for completion in late 2005. East Kentucky Power is studying methane recovery from certain industrial waste processes for electric generation. It is also studying wind as a potential renewable energy resource.



Circulating Fluidized Bed Combuster

In 2008, Warren RECC will become a member of East Kentucky Power and will receive wholesale power service. Following the issuance of an RFP and review of those proposals, East Kentucky Power applied to the Commission for a Certificate of Public Convenience and Necessity (CPCN) to construct a 278 MW CFB coal-fired unit at its Spurlock station to serve Warren RECC's load in 2008. That case is currently pending before the Commission. East Kentucky Power also has pending a second application for a CPCN to construct a 278 MW CFB coal-fired unit and five 90 MW combustion turbines at its J.K. Smith station with an in-service date of 2009. Projects identified by East Kentucky Power with in-service dates beyond 2009 are placeholders for future capacity additions. No commitments have yet been made for those projects.

East Kentucky Power's resource plan includes a significant number of gas-fired combustion turbines which are planned to meet peaking needs and some intermediate load needs. Forecasts of future fuel prices are also prepared and they are updated for use in preparing major power supply studies or the triennial IRP.

East Kentucky Power, in conjunction with its member distribution cooperatives, offers various DSM programs. The majority of these are residential. One non-jurisdictional program is non-residential interruptible rate pricing, which currently has 124 MW of interruptible demand. The DSM programs currently offered are discussed in detail in the Energy Efficiency, Demand-Side Management and Conservation section.

Resource Adequacy

East Kentucky Power's base case forecast projects a system peak demand of 2,633 MW in 2005 and a system peak demand of 5,158 MW in 2024. Its high case forecast projects peak demands of 3,028 MW and 5,861 MW in 2005 and 2024, respectively. Unlike many of the other major utilities in Kentucky, East Kentucky Power's system peak consistently occurs during the winter, rather than the summer.

East Kentucky Power uses a 12 percent target reserve margin, which, from a planning perspective, it meets during the summer with its owned generation and SEPA power purchases. However, it purchases blocks of firm power during the winter months to meet its reserve margin.

Kentucky Power - Resource Summary

Existing Generation/Supply Resources

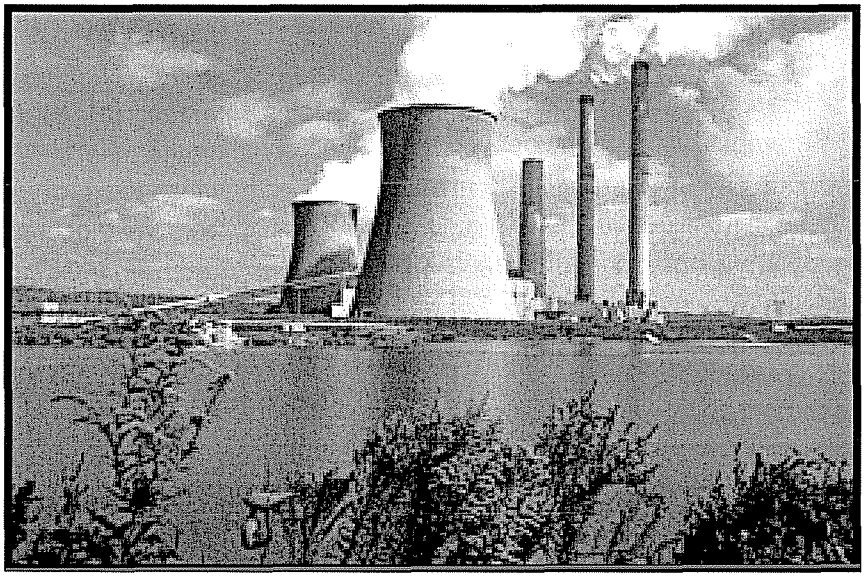
Kentucky Power, a subsidiary of American Electric Power Company, Inc. (AEP), a multi-state public utility holding company, serves approximately 175,000 customers in 20 counties in eastern Kentucky. Of its total available capacity of 1,450 MW, Kentucky Power owns 1,060 MW of coal-fired generation, and purchases the other 390 MW from an AEP affiliate under two unit power agreements. These unit power agreements, under which Kentucky Power purchases power from the Rockport Generating Station in southern Indiana, run through December 7, 2022.

AEP has nine subsidiaries that are operating utilities that provide electric service in 11 Midwest and South-Central states through the AEP-East and AEP-West power pools. Kentucky Power, along with four other AEP subsidiaries, is a member of the AEP-East power pool, and collectively they serve customers in seven states.

Resource Planning

Planning for Kentucky Power is performed by AEP, which conducts resource planning for the AEP-East power pool on a system-wide basis. AEP forecasts future customer demands and energy requirements, including committed sales to unaffiliated systems, and establishes a "target" which the system's resources must be able to serve with adequate reliability. It applies reliability or reserve criteria and determines how much reserve capacity is required to meet the requirements with a specified level of reliability. The result of this process is reduced to an equivalent reserve percentage based on more detailed analyses.

AEP reviews the adequacy of current and planned resources to meet the system's needs. This involves making a projection of the system's current and committed resources, taking into account anticipated capacity additions and retirements and currently scheduled purchases. This is then compared with its projected load requirements, taking into account reserve requirements to determine the need for additional resources. Any projected capacity deficiencies identified in this process indicate a need for additional resources. The pattern of such needs over time establishes the outline of required resource additions.



AEP reviews available future resource options including different types of supply-side resources such as new generation, generating unit ownership arrangements, power purchases, special opportunities, etc., as well as demand-side resources. AEP catalogs the various engineering, operational, and cost characteristics of each resource as part of determining the mix of resources that produces a low cost, reliable resource plan. AEP compares the total costs of owning and operating the system assuming different mixes of resource options, keeping in mind that flexibility in a capacity resource plan is a major advantage.

AEP monitors and revises all steps of the planning process on an ongoing basis, as appropriate. Updated estimates become available from time to time and are taken into account as practicable. Implementing the plan involves implementing feasibility analyses which may include additional analyses regarding the plan's financing requirements, specific ownership arrangements, etc. Once the plan is finalized, acquisition of the selected resources is arranged.

AEP is evaluating a mix of generation resources to meet the AEP-East power pool's projected capacity needs through 2015. AEP projects it may need additional capacity resources by 2006. Until then, capacity needs will probably be met through purchases from the market on an as-needed basis. Prior to 2015, AEP also expects to construct and/or acquire generation facilities in the AEP-East power pool, but the precise timing, technology mix, location, and size of such additions remain under review.

(AEP has researched and continues to evaluate integrated coal gasification combined cycle (CSS) technology. AEP is still considering whether to site an IGCC unit in Kentucky, Indiana or Ohio.)

DSM planning is generally performed at the same time as capacity resource planning but is performed on a utility specific basis. The evaluation process for DSM begins by establishing a DSM measure database, performing preliminary screening, and then analyzing the cost-benefit of the DSM measure. The DSM measures that pass the cost-benefit test are combined with supply-side models and the participant cost-benefit is analyzed. Finally, the DSM measures that pass those tests will be implemented with a follow-up review to verify performance.

Kentucky Power administers a formally approved DSM program under which it recovers costs via a DSM surcharge. Kentucky Power's DSM budget for 2005 is $678,250.

(DSM programs and DSM surcharges are discussed in detail in the Energy Efficiency, Demand-Side Management and Conservation section.)

<u>Resource Adequacy</u>

Kentucky Power's projected load and capacity, and the projections of load and capacity for the other members of the AEP-East power pool, indicate that Kentucky Power's obligation for additional capacity could be up to 500 MW by 2015. Kentucky Power's base case and high case demand forecasts include projected peak demands in excess of its available capacity in every year from 2005 through 2024. In the early years of this forecast period, Kentucky Power expects to meet its peak demand requirements with purchases of capacity from other members of the AEP-East power pool and occasional purchases in the wholesale market as it has done in recent years. However, Kentucky Power needs to purchase capacity for relatively few hours during the year.

The AEP-East power pool is now a member of PJM Interconnection (PJM), a regional transmission organization which has operational control of the AEP-East power pool's transmission system, and, therefore, Kentucky Power's transmission system. The AEP-East power pool is required to comply with PJM's reserve margin requirements. PJM has set the Installed Reserve Margin for the June 2005 through May 2006 planning period at 15.0 percent. Using current AEP reliability and diversity factors, this translates into an Installed Reserve Margin for AEP of 14.07 percent. This compares with a 12 percent margin that AEP used, based on its own determinations, from the late 1990s until joining PJM.

AEP has not established a fixed reserve margin for Kentucky Power. Kentucky Power is expected to provide its share of the AEP-East power pool's capacity on a proportionate basis, as opportunities arise. Within the next several years, Kentucky Power and AEP expect that new generation will be added by one or more members of the AEP-East power pool and that Kentucky Power will share in the ownership and cost responsibility, to some extent, of this new generation. Kentucky Power has no plans to retire any of its existing generating capacity, but may experience reductions in existing capacity if additional emission controls are required.

KU and LG&E - Resource Summary

Existing Generation/Supply Resources

KU provides electric service to approximately 485,000 customers in 77 counties throughout central, southeastern and western Kentucky. LG&E is a combination gas and electric utility serving approximately 389,000 customers in the greater Louisville - Jefferson County area and eight surrounding counties. KU and LG&E merged in 1998 but have retained their separate corporate identities. They are both subsidiaries of LG&E Energy LLC., a registered public utility holding company. While each utility owns its own generation, it is all jointly dispatched. All generation planning is also performed on a joint basis. In addition to their owned generation, KU and LG&E, through long-term contracts, have access to 200 MW of generating capacity from Electric Energy Inc. (EEI), 179 MW from Ohio Valley Electric Corporation (OVEC), and 195 MW from Owensboro Municipal Utility (OMU).

In addition to existing generation, KU and LG&E have jointly proposed to construct a 732 MW (summer rating) super-critical pulverized coal-fired base load generating unit at LG&E's Trimble County station (Trimble County No. 2). KU and LG&E will own 75 percent, or 549 MW, of the new unit. The Illinois Municipal Electric Agency (IMEA) and the Indiana Municipal Power Agency (IMPA), which own 25 percent of the Trimble County No. 1 coal-fired unit, intend to own 25 percent of Trimble County No. 2. Applications relating to the construction of Trimble County No. 2 are currently pending before the Commission and the Kentucky State Board on Electric Generation and Transmission Siting (Siting Board).

Resource Planning

KU and LG&E review planning alternatives and decisions annually as part of an ongoing resource planning process. Detailed resource planning is performed every three years as part of their joint IRP process. Demand and energy forecasts are prepared annually. In this integrated resource planning process, the economics and practicality of supply-side and demand-side options are examined to determine cost-effective responses to customers' needs. The steps undertaken in this process are: (1) establishment of a reserve margin criterion; (2) assessment of the adequacy of existing generating units and purchase power agreements; (3) assessment of potential purchased power market agreements; (4) assessment of demand-side options; (5) assessment of supply-side options; and (6) development of an economic plan from the available resource options. Screening of DSM options is also performed as part of this joint IRP process.

KU and LG&E have individually approved DSM programs with applicable DSM surcharges. A summary of the major existing DSM programs is included in the Energy Efficiency, Demand-Side Management and Conservation section. The DSM budget for each company through 2007 is as follows:

	2005	2006	2007
KU	$4,519,843	$4,642,473	$4,586,962
LG&E	$5,080,519	$5,223,187	$5,188,434

Resource Adequacy

KU's and LG&E's base case forecast projects a combined peak demand of 6,696 MW in 2005, growing to 8,794 MW by 2019. In their high case forecast, they project a combined peak demand of 6,748 MW in 2005 growing to 9,402 MW by 2019. In order to meet the growth projected in their base case forecast and maintain an adequate reserve margin, they plan to add approximately 2,100 MW of coal-fired base load capacity, 900 MW of natural gas-fired peaking capacity, and 180 MW of hydro capacity over the next 20 years.

The combined companies established an optimal reserve margin range in 2002 of 13 percent to 15 percent, with 14 percent recommended for planning purposes. The reserve margin analysis included in the KU and LG&E 2005 IRP recommends a range of 12 percent to 14 percent, while maintaining a 14 percent reserve margin for planning purposes.

KU and LG&E have no current plans to retire any existing generating units during the 2005 and 2025 period. However, KU and LG&E stated that some retirements are likely in the future due to the age of some units and the expected economics associated with future environmental compliance. KU and LG&E have over 1,300 MW of generation that is 35 years old or older.

ULH&P - Resource Summary

Existing Generation/Supply Resources

ULH&P, a wholly-owned subsidiary of the Cincinnati Gas & Electric Company (CG&E), is a combination gas and electric utility serving approximately 122,000 customers in five counties in northern Kentucky. CG&E is a wholly-owned subsidiary of Cinergy Corporation, a registered public utility holding company. ULH&P currently owns no generation. It has historically relied on CG&E to provide 100 percent of its power requirements via wholesale purchased power contracts. The current wholesale power contract expires at the end of 2006.

In response to the concerns expressed by the Commission in Administrative Case No. 387 regarding ULH&P's exposure to market- based prices for electricity, ULH&P proposed to acquire 1,105 MW of generating capacity from CG&E. The Commission initially approved the acquisition of the generating facilities on December 5, 2003 in Case No. 2003-00252. The transaction has received all other required approvals, except that of the Securities and Exchange Commission (SEC).

The transaction approved by the Commission also allows ULH&P to take power from CG&E when ULH&P's generation is not available; however, ULH&P will solicit bids for its back-up power supply needs and other parties will have an opportunity to beat the bid price offered by CG&E.

Resource Planning

Development of ULH&P's IRP involves two major processes, one organizational and one analytical. The organizational process involves the formation of an IRP team with representatives from key functional areas of Cinergy. The analytical process involves these steps: (1) develop planning objectives, assumptions and a load forecast; (2) screen potential demand-side resource options; (3) screen, and perform sensitivity analysis of the cost-effectiveness of potential supply-side resource options; (4) screen, and perform sensitivity analysis of the cost-effectiveness of potential environmental compliance options; (5) integrate the demand-side, supply-side and environmental compliance options; (6) perform final sensitivity analyses on the resource alternatives and select the plan; and (7) determine the best way to implement the chosen plan.

ULH&P's resource planning considers both demand-side and supply-side resources. On the demand-side, it intends to implement all cost-effective DSM programs, subject to the receipt of all necessary approvals. DSM programs are initially identified through a market potential analysis conducted by external consultants. All measures and programs so identified are evaluated for cost-effectiveness. As noted above, the load impacts of the recommended DSM programs are also included as a component in ULH&P's IRP.

ULH&P has a formally approved DSM program with an applicable DSM surcharge. ULH&P periodically files with the Commission for approval of new DSM programs or for the extension of existing DSM programs. A brief description of the DSM programs currently offered by ULH&P is included in the Energy Efficiency, Demand-Side Management and Conservation section. The annual budget for ULH&P's DSM programs is about $2.5 million.

New technologies are considered in Cinergy's generation planning processes. Subcritical and supercritical pulverized coal units, fluidized bed units, advanced CTs and combined cycle units, fuel cells, wind turbines, solar, biomass, and storage units are all considered. None of these new technologies have been implemented on a large scale commercial basis. Cinergy is currently involved in a detailed study with GE and Bechtel concerning the potential construction of an integrated gasification combined cycle (IGCC) unit.

Resource Adequacy

ULH&P's base case load forecast projects peak demands of 914 MW in 2005 and 1,116 MW in 2025, respectively. Its high case forecast projects a peak demand of 917 MW in 2005 and 1,178 MW in 2025. ULH&P will be using a target reserve margin based on several components which have historically been used by CG&E. The components include: (1) operating reserve of 4 percent; (2) unscheduled outages - the greater of 8 percent or the loss of the largest generating unit; and (3) weather-induced load forecast uncertainty identified as 3 percent. Upon the acquisition of its new generation, ULH&P will have a target reserve margin of 16.2 percent, which will gradually decrease to a 15 percent level by 2020 as its load grows.

With a planning reserve margin of 15 to 16 percent, ULH&P projects that it will have no need for additional capacity until 2013. Since the first capacity addition after 2005 is not expected until 2013, and since it has no plans for the retirement of East Bend 2, Miami Fort 6, or Woodsdale 1-6, ULH&P indicates that its long-term capacity needs will continue to be reassessed on a going forward basis.

Purchases from the wholesale market may be used to meet its reserve margin criteria during peak demand times in years prior to when it adds additional capacity.

Non-Jurisdictional Electric Utilities Resource Summary

(Not all non-jurisdictional systems provided information in this proceeding. The Commission has attempted to verify all information.)

Electric service is also supplied to parts of Kentucky by 30 municipal electric systems, TVA, and five TVA supplied distribution cooperatives. None of these suppliers are regulated by the Commission. Two of the municipal systems, Henderson Municipal Power and Light (HMP&L) and Owensboro Municipal Utilities (OMU), own their own generating facilities.

(The city of Paris owns 7 diesel generating units with a total capacity of 12 MW used for peaking purposes. Its supplier, KU, can call upon the use of this generation for up to 200 hours per year.)

HMP&L's generation is operated and managed by WKE, a non-regulated affiliate of LG&E, pursuant to a lease agreement with Big Rivers. OMU operates its own facilities but the power in excess of OMU's needs is provided to KU and LG&E pursuant to a power purchase agreement. The rest of the municipal systems purchase power from TVA, KU, Kentucky Power or CG&E.

The 13 municipal systems supplied by TVA are typically served under indefinite term full-requirements contracts that can be terminated by either party upon five years' notice. According to the information provided in this proceeding, two systems, Glasgow and Princeton have given such notice. Paducah's contract expires in 2009. The 12 municipal systems supplied by KU have full-requirements contracts with five-year cancellation notices, with the exception of Berea whose contract has a three-year cancellation notice. The two systems supplied by Kentucky Power have contracts continuing through the end of 2005. One system is supplied by CG&E.

Warren RECC gave its five-year notice to TVA in 2003. In 2008, it plans to become a member of East Kentucky Power.

The 28 municipal systems that purchase all or some of their generation and the RECCs that purchase their power from TVA are shown in the chart on the following page.

<u>Resource Planning</u>

Resource planning for a large majority of the non-jurisdictional electric systems is performed by their wholesale power suppliers. However, some systems perform their own planning function. In addition, some systems utilize the service of an external consulting firm to perform their planning.

<u>Resource Adequacy</u>

As noted previously, Kentucky's non-jurisdictional electric utilities tend to be primarily distribution systems served by either TVA, with no independent regulatory oversight, or by KU, Kentucky Power or CG&E pursuant to wholesale power agreements under the Federal Energy Regulatory Commission's (FERC) jurisdiction. As their non-jurisdictional status would imply, the Commission maintains little information on these utilities on a regular basis. However, the information provided in this proceeding indicates that these utilities, in conjunction with their wholesale power suppliers, have made and are making provisions for supplying their customers in the future. It should also be noted that, historically, KU and Kentucky Power have included the supply of wholesale power to the municipal systems they serve as part of their IRP filings with the Commission.

TVA supplied municipal systems

- Benton Electric System
- Glasgow Electric Plant Board
- Fulton Electric System
- Jellico Electric & Water System
- Monticello Electric Plant Board
- Paducah Power System
- Russellville Electric Plant Board
- Bowling Green Municipal Utilities
- Franklin Electric Plant Board
- Hopkinsville Electric System
- Mayfield Electric & Water System
- Murray Electric System
- Princeton Electric Plant Board

KU supplied municipal systems

- Barbourville Utility Commission
- Bardwell
- Berea Municipal Utilities
- Falmouth
- Madisonville Municipal Utilities
- Paris
- Bardstown Municipal Utilities
- Benham
- Corbin Utilities Commission
- Frankfort Electric and Water Plant Board
- Nicholasville City Utilities
- Providence

Kentucky Power supplied municipal systems

- Electric Plant Board of the City of Vanceburg
- Olive Hill Electric Company

Cinergy supplied municipal system

- Williamstown Utility Company

TVA supplied electric cooperatives

- Hickman-Fulton Counties Rural Electric Cooperative Corporation
- Pennyrile Electric
- Tri-County
- Warren RECC
- West Kentucky Rural Electric Cooperative Corporation

Merchant Plants

For the purpose of this report, merchant plants are defined as those electric generating facilities that are privately owned, sell the energy they produce into the wholesale market, and whose rates are not regulated by the Public Service Commission. WKE and Dynegy are currently the only operators of merchant plants in Kentucky. Together, they have a combined capacity of 3,218 MW at nine different sites. This represents about 23 percent of Kentucky's electric generation capacity.

WKE

The generation that WKE operates was built and is owned by Big Rivers. As previously noted, WKE operates this generation under a lease agreement with Big Rivers that runs through 2022. WKE is an affiliate of LG&E. Another LG&E affiliate, LEM, currently is obligated to sell 597 MW to Big Rivers and that obligation will increase to 800 MW in 2012. A table showing the Big Rivers' generation leased to WKE follows.

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Reid	Webster	one	65	coal	1966
Coleman	Hancock	three	455	coal	1969-1972
HMP&L Station 2	Webster	two	405	coal	1973-1974
Reid CT	Webster	one	65	fuel oil	1976
Green	Webster	two	454	coal	1979-1981
Wilson	Ohio	one	420	coal	1986

Dynegy

Dynegy owns the only merchant plants that were originally constructed for the primary purpose of selling power to the wholesale market. Dynegy owns eight natural gas fired turbines at 3 generation stations. Their combined capacity is 1,774 MW. The Dynegy generators were constructed in 2001 and 2002, when natural gas prices ranged around $3 to $4 per Mcf. Gas prices now are consistently over $6 per Mcf and are not forecast to decline in the foreseeable future. As we learned in Administrative Case No. 387, Dynegy's Bluegrass station has not operated in recent years. Dynegy's Foothills and Riverside generation has been operated only when gas prices made it economical to do so. A table showing the Dynegy generation located in Kentucky follows:

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Dynegy – Riverside	Lawrence	three	690	gas	2001
Dynegy – Foothills	Lawrence	two	460	gas	2002
Dynegy – Bluegrass	Oldham	three	624	gas	2002

Cogeneration

In addition to the merchant plants shown above, other non-utility generation in Kentucky operates as cogeneration facilities, meaning, generally, that it is industry-owned and operated by an entity whose primary business is not electric generation. A cogeneration facility typically uses an industrial waste product to generate electricity for use in the industry's manufacturing process. This electricity displaces the electricity that the cogenerator would otherwise purchase from the incumbent utility. If the cogenerator produces more electricity than is necessary to meet its needs, the excess is purchased by the utility at the utility's avoided cost. A table showing the cogenerating units located in Kentucky follows:

Generating Station	County	Units	MW	Fuel	Initial Operation
Cinergy – Silver Grove	Campbell	one	20	gas	2001
Weyerhauser – Ky. Mills	Hancock	one	88	wood waste	2001
Cox – Waste to Energy	Taylor	one	4	wood waste	1995
Air Products - Calvert City	Marshall	one	27	gas	2000

Kentucky Board on Electric Generation and Transmission Siting

In 2002 the General Assembly enacted legislation creating the Siting Board. The legislation requires that a merchant plant obtain a CPCN from the Siting Board prior to its construction. Since its inception, the Siting Board has received five applications to construct merchant generating facilities, all of which have been for base load generators. Four of the proposed merchant plants proposed utilizing coal; the other proposed using a mixture of coal and Refuse Derived Fuel as the major fuel source. Four of the applicants were granted conditional approval; one is pending with the Siting Board. The proposed merchant plants that have given notice to the Commission are shown below:

Company	Case No.	Date of Final Order	Results
Kentucky Mountain Power	2002-00149	9/5/2002	Conditional certificate
Thoroughbred Generating Co.	2002-00150	12/5/2003	Conditional certificate
Westlake Energy Corp.	2002-00171	4/14/2005	Withdrawn
Estill County Energy Partners	2002-00172	10/12/2004	Conditional certificate
Kentucky Pioneer Energy	2002-00312	11/10/2003	Conditional certificate
DTE Wickliffe	2005-00108	4/13/2005	Withdrawn
IMEA & IMPA	2005-00152	Pending	Pending

The Illinois Municipal Electric Agency and Indiana Municipal Power Agency filed Case No. 2005-00152 requesting a construction certificate for their purchase of 25 percent of KU's and LG&E's 732 MW Trimble County Unit 2. The remaining 75 percent of the unit will be non-merchant and jurisdictional.

In its comments, Kentucky Pioneer Energy (Kentucky Pioneer) expressed several concerns relating to the new Siting Board legislation that it found as barriers to investment. The two most significant related to the application of the legislation and the lack of a level playing field between merchant plants and regulated utilities.

Merchant Plant Economics

Generally, the decision to build a merchant generator in today's post-Enron financial climate entails significant risk. Because merchant generators operate competitively, in a cost minimizing environment, and have no guarantee of cost recovery as a cost-of-service regulated utility does, and because construction of a generator is very capital intensive, they often have difficulty obtaining financing.

To be viable merchant generators must exploit their market advantages and may do so in a number of ways. In order to minimize costs, some merchant plants are sited in a location as to minimize fuel cost, either near a natural gas pipeline or near a coal supply. Some plants use a fuel source that is less expensive or whose use is subsidized, such as waste coal, or municipal waste. Other plants may locate their generation close to a load where transmission constraints diminish the ability for bulk power imports to that load, thus giving themselves a market advantage in that area.

In addition to minimizing cost, it is also necessary to minimize uncertainty, especially in order to acquire financing. Some merchant plants enter into long-term contracts to supply needed base load capacity to an end-user, such as a regulated electric utility, a municipality, or even an industrial park or electricity intensive end-user (in states that have restructured). The low cost rates of Kentucky's electric utilities add an additional barrier to obtaining financing because of the difficulty that merchant plants have in obtaining Kentucky's regulated utilities as customers since they must compete with the regulated utilities self-construct alternatives.

Finally, merchant generators may also seek to enter agreements with regional market operators to commit all or some of their resources to that regional market as the operator seeks to increase regional reliability. How this installed capacity is to be compensated is being debated by regional market operators including both PJM and the Midwest Independent System Operator, Inc. (MISO).

In Kentucky, the merchant plant proposals have fit the scenarios mentioned above. Plants have been proposed near a fuel supply, with peaking units near the natural gas pipelines, and coal-fired units near the "mine-mouth" or on abandoned mine sites thus ensuring an adequate coal supply while minimizing transportation cost of that coal. Proposed plants have also sought fuel supplies that were less expensive or subsidized, such as waste coal, or municipal solid waste. One element of the above scenarios that, to the knowledge of the Commission, has not been developed for merchant plants in Kentucky is the acquisition of long-term power supply contracts. That may be a contributing factor to the lack of merchant plant construction within the Commonwealth.

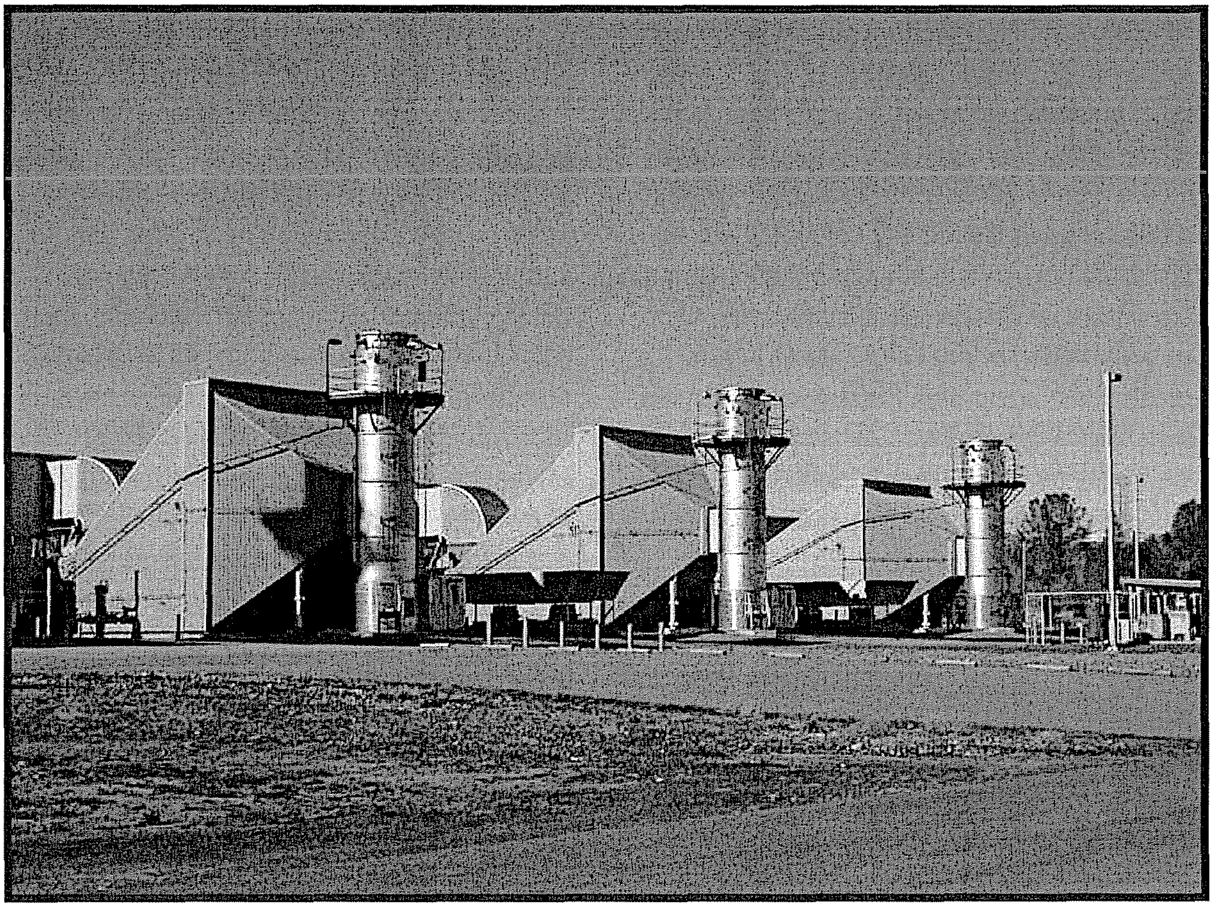
Merchant Power Sales to Regulated Utilities

Merchant plants may offer utilities a viable alternative to adding new regulated generation.

In response to the Commission's data requests, all six jurisdictional generating utilities indicated some reliance on short-term and long-term purchased power from the wholesale power market in which most merchant plants compete. In describing their resource development or acquisition processes, the jurisdictional generating utilities noted that they routinely request and evaluate competitive power supply offers in addition to evaluating the cost to self-construct. Kentucky's regulated utilities consider power supply bids submitted by merchant plants as part of their resource mix. However, as was found in Administrative Case No. 387, there is little evidence to suggest that merchant power at market prices will be below the cost-of-service rates of Kentucky's current electric customers.

Benefits of Merchant Plants

Peabody Energy advocates considering the economic benefits of electricity sales from merchant plants to other states, noting that 75 percent of the coal produced in Kentucky is used outside the state but also acknowledges that merchant plants face barriers to market entry. Peabody Energy urges Kentucky to address barriers to the financing and construction of merchant plants in the



state.

Peabody states that greater use of Kentucky coal to generate electricity would be beneficial to the coal industry. Merchant plants that generate electricity with Kentucky coal could benefit the state economically, regardless of where their output is sold. Peabody states that electricity should be viewed as any other Kentucky made product. However, as noted by Big Rivers, merchant plant generation of electricity will use a portion of the emissions allowances allocated to Kentucky, which could have negative consequences for regulated utilities and their customers,

Kentucky's future energy policy must strive to strike a balance between becoming a large scale energy exporter and protecting our status as having the lowest cost electricity in the nation.

Conclusions

Kentucky's future energy policy must strive to strike a balance between becoming a large scale energy exporter and protecting our status as having the lowest cost electricity in the nation. This is a difficult task with many factors to address that may have a significant impact on the electric utilities operating in Kentucky and our ability to attract merchant plants.

As Kentucky's current generating plants age or new environmental requirements are imposed, merchant generation may become feasible and attractive to our regulated electric utilities. And, considering that merchant plants that utilize Kentucky coal or coal waste can provide economic benefits beyond the generation of electricity, the need to balance the merchant issue becomes more important.

Another area which was addressed by recommendations in the *Comprehensive Energy Strategy* was clean coal technology. This may be an area where utilities, the merchant industry and the research community to form partnerships to help Kentucky become both a leader in this alternative technology and become a large scale energy exporter. The Comprehensive Energy Bill just passed by Congress authorizes the establishment of significant federal programs devoted to clean coal technology and provides additional incentives in the form of loan guarantees and investment tax credits. Kentucky must actively and aggressively pursue these funds if it wants to promote the development of clean coal technologies.

Resource Adequacy - Transmission

Electric Transmission Status

The electric transmission system in Kentucky serves two primary purposes. One is to enable electric utilities to provide adequate, reliable electricity to their consumers in Kentucky; the other is to accommodate economic bulk, wholesale power transfers. Those transfers can be entirely within Kentucky, exported from Kentucky, imported into Kentucky, or transferred through Kentucky. Each transmission provider defines "transmission" slightly differently, but they all generally consider transmission facilities to be those operating at 69 kV or higher, while distribution facilities are those operating below 69 kV. The Kentucky transmission system has demonstrated the ability to deliver power to Kentucky customers reliably. However, it is generally known that the system is limited in the amount of power it can transfer through the state, particularly north and south. New transmission projects will undoubtedly be responsive to meet Kentucky's future electricity needs. Similarly, new transmission may be required to ensure that Kentucky ratepayers benefit, and any negative effects are mitigated, from continued development of regional electricity markets.

Kentucky's electric transmission system is actually seven individual systems that are interconnected at numerous points throughout the state. These seven transmission systems are owned by five utilities regulated by the Commission, the TVA and CG&E.

(CG&E owns the transmission facilities located in northern Kentucky that are used to provide bulk power at wholesale to ULH&P.)

Transmission Miles by Voltage for Each Utility

Voltage	Kentucky Power	Big Rivers	CG&E	East Kentucky Power	KU and LG&E	TVA
69	417	791	126	1,864	2,581	4 32
138	299	15	104	388	1,172	
161	46	341		333	55	1,008
345	9	68	61	60	482	
500					36	85
765	258					
Total Miles:	**1,029**	**1,215**	**291**	**2,645**	**4,930**	**1,525**

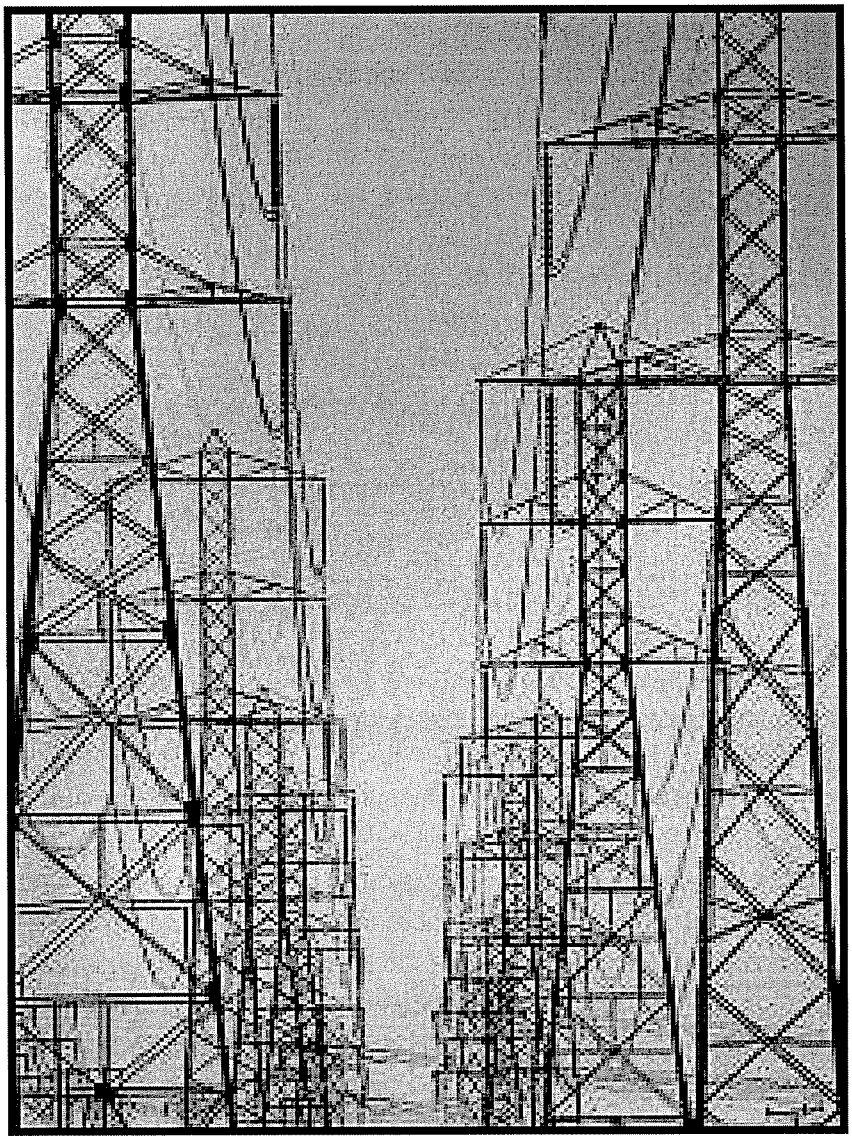
Numbers derived from the Public Service Commission's GIS database for Electric Transmission collected in 2001-2004.

Each of these systems was created to transfer power from its own generators to its own customers. Over time the systems became increasingly interconnected for mutual reliability benefits, load diversity, and to reduce the occurrence of redundant facilities. Since the individual transmission systems operate at different voltages, interconnection usually requires the construction of expensive transformers (substations) at each interconnection point. FERC generally regulates the transmission system with the state commissions having some limited authority.

<u>Adequacy to Serve its Kentucky Customers</u>

Each transmission provider in Kentucky has a history of providing adequate transmission service to its customers and has planning tools in place to ensure adequate system expansion and service in the future. Each uses reliability indices to measure system performance. All use System Average Interruption Duration Index (SAIDI) to measure the duration of service interruptions and another index to measure the frequency of interruptions.

The transmission providers also follow National Electric Reliability Council (NERC) transmission guidelines and those of their respective Regional Reliability councils. These guidelines, though currently voluntary, specify continual evaluation of the system's ability to deliver anticipated power demands even if one critical element of the system is out of service. The guidelines also outline the need for study of more severe scenarios such as having multiple facilities out of service at the same time. The guidelines specify that the system be designed and capable of operating within its rated capacities with one critical element out of service and that



the system can be controlled if multiple elements are out of service. The recently enacted federal energy bill directs FERC to ensure the establishment of mandatory reliability standards, which will presumably be based on the NERC model.

Adequacy to Serve Bulk, Wholesale Transfers

The growth of the competitive wholesale market for electricity has placed increasing demands on the transmission system which was built primarily to facilitate intrastate transfers from generation to distribution. Bulk wholesale power transfers require strong interconnections between adjacent transmission systems. Peabody Energy points out that power transfers from north of Kentucky to south of Kentucky, and vice versa, are limited by the lack of interconnection between Kentucky's regulated utilities and TVA. Administrative Case No. 387 found the same limitations to north-south flows, as have transmission planning studies conducted by MISO.

These limitations restrict the ability of Kentucky's utilities to export excess capacity and benefit from off-system sales. The congestion on the bulk transmission system, at times, limits the ability of Kentucky's regulated utilities to serve their customers from their lowest cost generation raising their generation costs.

Constructing facilities to improve these interconnections and relieve constraints would allow more economic wholesale transfers to occur and may make it more feasible for independent power producers to locate in Kentucky. There is much debate within RTOs and at FERC concerning how to determine the beneficiaries of such improvements and who should bear the cost of construction. Some of the additional transmission interconnections that have been discussed may not be necessary for Kentucky's regulated utilities to meet their obligations to reliably and economically serve their customers. While many of the transmission constraints impacting Kentucky are primarily the result of the wholesale electricity market, it is unclear the extent to which transmission upgrades would enable some Kentuckians to benefit from lower cost power or other Kentuckians to benefit from increased sales by their utility.

Vulnerability to Cascading Outages

The record of this case includes a January 24, 2005 report prepared for the Commission by Commonwealth Associates, Inc. (CAI) entitled *Assessment of Kentucky's Transmission System Vulnerability to Electrical Disturbance.* The study focused on the design of Kentucky's transmission system and assumed that the system is maintained adequately. The report discusses the results of an evaluation of how vulnerable the electric transmission system in and around Kentucky is to cascading outages similar to those experienced in the northeast and upper Midwest on August 14, 2003.

(On August 14, 2003, the Northeastern U.S. and portions of Ontario, Canada experienced power blackouts initiated by high voltage transmission line failure in northern Ohio. See *U.S. - Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004.)

CAI's central conclusion was that there were certain possible circumstances where the loss of multiple transmission facilities could result in widespread outages. CAI went on to say that,

[I]t may be that detailed review by the utilities or others will show that the possibility can be precluded. It would not be unusual to expect that detailed studies by the utilities that have more intimate knowledge of their systems, along with more detailed models, would result in the elimination of many, if not all, of the base case scenarios. Alternately if scenarios cannot be eliminated, then mitigation measures such as changes to system protection, system operating procedures, or new facilities would be investigated. If adopted, these changes might eliminate the reasonable possibility of widespread outages.

(Assessment of Kentucky's Transmission System Vulnerability to Electrical Disturbances. (January 24, 2005, at 3).)

Each jurisdictional high voltage transmission owner has certified to the Commission that it has addressed each of the scenarios identified as potential problems in the CAI study to minimize the risk of widespread outage from them. TVA is not jurisdictional to the Commission but its transmission planners do have the CAI results for consideration.

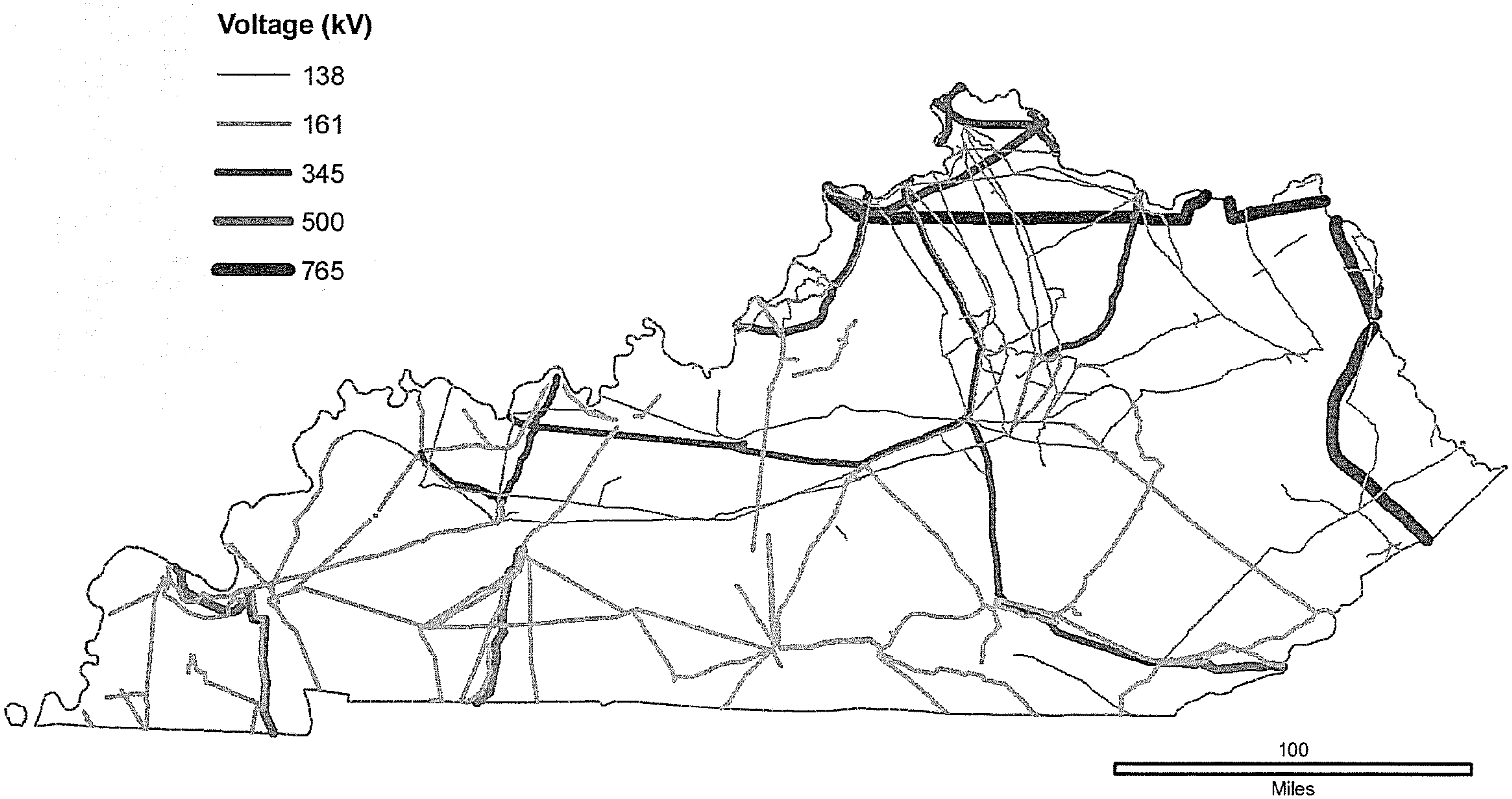
A map of Kentucky's high-voltage transmission system follows on the next page.

CAI also noted that since Kentucky has generating sources that meet or exceed the load within the state, it is reasonable to infer that Kentucky is less vulnerable to widespread outages than areas that must import power to meet load. CAI stated that the study "results imply that the grid is more than twice as vulnerable to widespread outages during a large transfer across Kentucky than it is under base or 'normal' conditions."

CAI concluded that the Kentucky transmission system was not designed to handle the level of interstate power transfers now being experienced which are in the magnitude of 6,000 MW.

Since Kentucky has generating sources that meet or exceed the load within the state, it is reasonable to infer that Kentucky is less vulnerable to widespread outages than areas that must import power to meet load.

Voltages of the Electric Transmission System



Maintenance and Vegetation Management

For the transmission system to provide reliable service, it must be maintained properly. Each of the jurisdictional transmission providers has a schedule for inspecting its transmission system, and each has a schedule for clearing vegetation within its transmission right-of-way (ROW). These schedules are as follow (Based on staff analysis of the responses to Staff's First Data Request, dated March 10, 2005, Item 32.):

Company	Aerial Inspection	Ground Inspection	Vegetation Control
Big Rivers	6 per year	5 year cycle	4 year cycle
East Kentucky Power	3 per year	4 year cycle	5 year cycle
Kentucky Power	2 per year	10 year cycle	Based on need
KU and LG&E	4 per year	10 year cycle	5 year cycle

The utilities use both herbicides and mechanical means to control vegetation growth within the ROW. The transmission ROW clearing and inspection costs for 2002 through 2004 are as follows (source as above):

Company	2002	2003	2004
Big Rivers	$ 511,300	$ 512,200	$ 507,400
East Kentucky Power	2,033,896	1,770,825	1,651,626
Kentucky Power	1,347,870	1,333,051	1,372,518
KU	2,891,521	3,340,527	2,453,400
LG&E	470,516	455,750	308,272

Big Rivers provided budget information. The information provided by the other utilities is actual cost.

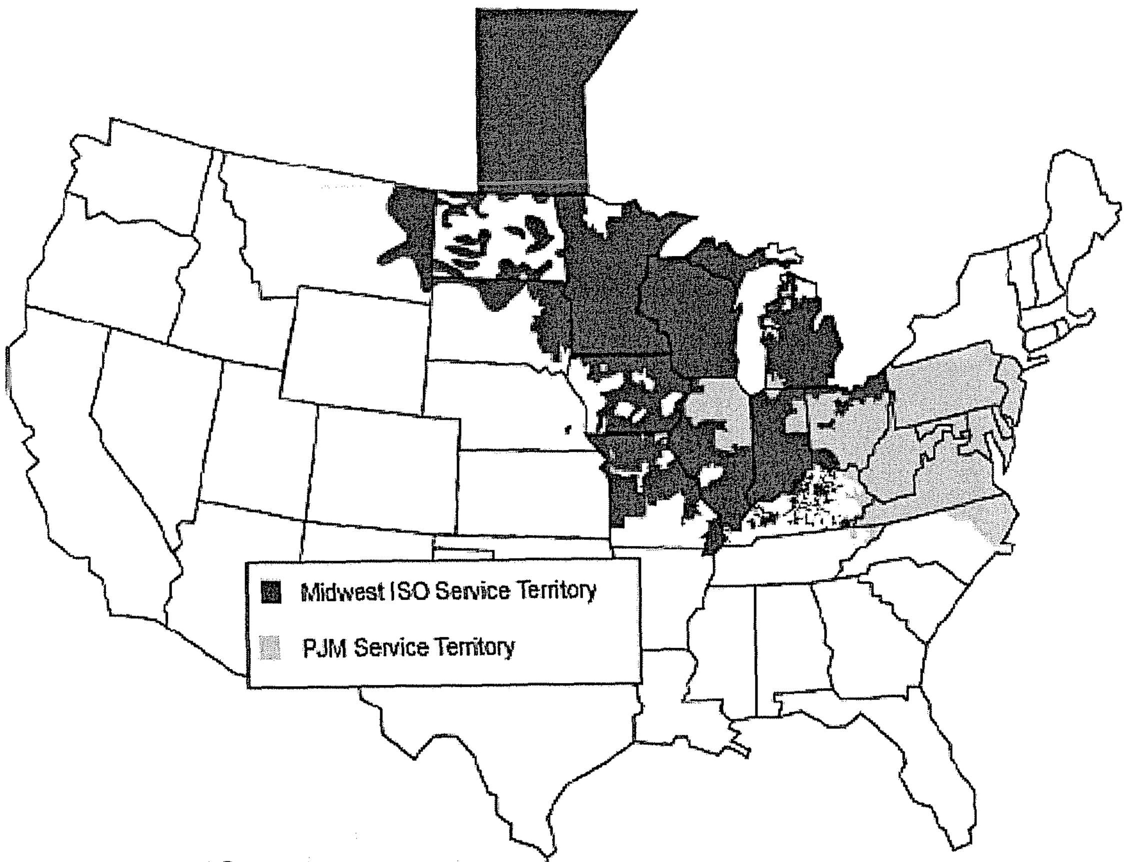
Regional Transmission Organizations

Four Kentucky electric utilities are currently members of RTOs. LG&E, KU and ULH&P (as an affiliate of Cinergy) are members of MISO, and Kentucky Power is a member of PJM. The continued membership of KU and LG&E in MISO is the subject of a case currently pending before the Commission. *(Case No. 2003-00266, Investigation Into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.)*

Big Rivers and East Kentucky Power are not members of an RTO but utilize TVA to coordinate their transmission systems, pursuant to NERC operating rules.

The MISO operated transmission system spans 15 states and 1.2 million square miles. MISO is required by its charter to assess infrastructure needs on a regional basis and, in order to ensure reliability of the regional system, may suggest state-based solutions or alternatives that may build upon initiatives being undertaken in other states within the Midwest.

Midwest ISO and PJM Interconnection Inc.
National Service Areas



SOURCE: MISO

In addition, MISO identifies transmission expansion that is critical to support the competitive supply of electric power across the system.

PJM serves as the FERC approved RTO in a 13 state region that includes parts of eastern Kentucky. One of the recent initiatives under exploration at PJM is "Project Mountaineer," an initiative to utilize a regional transmission planning process to explore ways to further develop an efficient transmission "super-highway" to bring low cost coal resources to market. At this point, it should not be considered a proposal for any specific transmission line but a commitment to utilize a Regional Transmission Expansion Planning process involving various states including Kentucky, the FERC, and the transmission owners.

This project seeks to explore new transmission opportunities to improve reliability and to enhance markets for low cost energy resources. PJM states that enhancing the transmission system in this manner will bolster economic development throughout Kentucky and in the other states, prompted by a resurgence in coal resource development and utilization. This key initiative must be diligently explored by Kentucky prior to any implementation. An issue to consider is whether the resulting economic benefits will outweigh the increased transmission costs and environmental concerns associated with providing power beyond what is required to serve Kentucky's native load customers.

<u>Siting of Transmission Lines</u>

The siting of facilities to be used for the transmission of electricity involves consideration of many issues, some of which are generally considered local in nature. These local issues include land-use management, visual impacts, and planning and zoning. KRS 100.324(1) exempts all service facilities to be located or relocated by a utility operating under the jurisdiction of this Commission or the FERC from local planning and zoning requirements. However, electric utilities are required by Kentucky statute to construct facilities to provide adequate and continuous service to the public within their territories.

Kentucky's jurisdictional utilities that operate under the jurisdiction of the Commission must obtain Commission approval before they construct any major transmission facilities. A 2004 amendment to KRS 278.020 gave the Commission authorization to regulate the construction of transmission lines that will operate at 138 kV or higher and that are longer than 5,280 feet. KRS 278.020 does not directly address siting issues for transmission facilities but addresses the need of the proposed facility.

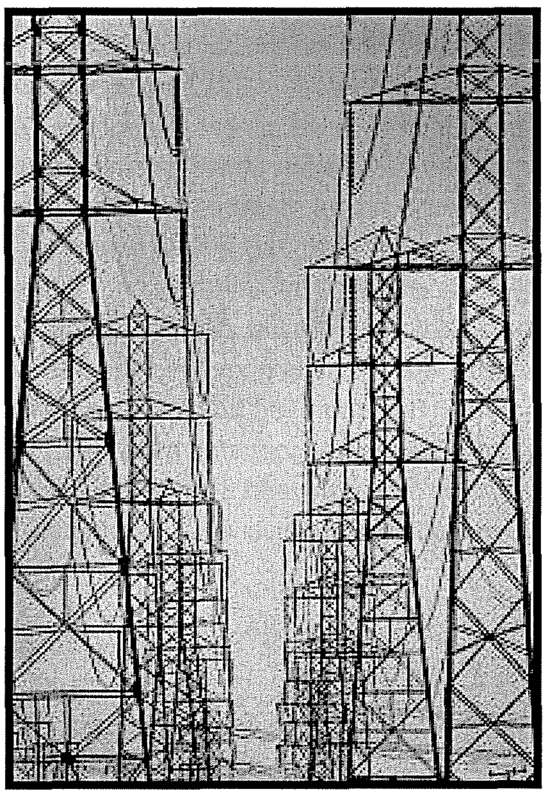
Non-jurisdictional entities that propose to build a transmission line that will operate at 69 kV or higher must first receive a certificate from the Siting Board. The requirements of KRS 278.714 do not address the need for the facility but do address siting issues such as the impact on Kentucky's scenic assets. New and developing technologies such as utilization of lightweight, non-metallic conductors and current limiting reactors can increase the capacity of existing transmission lines thus delaying or eliminating the need for new routes. Kentucky's electric utilities should be encouraged to investigate new and developing technologies that can increase the capacity of existing transmission facilities.

The Comprehensive Energy Bill signed into law by President Bush on August 8, 2005 contains provisions regarding the siting of the nation's bulk transmission grid. The provision may impact Kentucky's ability to regulate the siting of transmission lines within our borders.

The bill includes provisions to require the DOE to study and designate "national interest electric transmission corridors." Within one year from the date of enactment of the Bill and each three years thereafter, DOE, in conjunction with affected states, will designate these corridors based upon transmission capacity constraints or congestion that adversely affects consumers. There are many factors taken into consideration when making this designation, but in part, DOE may consider (1) whether economic vitality or development in a corridor or in end markets served by the corridor are constrained due to the lack of adequate or reasonably priced electricity; and (2) whether the designation would be in the interest of national energy policy. This designation as a "national interest electric transmission corridor" is important because once these corridors are selected, FERC has authority to site transmission facilities within these corridors if states cannot or will not site the facilities within one year.

Kentucky's situation between northern and southern load centers, coupled with the aforementioned constraints on north-south power transfers within Kentucky, present the possibility that one or more "national interest electric transmission corridors" through Kentucky will be identified. That designation will give FERC siting jurisdiction if Kentucky fails to certificate, within 1 year, a request for transmission expansion in the identified corridors for facilities within that corridor. It is not yet determined who will pay for these transmission facilities to be constructed, although it is safe to assume that such information would be included in any request for such a transmission certificate.

The Commission agrees with recommendation number 43 of the Energy Policy Task Force's *Comprehensive Energy Strategy*. Kentucky should ensure its "place at the table" with the federal energy regulatory agencies to protect the interests of the Commonwealth, particularly with regard to any designation of national interest transmission corridors and development of regional electricity markets.



Resource Adequacy-Distribution

Electric distribution utilities are companies that provide electric service to end-use residential, commercial and industrial customers. Distribution facilities include power lines, facilities operating at voltages of less than 69 kV, and service line drops to customer meters. A a map showing the distribution utilities in Kentucky and their territories follows on the next page.

There are three types of electric companies providing distribution service in Kentucky: rural electric distribution cooperatives, municipal utilities and investor-owned utilities. The majority of the 24 distribution cooperatives are jurisdictional, 3 of which purchase their power from Big Rivers and 16 of which purchase their power from East Kentucky Power, and are commonly described as generation and transmission cooperatives. Currently, there are five non-jurisdictional distribution cooperatives operating in Kentucky that purchase their power from TVA. The 30 municipal utilities that provide distribution service in Kentucky are not regulated by the Commission.

New Technology

While none of the electric utilities identified any pure research projects in which they were involved regarding distribution reliability, efficiency, or safety improvement, they indicated that they are actively evaluating and implementing new technology and other means to improve the efficiency and reliability of their distribution systems. The Commission believes that such activity is important and should be continued. We encourage the electric utilities to review and analyze the research of new technologies, products and programs proposed in the new federal energy bill and currently performed by The Edison Electric Institute, the Electric Power Research Institute and other electric industry organization that performs such research. Where practical, the Commission encourages the electric utilities to share such information with their peers.

Distribution System Reliability

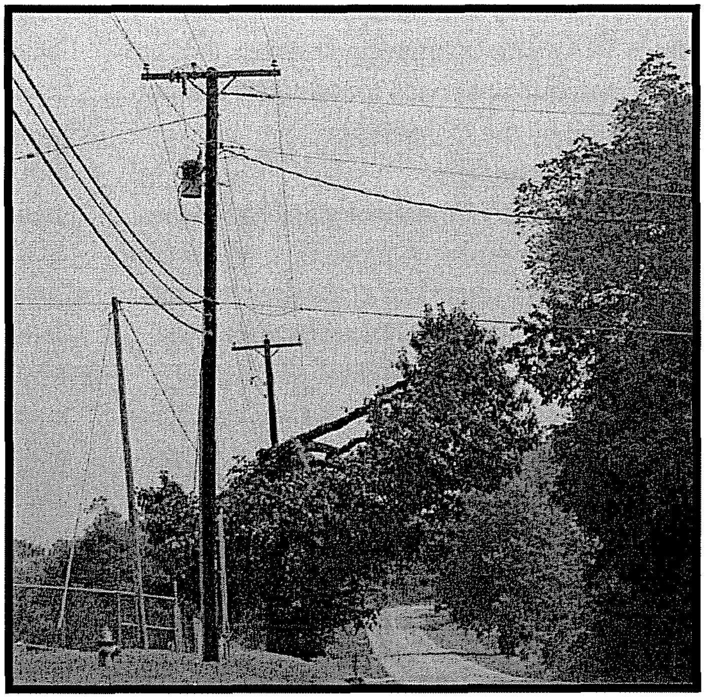
The Commission believes that electric distribution utilities should be encouraged to explore proven state of the art technology to implement cost-effective electric service reliability improvements. While the electric utilities responded that they had implemented reliability improvement programs, there were significant differences in the degree of sophistication of the programs. The Commission believes that it is important for each electric distribution utility to have formal programs to improve and maintain acceptable reliability levels. Such programs should include: (1) load forecasts; (2) formal system reviews; (3) targeted objectives; and (4) appropriate procedures to guide field personnel. In terms of the targeted objectives, the use of the SAIDI, System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) indices, as well as other indices that may be appropriate, should be used to determine system-wide and localized feeder benchmarks against which performance can be measured each year. This, along with other information, could assist the electric utilities in identifying the distribution feeders with the poorest reliability and planning appropriate corrective action.

The establishment of a single state-wide reliability standard for use by all electric utilities in Kentucky may be impractical, given the diverse geographic characteristics and population density of the State. However, the Commission believes that it is important that each utility utilize standard criteria in the calculation of its own internal indices to enable some form of comparison among the utilities. This could include establishing standard criteria for excluding major events, the units of time to be used, and the detail to which system reliability will be measured. This could also assist utilities in establishing consistent benchmarks to measure annual or periodic performance. The electric utilities could use this information to objectively evaluate the effectiveness of their reliability improvement programs and provide greater consistency when reporting the results of their reliability improvement programs to the Commission or other regulatory bodies.

Right-Of-Way Maintenance and Vegetation Management

An effective ROW or vegetation management program, cutting trees or branches which may come into contact with distribution lines, can help reduce outages during storms or severe weather. We are also aware that for all the benefits ROW clearing can provide, property owners, for aesthetic reasons, are sometimes hesitant to allow the utilities to trim or cut their trees.

There is no current regulation in Kentucky which specifies the frequency or width of ROW clearance for distribution lines. When asked at the technical conference about the need to establish such a standard, all the jurisdictional electric utilities stated that it would be appropriate for the Commission to address this issue with each individual utility in the context of a rate case, but that standard clearance parameters should not be established. The Commission recognizes the difficulties electric utilities can encounter with property owners regarding ROW clearing. Furthermore, we are concerned that the reluctance of some property owners to allow proper trimming of their trees negatively impacts the reliability of entire distribution systems. Perhaps through the establishment of a distribution ROW clearance requirement, the electric utilities' ability to keep branches away from their lines and improve the reliability of the electric service would be enhanced. Therefore, the Commission believes that further consideration should be given to the establishment of some practical distribution vegetation management clearing parameters for Kentucky's jurisdictional electric distribution utilities.



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Energy Efficiency, Demand-Side Management and Conservation

In 1994, the General Assembly enacted legislation that was codified as KRS 278.285, which allows jurisdictional utilities to submit DSM plans and request recovery of DSM costs outside a general rate case through a DSM surcharge. Since that time, formal DSM plans and cost-recovery mechanisms (more commonly known as DSM surcharges) have been approved by the Commission for Kentucky Power, KU, LG&E, and ULH&P. While not submitting formal plans, both Big Rivers and East Kentucky Power, in conjunction with their member cooperatives, have developed and offered DSM programs to the retail customers of the member systems.

Although the jurisdictional utilities have a number of DSM programs in place, because of relatively low electric rates, many programs that have been cost-effective in other regions have not been shown to be cost-effective in Kentucky. However, as the incremental cost of new generation continues to increase, as fuel costs increase and as new environmental requirements increase the cost of all generation, the Commission believes that utilities will need to give greater consideration to energy efficiency measures, DSM programs, and conservation programs as tools for addressing a larger portion of their customers' demand.

As the costs of fuels for generation increases, and the costs of burning and disposing of those fuels increases as well, the relative costs of efficiency measures, conservation and DSM programs are expected to become more competitive with the costs of generation. This will result in greater investment by the electric utilities in efficiency, conservation and DSM measures.

Many aspects of the expanded role of DSM and energy efficiency measures recommended by the Kentucky Resources Council (KRC), Energy Systems Group, LLC (ESG) and other parties are beyond the scope of utility operations as well as the jurisdiction of the Commission. However, they are consistent with many of the recommendations contained in the *Comprehensive Energy Strategy* developed by the Commonwealth Energy Policy Task Force.

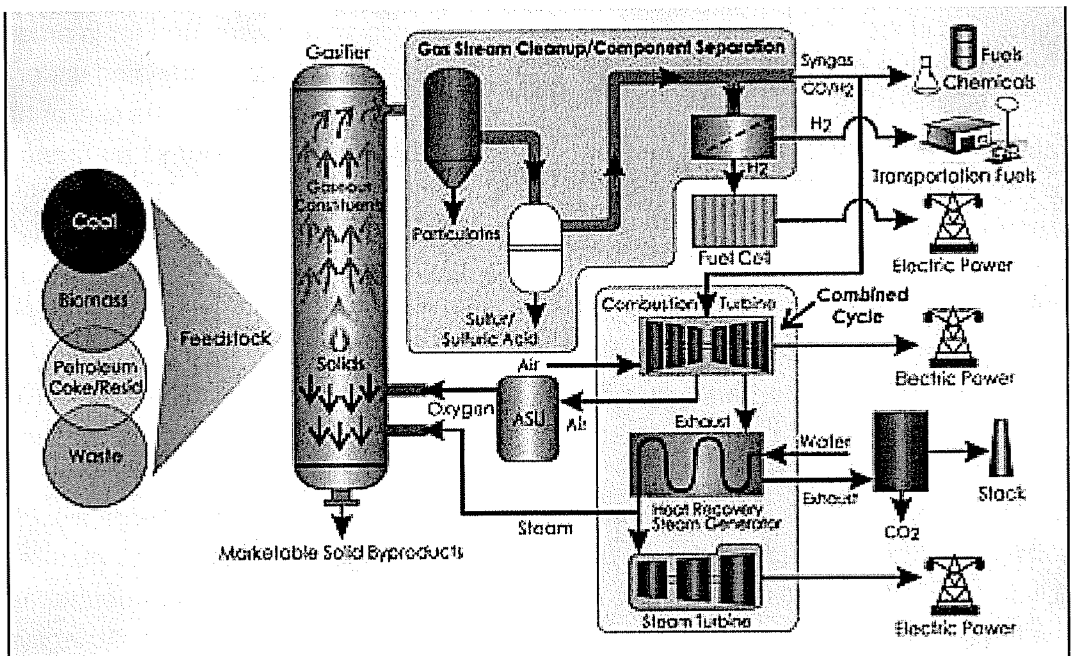
Promoting energy efficient practices, examining building codes, and increasing public awareness and education on energy efficiency issues are efforts that the Commission believes should be pursued by Kentucky's public policy makers. As we also note in discussing environmental compliance issues, greater use of energy efficient products and enhanced efforts to implement practical DSM and conservation measures can have a positive impact on the environment and should be considered in the development of Kentucky's future energy policy.

Efforts to implement practical DSM and conservation measures can have a positive impact on the environment.

Renewables and Alternative Technologies

As Kentucky's generating fleet ages and needs to be replaced, and as environmental requirements become more restrictive, the use of renewables and alternative generation technology becomes more important and cost-effective. Many jurisdictional and several non-jurisdictional electric utilities currently offer their customers the option of purchasing "Green Power," which is derived from renewable sources. However, due to the higher cost to generate power from most renewable resources, "Green Power" is sold at a premium price. In addition, most of the jurisdictional generating utilities indicated that they or their affiliates are investigating the use of renewables and alternative generation technology. These include biomass, hydro, solar, wind as well as IGCC and other clean coal technology. Also, all jurisdictional electric utilities have filed net-metering tariffs pursuant to KRS 278.466, which was enacted to promote the use of small scale renewables by residential and commercial customers.

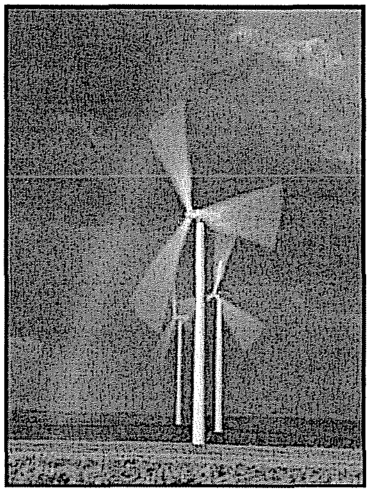
Recommendation 18 of he Governor's *Comprehensive Energy Strategy* calls for the design and implementation of policies to promote, rather than mandate, the use of renewable energy resources as part of Kentucky's energy portfolio. The Commission, therefore, believes that it is important to encourage utilities and other interested parties to work to expand the use of renewables. Kentucky's energy policy should consider the value of renewables and provide appropriate financial



Integrated Gasification Combined Cycle (IGCC)

incentives to those investing in generation using renewables so that such generation becomes economically viable for use by Kentucky's utilities. Such incentives could include grants, low interest loans, and tax credits.

Some participants urged that the full cost of environmental impacts and other externalities be included in the price of coal-fired electricity to reduce the cost differential between coal-fired generation and renewables or other alternative technologies. However, the Commission does not believe such a step is necessary or appropriate at this time.



As we state in the Externalities and Environmental Compliance sections of this report, the identification and quantification of the related costs is impractical. In addition, the inclusion of externalities in the price of electricity implies that those that consume electricity are solely responsible for the existence of the externalities. Such implication may be inaccurate and thus result in an inappropriate transfer of costs.

Other states have assured rate recovery or granted higher returns on investments in renewable generation. These actions would raise the cost of electricity to Kentucky's consumers and are less preferable than other identified incentives at this time.

In addition to incentives for investment, it is also important that Kentucky's energy policy include an effort to educate the public regarding the benefits of renewables.

Other than renewables, IGCC technology was the predominant clean coal technology discussed in this proceeding. Like renewables, this technology is also currently more expensive than conventional fossil fuel generation. In addition, there are still concerns regarding the operating reliability of this developing technology, although the predominant manufacturer, GE, is taking steps to mitigate this risk. Some now argue that IGCC units may be the generation choice of the future because of the ability to sequester carbon dioxide (CO_2).

As with renewables, the *Comprehensive Energy Strategy* included a recommendation to promote investment in clean-coal technology. With regard to more expensive IGCC technology, it is unclear whether it would be eligible for a CPCN under KRS 278.020 or how its environmental benefits could be accounted for in an environmental surcharge proceeding under KRS 278.183. Financial incentives similar to those that may be developed for renewables should be available for IGCC or closely related technology. One additional financial incentive discussed for IGCC investment that should be considered is that of securitization.

(As described by KIUC, securitization is a financing option that allows a utility to finance assets with 100 percent debt at the most attractive investment grade rates. A rate mechanism such as a surcharge would charge all customers benefiting from the financing until all bonds have been repaid. Securitization would require specific legislation.)

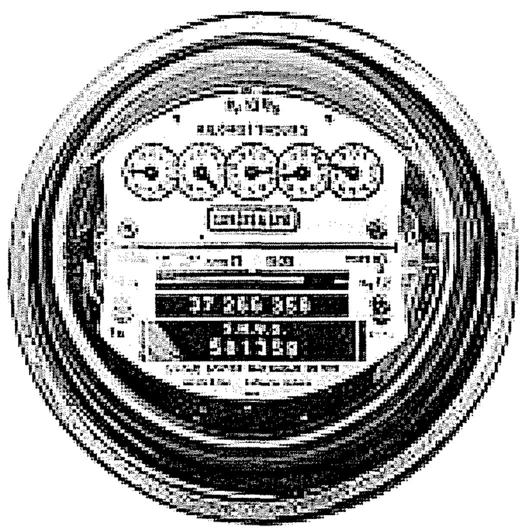
Externalities

The comments of the non-utility panel participants and members of the public participating at the technical conference heavily referenced externalities, which generally refer to external costs imposed without being accounted for in the cost of a product. The most significant of the externalities identified were emissions from coal-fired generating units. These are addressed in a separate Environmental Compliance section because environmental compliance is an issue that has an overriding impact on every resource acquisition decision of the electric utilities.

In this proceeding, the Commission heard from those who advocate including the full cost of externalities in the price of electricity. Neither the electric utilities nor other parties who might disagree have had the opportunity to comment or rebut the comments of those who advocate the inclusion of externalities in the price of electricity. The pros and cons should be considered and evaluated before any determination is made regarding externalities in relation to Kentucky's energy policy.

The costs of some externalities are already included in the price of electricity. The costs to comply with environmental emissions requirements are included in the utilities' generation resource acquisition decisions as well as in the evaluation made with regard to retrofitting existing generating units. In addition, most of the jurisdictional generators have implemented environmental compliance plans and environmental surcharges. The costs of land reclamation, compliance with regulations and other costs relating to coal production are included in the cost of coal. However, the potential exists that all related externalities are not fully included in the cost of coal since coal is a commodity and subject to competitive market pressures. To address the ideal proposed by some participants in this proceeding and include the full cost of externalities in the price of electricity would certainly increase the price of electricity or reduce utility revenues. There may be undesired or unintended consequences as a result.

The Commission believes that cautious consideration must be given to the inclusion of any externality in the price of electricity. The inclusion of externalities in the price of electricity implies that those that consume electricity are solely responsible for the existence of the externalities. Such implication may be inaccurate and thus result in an inappropriate transfer of costs. The Commission does not have jurisdiction under KRS Chapter 278 to explicitly allow for consideration of such externalities.



Environmental Compliance

As noted above, the jurisdictional utilities are required to comply with numerous environmental requirements as part of doing business. Although state and federal agencies other than the Commission are responsible for enforcing environmental compliance, the Commission deals with utilities on environmental issues in a number of ways. These include: (1) integrated resource planning; (2) filings made pursuant to KRS 278.183, the environmental surcharge statute; and (3) CPCN proceedings for approval to construct environmental facilities.

As part of their IRP, the utilities are required to forecast their demand and energy sales for a 15-year planning horizon and demonstrate how they plan their resources to meet those forecasts. They must include environmental impacts in the criteria used to screen potential resource options, identify the actions to be taken during the planning horizon to comply with the Clean Air Act Amendments of 1990, and describe how those actions will affect their resource plan. The environmental compliance measures identified within the IRP proceeding often come before the Commission at a later date as part of a utility's application for an environmental surcharge under KRS 278.183 or for a CPCN under KRS 278.020(1).

In an environmental surcharge proceeding, a utility may seek to recover environmental compliance costs through an environmental surcharge. To do so, it must file a plan that addresses compliance with applicable federal, state, or local requirements, and it must relate only to generating electricity through coal combustion. The plan must address a reasonable return on related capital expenditures and include a tariff that establishes the terms and conditions of the surcharge. The Commission must determine whether the plan and surcharge are a reasonable and cost-effective means of (1) complying with the applicable environmental requirements and (2) recovering the related costs.

Depending on specific components of a utility's environmental compliance plan, a CPCN application may be submitted for Commission approval to install specific environmental comliance facilities at the utility's generating units. Such CPCN proceedings, which are covered by the provisions of KRS 278.020(1), have typically involved flue gas desulphurization systems, commonly known as "scrubbers," and selective catalytic reduction facilities (SCRs). These facilities, that cost millions of dollars, are necessary to comply with environmental emissions standards for fine particulates and chemicals such as sulfur dioxide and nitrogen oxide that are released during generation.

It is through these various regulatory proceedings that the Commission and Commission Staff monitor and review the manner in which utilities pursue compliance with environmental standards, implement their compliance plans, and seek to recover the related costs.

Currently, four utilities, East Kentucky Power, Kentucky Power, KU and LG&E, are operating under Commission approved environmental surcharges. Big Rivers had an environmental surcharge for approximately three years but terminated it prior to its bankruptcy filing. ULH&P, which currently purchases its power from its parent company, has not requested an environmental surcharge.

The compliance related capital investments included in all of the environmental compliance plans approved for the jurisdictional utilities total $2.068 billion. The following is a breakdown of investments by utility:

Company	Investment Pursuant to an Approved Environmental Compliance Plan
Big Rivers	$208.4 million
East Kentucky Power	$198.7 million
Kentucky Power	$172.6 million
Kentucky Utilities	$1,163.4 million
Louisville Gas & Electric	$324.9 million

Clearly, the cost of environmental compliance has had a significant impact on the cost of generating electricity. In fact, no other cost has had the impact of environmental compliance in recent years. Accordingly, each jurisdictional electric generating utility stated, in some fashion, its concern with the likelihood of more restrictive environmental requirements and increased costs to comply.

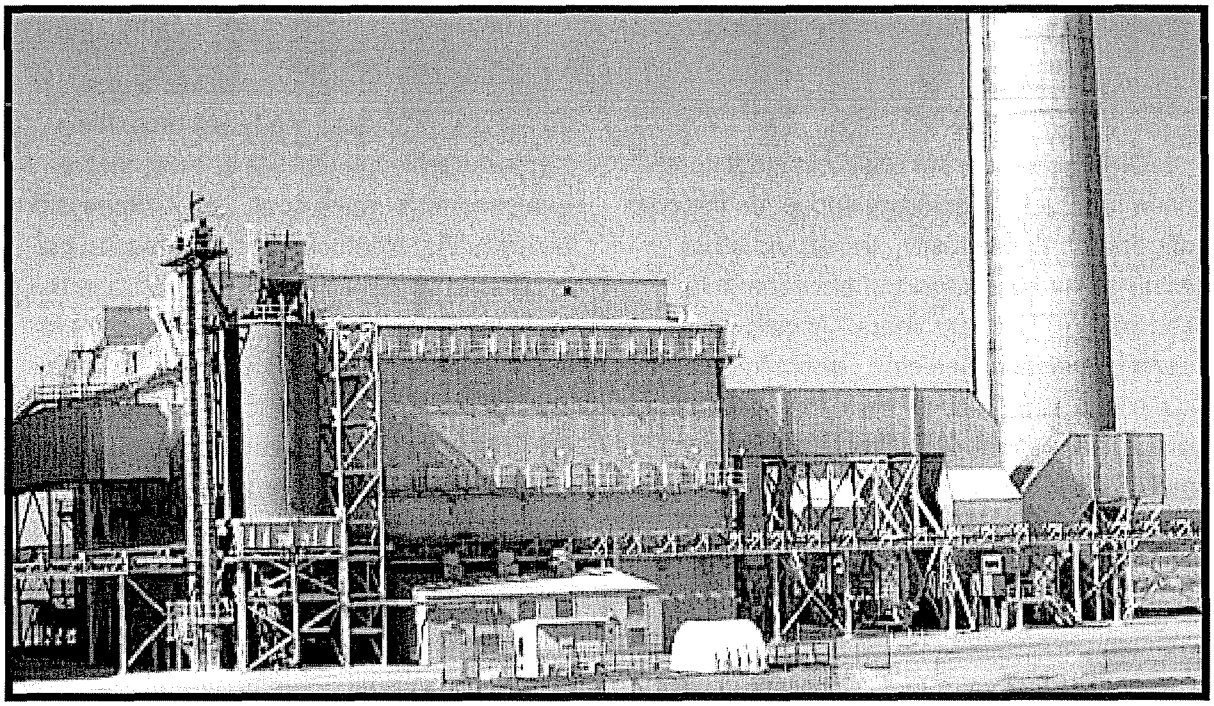
The Commission shares this concern. However, as previously noted, the Commission lacks jurisdiction relating to environmental requirements which are, for the most part, federally mandated. The Kentucky Environmental and Public Protection Cabinet (EPPC) has some limited authority; however, the majority of its efforts are to implement and enforce the federal requirements which, as it notes, are expected to become more restrictive.

As EPPC notes, even though the use of coal for electricity generation has increased by 75 percent since 1970, total power plant emissions have declined by 40 percent. While we share the concerns noted by KRC and other participants regarding environmental related externalities (other than environmental compliance related), we do not believe it is appropriate to place an additional cost burden on electric customers as some suggest. In this proceeding, the utilities have indicated their willingness to implement sound and reasonable environmental policy. In their resource plans, the utilities have considered and evaluated the latest technology. Kentucky's electric utilities should not be punished for burning coal. The Commission believes that Kentucky's environmental policy should be balanced. We encourage the electric utilities, the EPPC and other appropriate agencies and organizations to participate at the federal level to ensure that sound environmental policy is developed.

The Governor's Energy Policy Task Force also indicated its concern with environmental issues. The *Comprehensive Energy Strategy* contains no fewer than 20 recommendations relating to environmental issues, including: (1) promoting the use of energy efficient products and educating the public regarding their benefits; (2) promoting the use of renewables and alternative generation technologies including clean coal technology; (3) continuing aggressive policies regarding mine-site reclamation and the recovery of abandoned coal refuse; and (4) addressing the general concern of environmental quality. The Commission agrees with these recommendations and believes that these efforts should be part of Kentucky's future energy policy.

Kentucky's electric utilities have already taken some of the steps included in those recommendations. All the electric utilities offer DSM programs and provide incentives for the purchase and installation of energy efficient products. Pursuant to KRS 278.466, all have tariffs to allow net-metering. Most are evaluating or participating in the evaluation of renewables and alternative technology while some are already generating power from alternative technology.

As noted in the Energy Efficiency, Demand-Side Management and Conservation section of this report, the greater use of energy efficient products and DSM will result in a lower demand for electric energy. We believe that research on and development of energy efficient products and the use of renewables and alternative technology for electricity generation should be encouraged in developing Kentucky's future energy policy, and that incentives such as tax credits, grants and low interest loans should be considered to foster such activities.



Barriers to Infrastructure Investment

The focus of the pre-filed and oral comments regarding barriers to investment varied among the groups represented at the technical conference. The jurisdictional utilities and MEPAK cited barriers to their investment in facilities to serve their customer base. The comments of other participants were as diverse as the groups they represented, and, with the exception of Kentucky Pioneer and Peabody Energy, generally addressed barriers to investment in alternatives to coal-fired generation.

At the technical conference each jurisdictional utility representative adopted and seconded the comments made by their peers. For jurisdictional utilities, barriers included: merchant plants, change in tax policy, environmental compliance, federal versus state authority, deregulation, and rate uncertainty.

Merchant plants were noted as barriers because some believe they would reduce the available emissions capacity and negatively impact the environmental compliance options available to regulated utilities. This issue is addressed in the Merchant Plant section of this report.

The tax policy change refers to the Kentucky Revenue Department's decision that distribution and substation transformers are subject to sales tax based on its re-interpretation of a Revenue Department Circular. East Kentucky Power, itself, has been assessed almost $2 million for the period from February 1, 2001 through November 30, 2004. This policy change will impact all jurisdictional electric utilities and, given the estimate of East Kentucky Power, the impact could be significant.

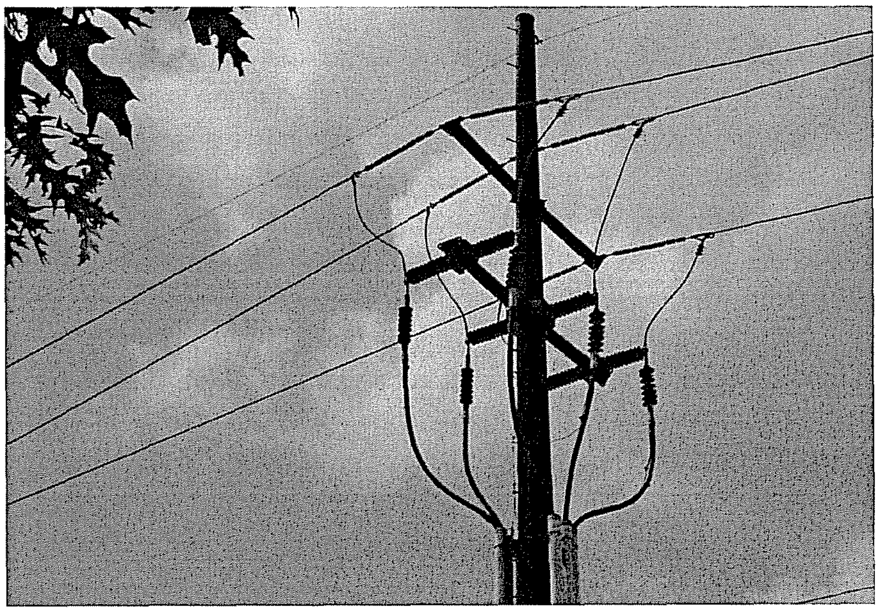
The Commission was unaware of this tax policy change until it was identified in this proceeding. We are not familiar with the legal basis or other reasons for this change in tax policy, nor would we normally have reason to be. However, within the context of the Governor's directive, we note that under traditional rate-making principles an increase in taxes assessed to a regulated electric utility will increase its cost to serve customers and will eventually result in a rate increase, all other factors being equal. The Commission recognizes the responsibility of all citizens and companies to bear their fair share of Kentucky's tax burden. Therefore, the Commission recommends that this issue be considered in Kentucky's energy policy in the context of its overall impact on both electricity rates and taxes.

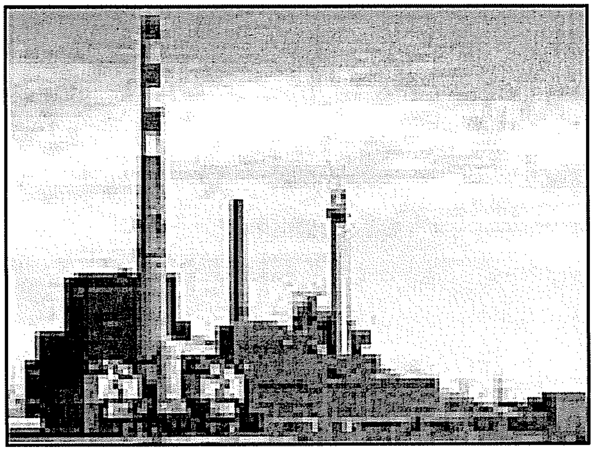
The jurisdictional electric utilities identified the issues of environmental compliance and federal versus state regulation as top issues facing Kentucky's electric power industry in the future and as the two most significant barriers. The issue of environmental compliance is addressed in an earlier section of this report.

The need to define the regulatory roles of the federal and state governments was specifically set forth by Kentucky Power in its comments but seconded by the other jurisdictional utility panelists at the technical conference. The issue of jurisdictional certainty encompasses a number of sub-issues relating to wholesale energy markets, transmission tariffs, the transmission grid itself, RTOs, siting of new facilities (particularly transmission) and generation needs. Each jurisdictional electric utility agreed that the federal government, through the FERC, has regulatory authority over wholesale energy markets, transmission tariffs, and generally the transmission grid. This Commission has authority over the provision of retail electric service including the rates for wholesale transmission when provided as part of a bundled retail sale. However, the distinction between the two has become somewhat ambiguous and continues to be so, particularly with regard to the emergence of RTOs.

Each jurisdictional electric utility addressed this ambiguity from the perspective of the issues important to them. Big Rivers discussed RTO membership and the absence of benefits of joining an RTO, arguing that Kentucky should reject RTO membership unless increased reliability, lower costs, or other benefits to offset the costs of membership can be demonstrated. East Kentucky Power also addressed the issue of RTOs, noting that while there may be operational advantages there are cost disadvantages. East Kentucky Power recommended that Kentucky prevent its utilities from joining RTOs unless membership is shown to be economically prudent. To support its position, East Kentucky Power discussed the negative impact of accommodating Transmission Loading Relief orders (TLRs) and its perception that there is a lack of coordination between MISO and other regions.

Kentucky Power briefly discussed transmission siting authority as an issue of concern, stating that FERC should have siting authority and the power of eminent domain relative to the transmission grid. In comments at the technical conference, Kentucky Power qualified its prior position by stating that it intended for such federal power to be used when states were barriers to transmission investment and that transmission siting was working in Kentucky. Kentucky Power cited a 90-mile transmission line an affiliate is constructing in Virginia and West Virginia that required 15 years to receive approval even though it was needed for reliability. Kentucky Power also stated that Kentucky needs to retain authority over generation and transmission. Finally, Kentucky Power recommended that Kentucky look into the "whole picture of RTOs" and capacity markets because of the economic consequences.





KU and LG&E also expressed concerns relating to RTOs. They cited decisions relating to generation dispatch and DSM, noting that state authority over these areas is being impacted by RTOs and wholesale energy markets. As members of an RTO, KU and LG&E indicate that they are now subject to a form of federal regulation focused primarily on regional issues rather than Kentucky issues and that this regulation hinders the Commission's ability to regulate solely in the best interests of Kentucky.

(The membership of KU and LG&E in MISO is currently under review by the Commission in Case No. 2003-00266, Investigation Into the Membership of Louisville Gas and Electric Company and Kentucky Utilities in the Midwest Independent Transmission System Operator, Inc. Subsequent to the establishment of that case, KU and LG&E gave notice to MISO of their intention to withdraw their membership.)

ULH&P, which is in the process of acquiring several generating units from its parent, recommended that the Commission work with the National Association of Regulatory Utility Commissioners (NARUC) and FERC to define the boundaries of jurisdiction relating to resource adequacy issues, more specifically those involving transfers of generating units between utility affiliates. ULH&P also discussed issues relating to RTOs. It indicated its concern with generation and transmission siting, which formerly involved only the utility.

Now siting is regional in focus and may be multi-regional because of ULH&P's membership in MISO and Kentucky Power's membership in PJM. ULH&P is also concerned with its ability to recover transmission related costs and recommended that the Commission approve trackers to recover such costs.

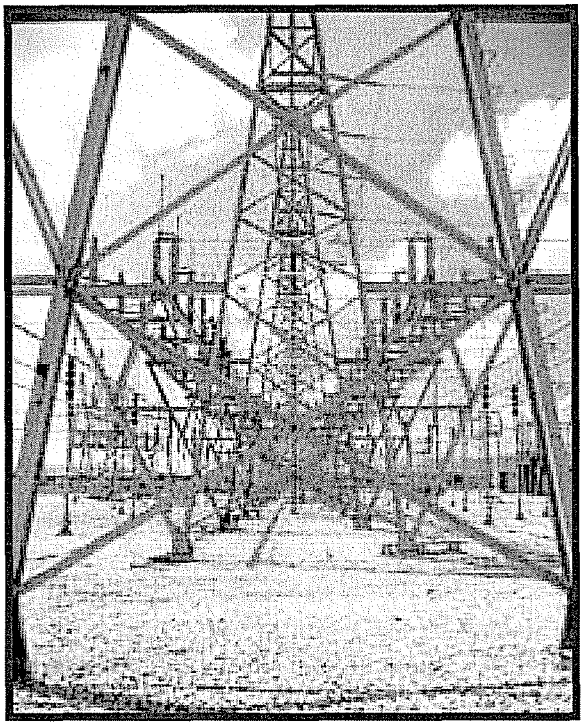
MEPAK also cited the issue of RTOs in its comments. MEPAK stated that its members rely on the transmission systems of others and noted the need for reasonable transmission costs, and it stated its concern that RTOs are costly with few benefits.

The Commission shares the concerns of the jurisdictional electric utilities regarding the issue of federal versus state jurisdiction. In the past, the Commission has intervened in cases before FERC to preserve its jurisdiction or to assert its rights. For example, in FERC Docket No. ER03-262-009, the Commission supported its authority to approve or deny Kentucky Power's application to join PJM, aggressively opposing FERC efforts to preempt the Commonwealth's jurisdiction. The list of issues spawned by the creation of RTOs is growing and the Commission is seemingly faced with ever decreasing authority as FERC addresses new issues regarding RTOs and transmission. Recognizing that RTOs are predominantly federally driven, we are unsure as to how Kentucky's energy policy can incorporate plans to address this issue.

Legislation has been passed in recent sessions of Kentucky's General Assembly to expand Kentucky's and the Commission's jurisdiction. Examples of such legislation include: (1) the 2002 enactment of statutes, KRS 278.700-278.716, creating the Siting Board, authorizing that Board to approve or disapprove the siting of non-regulated generation and transmission plants; (2) the 2003 enactment of KRS 278.216 extending many of those Siting Board requirements to Commission cases in which regulated utilities seek certificates for most generating plants; and (3) the 2004 amendment of KRS 278.020 giving the Commission jurisdiction to approve or disapprove major regulated transmission projects.

However, such actions cannot preserve the Commission's limited authority. Recommendation 43 of the *Comprehensive Energy Strategy* calls for Kentucky to engage federal regulatory and energy agencies to ensure Kentucky has "a place at the table" in the discussion of energy issues, and Recommendation 44 calls for Kentucky to investigate the impact of global and national policies on our energy future. The Commission fully supports these recommendations and will make its staff available to assist the Executive Branch, Kentucky's Legislative Branch and our federal legislators in this endeavor. In addition, we recommend that Kentucky's future energy policy include sufficient flexibility so that the Commonwealth may react to federal action quickly and efficiently.

ULH&P, whose parent, CG&E, operates in a restructured environment in Ohio, identified deregulation as a concern. ULH&P cited the California energy crisis, the bankruptcies of Enron and Mirant, and the fact that retail



competition could result in higher rates for Kentucky customers as reasons to be cautious regarding deregulation. ULH&P urged the Legislature and Commission to continue a "wait and see" approach.

Pursuant to House Joint Resolution 95, passed in the 1998 legislative session, the Commission Staff, during 1999 and 2000, participated with staff of the Legislative Research Commission (LRC) and an independent consultant to review the issue of electric restructuring in Kentucky. The findings, which were presented to the Special Task Force on Electric Restructuring (Special Task Force) generally found that there were few positive benefits to Kentucky and that there was no compelling reason for Kentucky to restructure.

(The Special Task Force was established by Joint Resolution 95 during the 1998 legislative session of the General Assembly. The Special Task Force consisted of 20 members

from both the executive and legislative branches and was charged with assessing the impact of allowing electric retail competition in Kentucky.)

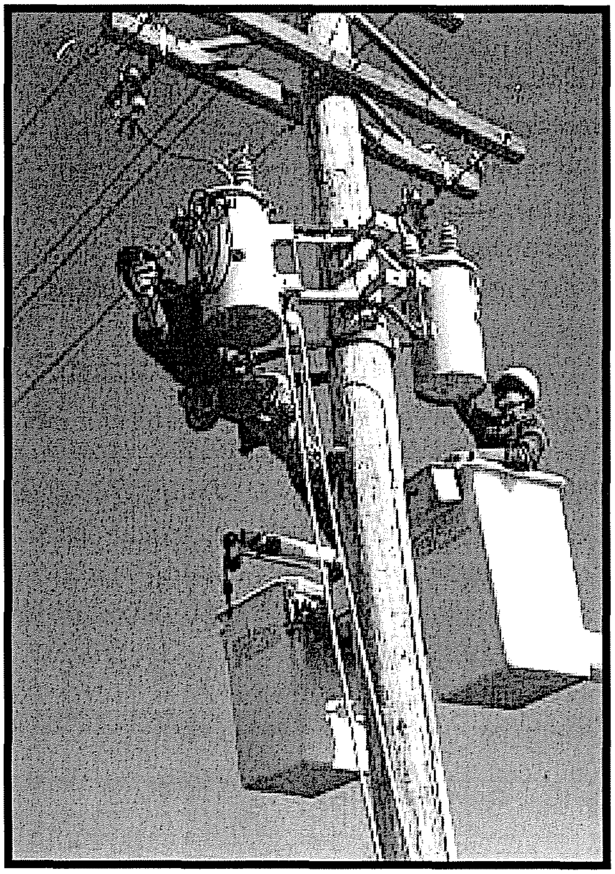
As a result, the Special Task Force recommended that the 2000 General Assembly take no action to restructure Kentucky's electric industry. Since that time, several factors, not the least of which are the California energy crisis and Enron's bankruptcy, have caused states that were restructuring to reassess and reconsider their efforts. The Commission believes, as the report to the Special Task Force suggests, that in the future Kentucky may be forced to move toward restructuring as a result of federal legislation and FERC actions.

Changes are already taking place as the result of open access transmission and the establishment of RTOs and competitive energy markets run by RTOs. The Commission still believes that Kentucky should continue its "wait and see" approach. We agree with the recommendation that Kentucky must have a place at the table in these discussions and work to maintain our status as a low cost energy state.

The barriers and other issues identified by other participants reflect concerns specific to the interests that they represent. Many of these, such as requiring increased investment in DSM programs and more energy efficient products, as well as the barriers to investment in merchant plants, renewables and alternative technologies, are addressed in other sections of this report; however, some are addressed here.

MEPAK discussed the lack of joint action authority as a significant barrier to investment. This is an issue important only to the municipal systems. In summary, joint action authority would enable the municipal systems to combine load and bonding capacity to enable them to acquire high grade financing at a lower cost than is currently available.

The issue of joint action authority is beyond the Commission's authority. The Commission has no jurisdiction over the municipal electric utilities and no authority regarding possible joint action legislation. We would, however, be concerned about such legislation to the extent that it could impact the jurisdictional utilities.



Regulatory Certainty

The Commission recognizes that changes within the electric industry in recent years have created greater uncertainty than previously existed. However, we believe that the regulatory scheme in Kentucky has been successful, as many parties stated, due in part to the measured and deliberate approach that has been taken to address various issues.

To the extent that cost recovery and regulatory certainty are concerns, it is worth noting that when new rates are filed, the five- and six-month suspension periods established in KRS 278.190 are among the shortest in the nation. Furthermore, the utilities have been assured of timely recovery of increases in fuel costs through the use of a fuel adjustment clause under the provisions of 807 KAR 5:056, which was established in 1978.

In addition, utilities have the ability to recover the costs of environmental compliance on a nearly real time basis via an environmental surcharge, pursuant to KRS 278.183, which was established in 1992. Finally, DSM costs, including lost revenues and financial incentives, have been recoverable via a DSM surcharge since 1994, when the General Assembly enacted KRS 278.285.

Having made these points, it is not our intent to imply that regulation should stand still. There clearly is greater uncertainty today than in the past and we would be remiss in our responsibility if we did not seek ways to improve on the existing practices and procedures employed by the Commission. Securitization, an issue raised by KIUC, is something we believe merits further consideration. We also believe that the issue raised by Meade County RECC concerning the operation of our CPCN process for distribution cooperatives is a matter that should be taken under advisement.

The issues raised by Alcan and Century are both serious and complex. It is true that competitive energy markets have not evolved as Alcan and Century expected. It appears that the discussion in this case of how the smelter loads will be served beyond the expiration dates of their existing contracts has merely scratched the surface of the issues that could impact how this matter may be resolved. We believe that this issue will require further detailed review by numerous parties, including the Commission, the smelters, Big Rivers, Kenergy, LG&E Energy as lessee of Big Rivers' generation, and representatives of the state and local governments.

The regulatory scheme in Kentucky has been successful due in part to the measured and deliberate approach that has been taken to address various issues.

Conclusion

As previously noted, Kentucky's electric utilities, both jurisdictional and non-jurisdictional, currently either have adequate generation, transmission and distribution to serve their customers, or are actively working to meet customers' needs. Moreover, Kentucky's utilities have demonstrated that they are adequately planning to serve the needs of their customers through 2025. Given the absence of identifiable benefits to "restructuring" or "deregulating" Kentucky's electric utility industry at this time, the Commission concludes that Kentucky should preserve its current statutory and regulatory framework, which focuses primarily on the utilities' obligation to serve the electrical needs of customers within a defined service territory.

Within the current framework, however, there are no guarantees that future electricity prices in Kentucky will continue to be the lowest in the nation. The current fleet of coal-fired electric power plants in Kentucky accounts for much of our low-cost power. Portions of this fleet are aging and subject to future environmental restrictions. As aging infrastructure is replaced, new costs will have to be paid by Kentucky ratepayers.

Assuming FERC and the congress continue to promote the development of regional wholesale electricity markets, Kentucky must work to ensure that the interests of Kentucky's ratepayers and utilities are represented. This is true for other federal policy developments, such as environmental and eminent domain issues, which will affect Kentucky's future electricity prices and availability.

Because the U.S. electric power industry is changing, Kentucky should consider policies to protect or insulate Kentucky ratepayers from market uncertainties and the price implications of future environmental restrictions. On the other hand, given the economic benefits of Kentucky growing as an energy exporter, policy makers should also give consideration to opportunities for Kentucky citizens, businesses, and communities to benefit from greater participation in energy markets. In either case, a balanced approach will be necessary to preserve Kentucky's low-cost energy, responsibly develop Kentucky's energy resources, and preserve Kentucky's commitment to environmental quality.

Among the immediate uncertainties facing the electric power industry in Kentucky are: federal policies regarding the development of regional electricity markets and air emission standards; ability to site new electric generation and transmission facilities; factors affecting coal production and the price of coal; and technologies that will improve the efficiency of electricity production and use. Policy and technological developments with regard to these issues will directly affect electricity rates in Kentucky. Given the importance of low electricity rates for Kentucky, both as a tool for recruiting and retaining businesses, as equally as a necessity for all its citizens, the Commonwealth must continually evaluate its policies to mitigate the risks associated with generating, transmitting and distributing electricity.

GLOSSARY OF TERMS AND ACRONYMS

AEP-East	A power pool – part of American Electric Power, that presently consists of five utilities operating in seven Midwestern states
Ancillary services	Those services necessary to support the transmission of energy and to maintain reliability, including voltage control, generation operating reserves and load balancing.
Baseload	The minimum amount of electric power delivered or required over a given period of time at a steady rate within a service territory.
Baseload generation, or baseload capacity	The generating equipment normally operated to serve loads on an around-the-clock basis.
Baseload plant	Power plant that typically uses low-cost fuel, allowing utilities to economically use that equipment a high percentage of the time. They typically have higher installation costs, but usually a lower overall cost of energy if used a high percentage of the time.
Big Rivers	Big Rivers Electric Corporation
Bulk power	Wholesale power transferred in large quantity across high voltage lines.
Bundled Services	Combining all costs into one rate, as opposed to separate charges for generation, transmission and energy services.
CAIR	Clean Air Interstate Rule; Pollution Reduction Strategy targeting the reduction of SO_2 and NOx.
CAIDI	Customer Average Interruption Duration Index; A distribution Reliability measure that represents the average time to restore service.
Capacity	The limit at which a generator, turbine, transformer, transmission circuit, substation or system can produce or carry electricity for extended periods per manufacturers ratings.

CG&E	The Cincinnati Gas & Electric Company, the parent of The Union Light, Heat and Power Company
Cinergy	A public utility holding company - the parent of CG&E and Public Service Indiana.
Combustion turbines (CT)	An electric generator powered by gas or fuel oil, which often provides energy for peak loads. CTs typically have lower installation costs, but have higher fuel / operating costs.
Congestion	An overload condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously.
Control areas	An electric power system in which a common automatic control scheme is applied in order to maintain power supply and demand, maintain system frequency, and provide sufficient generating capacity to sustain sufficient operating reserves.
Cooperative (Co-op)	A not-for-profit electric utility that is owned by and operated for the benefit of those using its service. There are 24 rural electric cooperatives in Kentucky that are supported by two generation and transmission cooperatives, East Kentucky Power in Winchester and Big Rivers Electric in Henderson, and TVA.
Demand Side Management (DSM)	Utility sponsored programs that influence the amount or timing of a customer's energy use. The use of management tools, such as conservation programs or incentives for reducing demand, that lower the demand for power during certain times of the day or week, or that shift the demand to times when demand is lower.
Demand	The rate at which electric energy is delivered to or by a system at a given instant or over a designated period of time.
Deregulation	Also called restructuring. The reorganization of traditional electric service to allow charges to be separated or "unbundled" into generation, transmission, distribution and other services. This may allow customers to buy electric service from competing providers at both the wholesale and retail levels.
Distribution system	The portion of an electric system that delivers electric energy to an end-user through low-voltage lines.
Diversity Exchange	An exchange of capacity or energy, or both, between electric systems whose peak loads occur at different times.

East Central Area Reliability Coordination Agreement (ECAR)	One of 10 regional reliability councils that comprise the North American Electric Reliability Council (NERC). It is charged with promoting the reliability and adequacy of power supply in its area. All Kentucky transmission-owning utilities are members of ECAR with the exception of TVA, which is a member of the Southeast Area Reliability Council (SERC).
East Kentucky Power	East Kentucky Power Cooperative, Inc.
Economy transactions	The purchase of power when it is less expensive than one's own generation, for a limited duration. This power is typically provided on an interruptible basis.
EEI	Electric Energy Inc.
EHV	Extra High Voltage
EIA	Energy Information Agency
Embedded costs	The cost of the existing electric system that is reflected in a utility's rate base.
End-use customer	A residential, commercial, agricultural or industrial customer who buys electricity to be consumed as a final product (not for resale).
Energy Board	Kentucky State Energy Policy Advisory Board
Exempt Wholesale Generator(EWG)	An independent, unregulated company that generates power solely for wholesale use and not to the public. Created by the Energy Policy Act of 1992.
Federal Energy Regulatory Commission (FERC)	An independent regulatory agency within the U.S. Department of Energy that has jurisdiction over rates, terms and conditions of the transmission and wholesale sale of electricity between states.
FERC Order 888	Regulations issued by FERC that encourage wholesale competition in electricity by requiring transmission owners to permit other parties to utilize the existing system to transfer wholesale generated electricity to end-users.
FERC Order 889	Regulations issued by FERC which require transmission system owners to make the terms and conditions of transmission services available to the public at the same time that the information is available to the transmission system owners' generating and power trading business units and its affiliates.

FERC Order 2000	This 1999 order urged utilities with transmission to place their systems under the operational control of independent Regional Transmission Organizations (RTO).
Firm power	Power intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.
Firm transmission service	Transmission service that has the highest priority. Long-term firm transmission service has the same priority as that of the transmission provider's own use of the transmission system.
Franchise customer, native load customer	The wholesale and retail end-users a provider is obligated to serve within its franchised service territory.
Generation	The process of producing electrical energy.
Generator	A machine that converts mechanical energy into electrical energy.
Generation and transmission cooperative (G & T)	Not-for-profit organization that generates and transmits energy to distribution systems. The distribution system, which sells energy to retail end-users, owns the G & T.
Grid	An electric system linking transmission lines, both regionally and locally.
Hydroelectric plant (Hydro)	A power plant in which turbine generators are driven by falling water.
IGCC	Integrated Gasification Combined Cycle; Clean coal technology aimed at meeting environmental goals by joining coal gasification and combined cycle to maximize energy output.
Independent Power Producer (IPP)	An unregulated private entity that generates electricity and sells wholesale power to brokers and utilities.
Independent System Operator (ISO)	An independent, federally-regulated entity that coordinates regional transmission in a non-discriminatory manner and ensures the safety and reliability of the electric system.

Interruptible power	A special contract or tariff given to certain industrial customers that agree to have their service curtailed or temporarily suspended as part of an agreement with their electric provider.
Investor-owned utility (IOU)	An electric utility company owned and operated by private investors or stockholders. IOUs in Kentucky are Louisville Gas & Electric; Kentucky Utilities; The Union Light, Heat and Power Company, a subsidiary of Cinergy; and Kentucky Power Company, a.k.a. American Electric Power.
IRP	Integrated Resource Plan – A written plan that demonstrates an electric utility's forecast of future demand and its plans for acquiring the resources necessary to reliably meet that demand at the lowest reasonable cost consistent with good utility practices.
Kilowatt (kW)	One thousand watts. The standard measure of electrical flow or power. Enough electricity to power ten 100-watt light bulbs.
KPE	Kentucky Pioneer Energy
Kenergy	Kenergy Corporation
KU	Kentucky Utilities Company. An affiliate of LG&E owned by LG&E Energy.
LEM	LG&E Energy Marketing, Inc.; an unregulated affiliate of LG&E.
LG&E	Louisville Gas & Electric Company an affiliate of KU owned by LG&E Energy.
Load	The amount of electric power required to meet customer's use in a given time period.
Load diversity	Reflects the fact that customers' electricity usage varies, depending upon the time of day, season, etc.
Market prices, market-based rates	A price set by the competitive market.
Megawatt (MW)	One million watts. This term is generally used to measure the flows or capacity of power plants and transmission lines.
MEPAK	Municipal Electric Power Association of Kentucky

Merchant plant	A power plant built not to serve a geographic region but to sell bulk power to brokers and utilities, without its output necessarily being committed to long-term power contracts.
M ISO	Midwest Independent System Operator an RTO whose Kentucky members include KU, LG&E and ULH&P.
Municipal utility	A not-for-profit utility owned and operated by a municipal government in the community it serves. Municipal utilities serve Frankfort, Bowling Green, Owensboro and Bardstown, among other cities in Kentucky.
Native load	The end-user electrical demand in a utility's service territory. For a G & T cooperative, the electric demand in its member distribution cooperatives' service territories.
North American Electric Reliability Council (NERC)	A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America.
Obligation to serve	The regulatory obligation of a utility to provide electric service to any customer who seeks that service, and is willing to pay the rates for that service.
Off-system sale	Energy supplied outside a utility's service territory. For a G & T cooperative, energy supplied outside its member distribution cooperatives' service territories.
Open access	A regulatory mandate that allows others to use a utility's transmission and distribution facilities to move bulk power from one point to another on a nondiscriminatory basis for a cost-based fee.
Outage	The period during which a generating unit, transmission line, or other facility is out of service.
OVEC	Ohio Valley Electric Corporation
PJM	PJM Interconnection, LLC. An RTO of which Kentucky Power is a member.
Peak demand	The maximum load during a specified period of time.
Peaking unit	Generating equipment normally reserved for elevated demand during the hours of the highest daily, weekly or seasonal loads.

Power marketer	An entity that takes title to electric power and then resells power to end-use customers.
Provider of last resort	A legal obligation to make service available to an end-user within a providers service territory.
Rate base	The amount of money a regulated public utility has invested over the years in facilities (net of depreciation) which serves the customers, plus the amount of working capital required to cover the company's operating and maintenance expenses. The cost of plant, property and equipment which regulators allow regulated public utilities to recover through consumer rates.
Regional Transmission Organization (RTO)	A utility industry concept that the Federal Energy Regulatory Commission embraced for the certification of a regional organization that would be responsible for transmission planning and use on a regional basis. MISO and PJM are the two RTOs with Kentucky members.
Reliability	Electric system reliability has two components—adequacy and security. Adequacy is the ability of the electric system to supply to aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities.
Reserve margin	The amount of unused available capability of an electric power system for a utility system at peak load as a percentage of total capability.
Restructuring	See deregulation.
Return on equity (ROE) component	The financial return on investment that regulatory authorities allow investor-owned utilities.
SAIDI	System Average Interruption Duration Index; A distribution reliability index that indicates the duration of interruption for an average customer.
SAIFI	System Average Interruption Frequency Index; A distribution reliability measure that represents how often an average customer experiences a sustained interruption.

Selective Catalytic Reduction (SCR)	Equipment used to remove nitrous oxides from boiler plant combustion gases prior to atmospheric discharge.
SEPA	Southeast Power Administration
Substation	Equipment that switches, changes or regulates electric voltage.
Stranded costs	Prudent costs incurred by a utility, which may not be recoverable under market-based retail competition. Examples are un-depreciated generating facilities, deferred costs, and long-term contract costs.
Tariff	A document that lists the terms, conditions and prices under which utility services – approved by a regulatory agency - will be provided.
Tennessee Valley Authority (TVA)	A federal corporation and the country's largest public power company, serving Tennessee and portions of six other states, including several counties in south central and western Kentucky.
TLR	Transmission Loading Relief. A process controlled by system operators to relieve transmission congestion by re-routing power flow within an existing grid.
Transmission	The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. .
Transmitting utility	Any utility transmitting wholesale, high-voltage electrical energy. A transmitting utility can be for-profit, or in the case of cooperatives, not-for-profit.
Unbundled rates or service	Electric service broken down into its basic components. Each component is priced and sold separately. For example, generation, transmission and distribution could be unbundled.
Wholesale transactions	The purchase and sale of electricity from generators to organizations that sell to retail customers.

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The Impact of Federal and International Policy on Kentucky's Energy Future

A Review Conducted
Pursuant to
Executive Order 2005-120

by the
Kentucky Public Service Commission

August 22, 2005

Kentucky
UNBRIDLED SPIRIT

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INTRODUCTION

Executive Order 2005-120, issued by Governor Ernie Fletcher on February 7, 2005, directed the Kentucky Public Service Commission ("Commission") to "consider, investigate, and issue a report related to the role of the federal government and international institutions as they might bear on an energy policy for the Commonwealth of Kentucky." Further, the Executive Order stated that "The Report shall identify federal and international policies or actions that affect the ability of the PSC to establish in Kentucky electric and natural gas rates that are fair, just and reasonable. The report shall also identify how such policies or actions affect the ability of Kentucky based energy producers to export energy supplies in interstate and international markets."

In accordance with the Executive Order, the Commission conducted a comprehensive review of relevant statutes, treaties, and other source materials. This report summarizes the jurisdiction of federal government agencies and the Commission with respect to electricity and natural gas utilities and services, and the effect of recent federal statutory and regulatory changes on Kentucky's energy policy and the ability of the Commission to ensure fair, just, and reasonable utility rates for Kentuckians. The findings and conclusions of this report are based upon years of Commission expertise in regulating utilities within its jurisdiction and participating on behalf of the Commonwealth in federal regulatory proceedings, particularly at the Federal Energy Regulatory Commission ("FERC"). The statements contained in this report are intended as general observations, and are not binding on the Commission in any pending or future proceeding.

Lastly, the role of the federal government and relevant international institutions is a fluid one. Consequently, this report reflects the status quo. Many relevant issues are presently before the courts, at the FERC and other federal agencies, and part of the World Trade Organization's ("WTO") ongoing negotiations regarding the General Agreement in Trade and Services ("GATS"). Moreover, the provisions of the Barton-Domenici Energy Policy Act of 2005, enacted on August 8, 2005, will be implemented over the coming years and will undoubtedly affect energy prices and utility rates in Kentucky. Where possible, this report attempts to summarize the potential effects of this legislation.

EXECUTIVE SUMMARY

Kentucky enjoys abundant supplies of affordable energy in the form of electricity and natural gas. Kentucky consumers, on average, pay the lowest electricity rates in the nation, while our natural gas rates are slightly below the national average. The wholesale price of natural gas is established by mature, interstate commodities markets regulated by the federal government and is passed through to consumers in the rates of distribution utilities. Interstate electricity markets and electric utility service are undergoing a period of rapid change and subject to both federal and state regulation.

The price Kentuckians pay for natural gas is largely determined by federal policies affecting supply, demand, and deliverability. Initiatives to increase the availability of natural gas, in the form of new production and infrastructure, will benefit Kentucky ratepayers. As for electricity, Kentucky (unlike some states) closely regulates all aspects of electricity price and service to customers, whereas the federal government regulates the price and terms of service for bulk power sales to other utilities. Kentucky's extremely low electricity rates are the result of historic investments by Kentucky's utilities in large, coal-fired generating units, along with an abundant local fuel supply, sound utility management, and careful regulation. Federal policies regarding interstate wholesale power markets and environmental regulations will affect the price of electricity in Kentucky. Kentucky should consider appropriate policies to mitigate these risks.

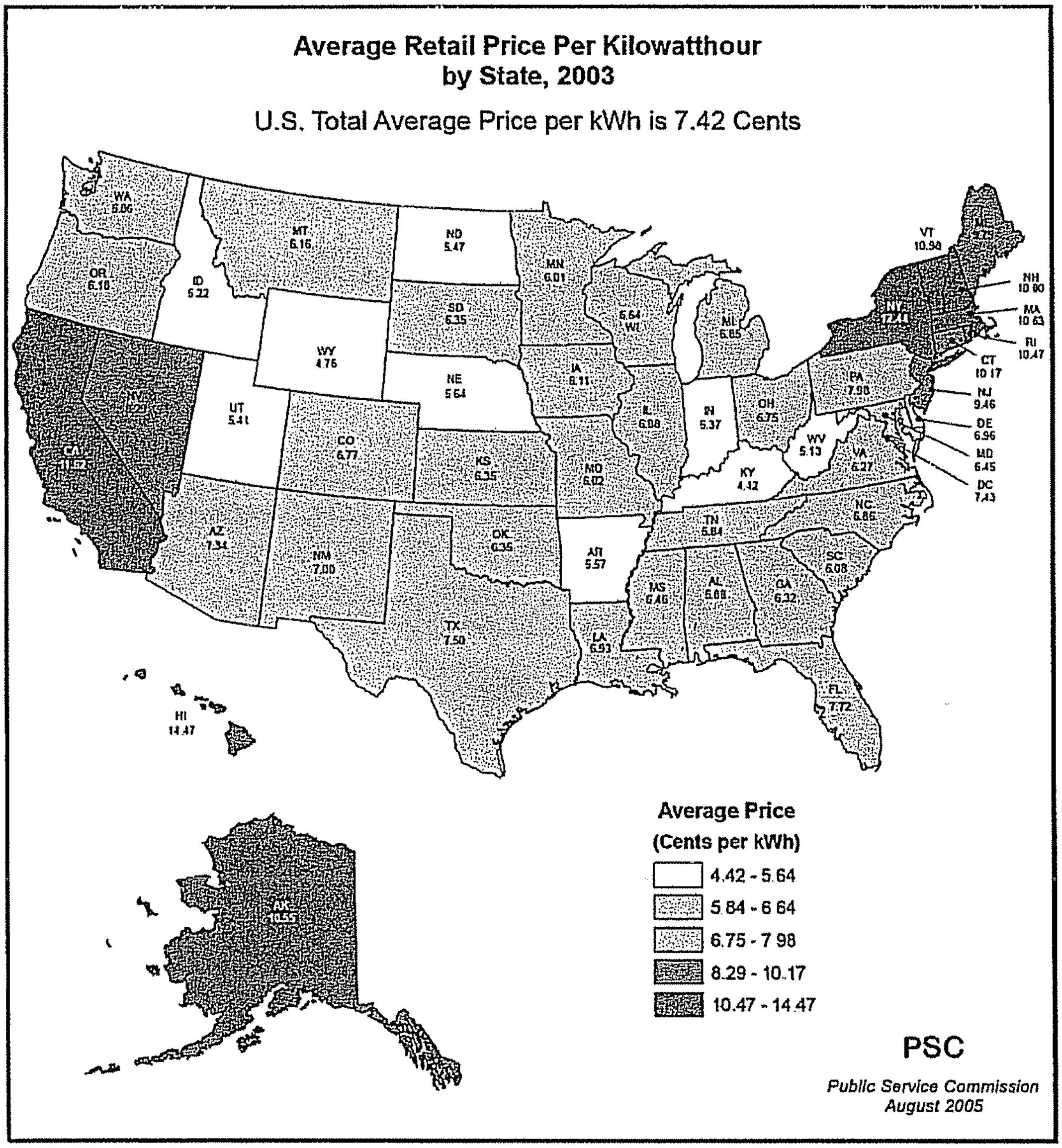
On August 8, 2005, the President signed into law H.R. 6, the Barton-Domenici Energy Policy Act of 2005. In the Comprehensive Energy Bill just passed by Congress, contained in the voluminous Act are noteworthy changes to federal electricity and natural gas laws. The provisions of the Act, which include clarification of FERC jurisdiction with regard to interstate markets and RTOs along with economic incentives and tax reforms, are designed to improve electric reliability and spur investment in electricity and natural gas infrastructure. The new law also contains a number of tax reforms that may affect electricity and natural gas prices. Specifically, the Act amends the Internal Revenue Code to assign a seven-year depreciation recovery period to natural gas gathering lines; assigns a fifteen-years depreciation recovery period to natural gas distribution lines and certain electric transmission properties; expands the amortization period for certain pollution control facilities; and exempts certain prepayments of natural gas from arbitrage bond rules. Lastly, the new Act contains a number of provisions designed to improve our Nation's energy efficiency, which will help reduce future prices for electricity and natural gas. Among the provisions are efficiency standards for new products and appliances, new energy efficiency requirements for the Federal government, and a tax credit up to $2000 per year for 20% of expenditures for energy efficiency improvements made to existing residences before 2008.

Recent developments in international trade law do not appear to pose a threat to Kentucky energy prices and supplies. However, treaties potentially affecting international energy markets should be monitored carefully.

ELECTRICITY ISSUES

Kentucky currently is in an enviable position, enjoying the lowest retail electricity rates in the country. The reasons for Kentucky's low rates are varied, but primarily they derive from historic investments by utilities in large, coal-fired generating units, combined with an abundant local fuel supply, sound utility management, and a statutory system that ties the price utilities may charge for providing electricity service to the costs of providing that service. By and large, electric utilities in Kentucky are healthy and able to meet the needs of customers with their own generation or through long-term power supply contracts. Although interstate wholesale electricity markets are developing in states and regions to the east, north, and west of Kentucky, utilities in Kentucky are rarely dependent on these markets to meet their daily electricity supply needs.

Overall, Kentucky is a net electricity exporter. Anticipated profits from the sale of surplus power by Kentucky's regulated utilities to other utilities are typically factored into the retail electricity rates of their customers. Profits derived from these "off-system" sales are used to offset other operational and capital costs paid by Kentucky ratepayers. However, too much capacity may result in excessive costs that cannot be offset by off-system sales. Kentucky's jurisdictional electric utilities do not typically plan for a significant level of such sales. Generally, Kentucky's utilities plan generation resources to meet their native load and have a reasonable reserve margin. If Kentucky's utilities do

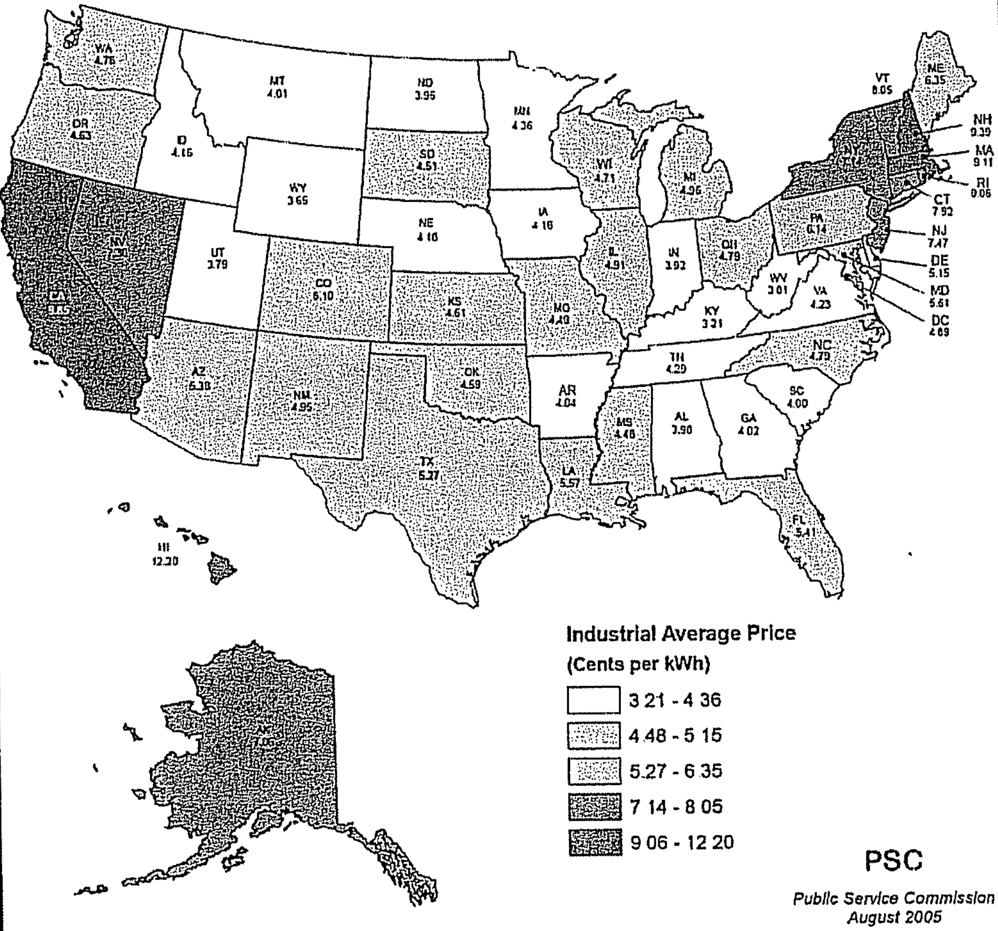


Source: Energy Information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Data".

Figure 1. Average Retail Electricity Rates

U.S. Electric Power Industrial Average Retail Price per Kilowatthour by State, 2003

U.S. Industrial Average Price per kWh is 5.13 Cents



Source: Energy Information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Data".

Figure 2. Average Industrial Electricity Rates

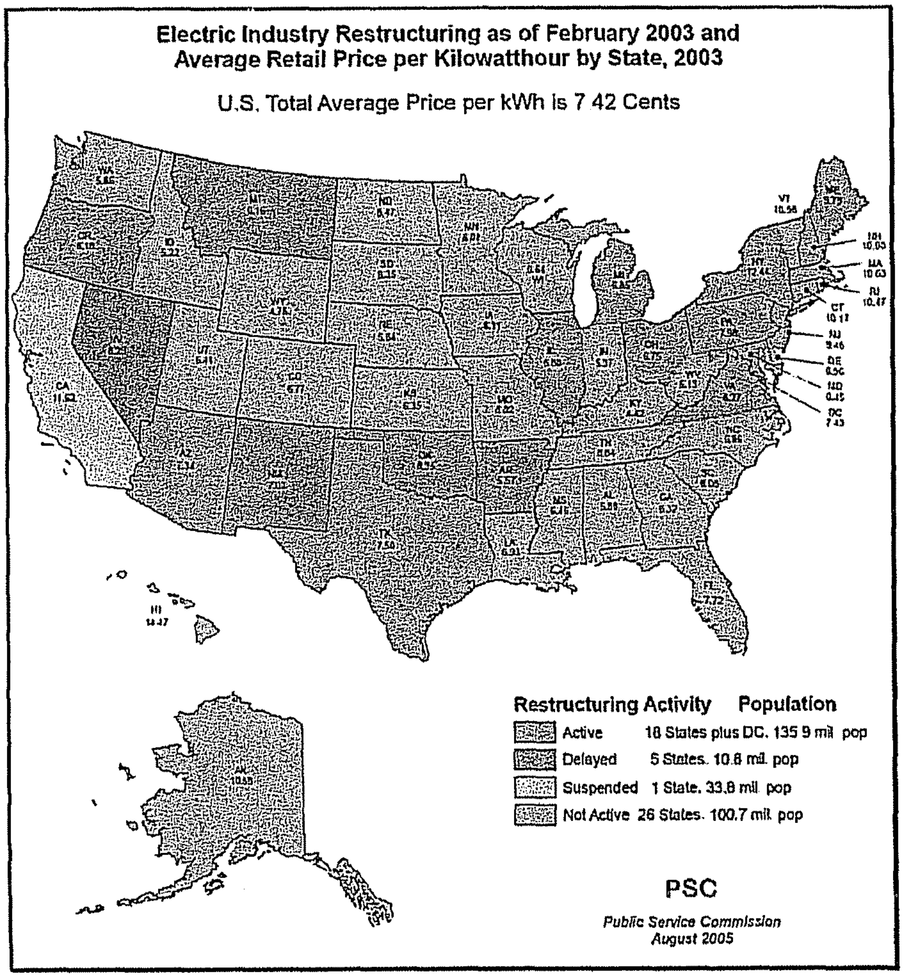
not continue to balance generation capacity with demand, the resource imbalance will require Kentucky's utilities to rely on the wholesale energy market to either sell excess generation or to purchase additional supply resources at competitive market prices.

History of Electricity of Production

To better understand the outside forces that impact Kentucky's ability to retain low cost electricity while benefiting from off-system sales, it is necessary to review the history of how utility regulation has evolved.

Traditionally, in Kentucky and across the country, an electric utility provided all functions to its customers: generation, transmission, distribution and marketing. These utilities are referred to as "vertically integrated utilities" and are regulated as natural monopolies. State public utility commissions ("PUCs") or public service commissions ("PSCs") have historically determined where these utilities can operate, which facilities they can construct, what services they provide and what rates they charge their customers. Traditionally, these rates have been based upon the utilities' costs—both for capital infrastructure investments and the costs of operating, maintaining, and providing utility service. Regulation of electric utilities in Kentucky follows this traditional regulatory model.

In recent years, a number of states have attempted to "restructure" or "de-regulate" their electric utility industry. The formula varies from state to state, but the central concept is more or less the same: by statute or regulation, customers are given the ability to choose their electricity supplier; outside suppliers (other utilities or marketers) and incumbent utilities are authorized to contract with customers to supply power; incumbent utilities continue to "deliver" or distribute the power to the customer; "market power" is mitigated by regulation and/or requiring divestiture of the incumbent utility's generating capacity; charges are imposed to allow the incumbent utility to recover previously-allowed, but now "stranded" costs; and mechanisms, such as rate freezes and suppliers-of-last-resort, are put in place to facilitate the transition to a "competitive" retail electricity market. Typically, "restructuring" has occurred in states with historically high electricity rates—the premise being that competitive forces will result in lower electricity rates. States pursuing restructuring have met with varying degrees of success, with California experiencing the most dramatic problems, and Pennsylvania often viewed as one of the most successful. One of the benefits of competitive markets touted by proponents is that investors, rather than ratepayers, bear the risk for bad investments. Detractors, however, point out that because of the natural monopoly characteristics of electricity generation, transmission and distribution; markets do a poor job of ensuring sufficient generating supply margins to meet electrical reliability needs. This is due to the seasonal nature of electricity demand and the high capital cost (hundreds of millions of dollars) of base load power plants.



"Active" States have either enacted enabling legislation or issued a regulatory order to implement retail access. Retail access is either currently available to all or some customers or will soon be available In Oregon, no customers are currently participating in the State's retail access program, but the law allows nonresidential customers access

"Delayed" States have either delayed the restructuring process or the implementation of retail access.

"Suspended" State (CA) has ordered suspension of direct retail access

"Not Active" States are not actively pursuing restructuring

Sources:
1. *Energy Information Administration, U.S. Dept. of Energy, webpage: www.eia.doe.gov. "Status of State Electric Industry Restructuring Activity as of February 2003"*
2. *Energy Information Administration, U.S. Dept. of Energy, Form EIA-826. "Monthly Electric Utility Sales and Revenue Data"*
3. *U.S. Department of Commerce, Census Bureau. Table 2: "Resident Population of the 50 States, the District of Columbia, and Puerto Rico: Census 2000," December 2000 release.*

Figure 3. Electric Industry Restructuring Activity

In Kentucky, six major electric utilities are regulated by the Commission. Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") are investor-owned utilities ("IOU's") that operate primarily in Kentucky, while Kentucky Power Company, a subsidiary of American Electric Power ("AEP") and The Union Light, Heat and Power Company ("ULH&P"), a subsidiary of Cinergy, are IOU's that are part of multi-state holding companies. East Kentucky Power Cooperative ("EKPC") and Big Rivers Electric Cooperative ("BREC") are non-profit generation and transmission cooperatives. The Commission also regulates distribution cooperatives, but does not regulate municipal electric utility systems, or the Tennessee Valley Authority ("TVA") or its distribution utilities. The Commission has no jurisdiction over electric power sales by Independent Power Producers ("IPPs") (often referred to as merchant generators or merchant plants) that generate electricity for sale to other utilities or in the wholesale market. However, the Kentucky State Board on Electric Generation and Transmission Siting regulates the siting of IPPs and merchant transmission lines (i.e., those transmission lines proposed to be built in Kentucky by entities not regulated by the Commission).

Federal Regulation of Electricity

Just as the state PUCs and PSCs have traditionally regulated the retail operations of utilities within their borders, the FERC has jurisdiction over and responsibility for regulation of: (1) wholesale electric power sales, (2) interstate transmission rates, (3) mergers and acquisitions of utility companies and certain facilities, and (4) hydroelectric power projects. In addition to FERC regulation, utilities also are regulated by other federal entities, such as the Federal Trade Commission ("FTC") and/or the Department of Justice ("DOJ"), with regard to anti-trust matters. Under the Public Utility Holding Company Act ("PUHCA") and other securities law, electric utilities and their holding companies are also regulated by the Securities and Exchange Commission ("SEC"). Note, however, that the recently enacted Barton-Domenici Energy Policy Act of 2005 repeals PUHCA and expands FERC jurisdiction to include review of holding company mergers and acquisition by utilities of power plants. Finally, the other major federal regulatory agencies impacting the utility industry are the Department of Energy ("DOE"), especially in manners dealing with energy infrastructure security coordination, research and development, and the Environmental Protection Agency ("EPA") with regard to compliance with environmental laws.

Historically, the Federal Power Act of 1935 gave the Federal Power Commission (now known as FERC) jurisdiction over interstate electricity service of "public utilities" while leaving intrastate and retail electricity regulation to individual states. At that time, electricity generation service was provided by vertically integrated utilities operating as regulated monopolies, which were only allowed to charge cost-based rates, including cost-based sales of power to other utilities. Over time, FERC began allowing utilities to charge "market-based" rates for sales from one utility to another (wholesale transactions). FERC only allows utilities to charge market-based rates if the utility has demonstrated that it does not possess undue market power (i.e., the ability to artificially manipulate the wholesale price of power). FERC has limited jurisdiction over the rates and terms of service of cooperatively-owned utilities, municipal electric utilities, and federally-owned utilities, such as TVA and the Power Marketing Administrations.

In 1935, PUHCA gave regulation of utility holding companies to the SEC. In 1978, The Public Utility Regulatory Policies Act ("PURPA") established a class of non-utility generators referred to as qualifying facilities ("QFs"). Utilities were required to connect QFs and buy power at prices not to exceed the avoided cost of generating that power themselves. The intent of this legislation was to encourage small renewable generators and cogeneration (the production of electricity and another form of useful energy such as heat or steam). Indirectly, this led to a new class of independent power producers, and set a precedent for utilities being required to interconnect to non-utility generators.

In 1992, the Energy Policy Act ("EPAct") established a new category of non-utility generators, exempt wholesale generators ("EWGs"). (*Exempt* refers to their exemption from holding company provisions of PUHCA). The EPAct expanded the Federal Power Act by authorizing FERC to require utilities to transmit or "wheel" other suppliers' power across their transmission systems. FERC implemented this open access requirement in Orders 888 and 889 in 1996, which was intended to prevent utilities from discriminating against other suppliers when providing access to transmission service. Order 888 also introduced the concept of an Independent System Operator ("ISO"), which is an independent entity that would operate transmission systems to ensure that utilities provide for open access to their transmission systems. In December 1999, FERC issued Order 2000, which outlined minimum functions of a Regional Transmission Operators ("RTOs") (very similar to ISOs) and required utilities to file a proposal to join or form an RTO. RTOs are regional entities responsible for providing transmission services and ensuring open access to the transmission system of multiple utilities. While Order 2000 required utilities to file their intentions to join an RTO, FERC did not explicitly mandate that utilities join an RTO.

Originally intended to implement open access requirements, RTOs have evolved into also serving as trading platforms for wholesale electricity markets. Two RTOs have members in Kentucky: the Midwest Independent Transmission System Operator ("MISO"), of which ULH&P (through its parent company Cinergy) and LG&E/KU are members; and PJM Interconnection, Inc. ("PJM"), of which Kentucky Power ("AEP") is a member. However, the Commission currently has an open investigation of LG&E and KU's membership in MISO. MISO and PJM are not only providing those services outlined in Order 2000 (primarily ensuring non-discriminatory access and scheduling transmission on the bulk power system), but are also running FERC-approved regional wholesale electricity markets, with day ahead and real time markets for power.

With the passage of the EPAct in 1992 and subsequent FERC Orders aimed at developing regional wholesale power markets, the line of demarcation between state and federal regulation has been shifting. Similarly, the role of the state PUCs and PSCs has been changing. Roughly half of the states have, in some fashion, restructured their electricity service to provide for retail access to competitive electricity providers in an effort to take advantage of lower priced electricity available in the wholesale market. These states have increased their reliance on the wholesale market and therefore RTOs to facilitate delivery of bulk power to utilities. The PSCs or PUCs in these states have shifted their regulatory focus toward retail market oversight, and rely on FERC for oversight of wholesale markets. Although several of Kentucky's utilities are members of RTOs, the Commission continues to regulate these utilities under a traditional model, which focuses on ensuring that each utility is able to meet its supply needs through self-generating power from plants they own or by entering into long-term power supply contracts.

A more recent effort by FERC to promote development of interstate electricity markets was the Standard Market Design ("SMD") Order, issued on July 31, 2002, which proposed to strengthen and expand the RTO model. SMD would have mandated that utilities give up control of their transmission systems by either joining an RTO or employing an independent operator. The proposed order set forth a specific vision for the development of regional electricity markets and proposed extensive changes to the calculation of interstate transmission rates, the rules governing interstate electricity markets, and utility resource planning. In the face of significant opposition from utilities and states, FERC attempted to soften the proposed changes with the issuance of the SMD White Paper in April of 2003, which modified the original proposals and further discussed FERC's rationel. Under new leadership and in the face of continued opposition (as manifested in the electricity title of the recently enacted federal energy bill), FERC has suspended work on SMD, formally terminating the proceeding on July 19, 2005. However, portions of FERC's proposed SMD have already been adopted by MISO and PJM and Kentucky's retail customers are impacted as a result.

Regional Transmission Organizations

In the stakeholder forums at MISO and PJM, as well as at the FERC, the Commission finds itself in the minority when positions are taken and policies implemented that place a burden or an additional cost on Kentucky ratepayers while benefiting those who rely more heavily on wholesale markets. In multiple filings at FERC, the Commission has repeatedly outlined its concerns with the cost implications of RTOs and the encroachment upon state jurisdiction. In summary, these concerns revolve around the increasing costs of RTOs and the blurring of the distinction between state and federal responsibility for electricity service.

The costs associated with RTOs are recovered in wholesale transmission rates or other fees approved by FERC. Under the "filed rate doctrine," because these costs are lawfully established under federal law, a state must allow them to be passed through in utility rates. In Kentucky, these costs must be paid by the utility's "native load" customers, i.e., those customers historically served by the utility at rates designed to reflect the cost of the utility's system plus a return on investment. Since Kentucky's utilities traditionally self-generate or otherwise procure their own electricity supplies, delivering that electricity over their own transmission facilities, by paying RTO-related costs, native load customers are being asked to pay for a service for which they may receive limited benefits. From Kentucky's perspective, if one only looks at the issue of purchasing wholesale power to meet the power demands of our largest utilities, there is little obvious economic benefit to utilities in Kentucky of participating in RTOs. However, utilities may be able to recoup the costs by increasing their "off system" sales as a result of RTO membership. Unless our large utilities are able to purchase power from another supplier for less than the cost at any given time of self-generating power, they can and should generate that power themselves.

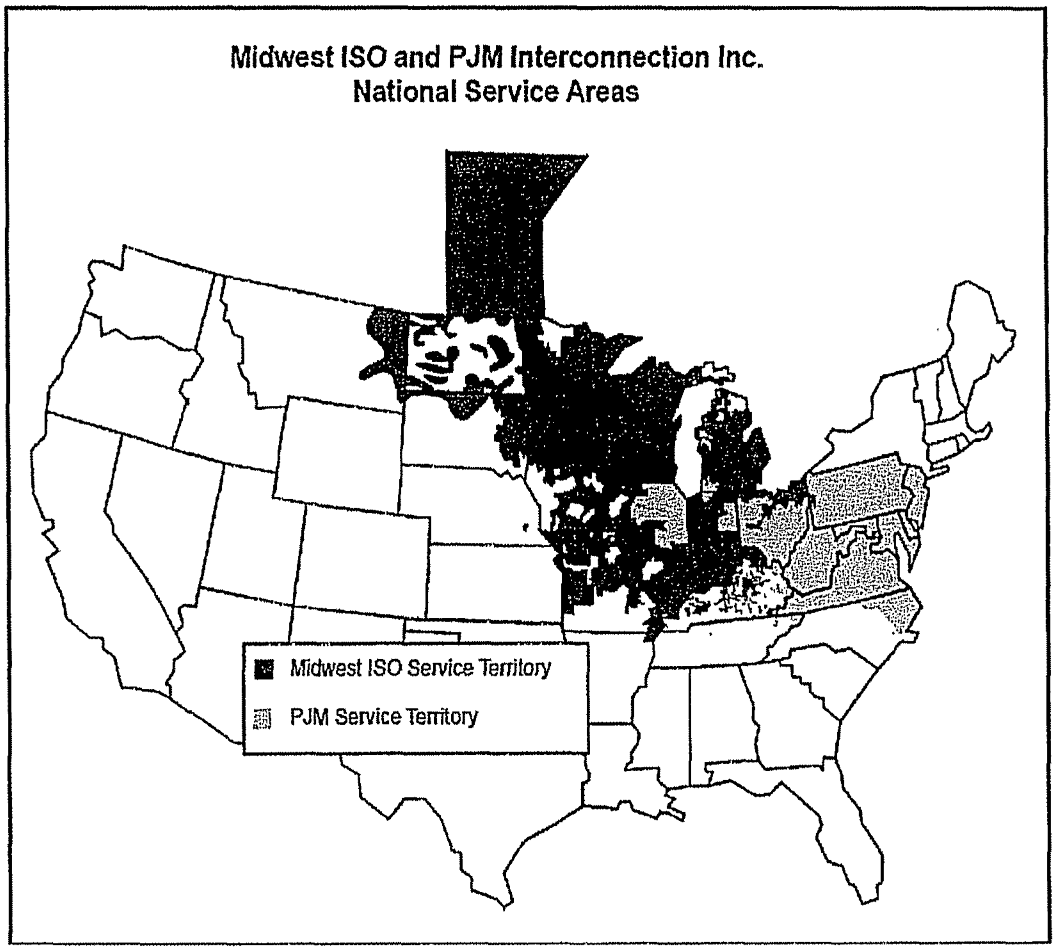


Figure 4. MISO and PJM Footprints

Another major area of concern is the increasing scope of RTOs and blurring of the line between FERC-regulated functions and state-regulated functions. Of particular concern are issues involving generation adequacy and the allocation of costs associated with transmission upgrades. The Commission, through its Integrated Resource Planning ("IRP") process, ensures that the utilities are forward looking and have plans in place to meet native load growth. To obtain a Certificate of Public Convenience and Necessity ("CPCN") to construct any facilities or power plants, utilities must show that the facility is necessary to meet the needs of its customers and is the best alternative available considering cost and all other relevant factors. Kentucky's utilities would not be able to obtain a CPCN for investment beyond that needed to serve their native load customers. Though not certain at this time, there are proposals at both PJM and MISO to look at generation resources from a regional perspective. Some argue that this could lead to requirements for Kentucky's utilities to build generation that is needed regionally, but not needed to serve Kentucky's native load customers.

For example, at both PJM and MISO there are regional planning efforts to identify needed transmission upgrades. It is not clear at this time how the costs of any upgrades in Kentucky would be allocated. Naturally, Kentucky ratepayers should only pay their share of any cost associated with upgrade of transmission lines to the extent they benefit. The difficulty in assigning costs to those that benefit is in determining who benefits and by how much. FERC has taken the perspective, broadly stated, that expansion of electric infrastructure makes the interstate system more robust and therefore benefits all users of the grid. Many states argue that projects designed to facilitate long-distance transfers of power should not be paid for by local ratepayers. While lines built to facilitate interstate transfers of electricity would provide a marginal benefit to Kentucky's native load customers, they may not be necessary to serve them. Of the numerous recently proposed transmission expansion projects in Kentucky, all are seeking to be justified on the basis of meeting the growing electricity needs of Kentucky native load customers.

Proponents of RTOs argue that there are other factors that affect the wholesale price of power, such as deliverability, and other important benefits of RTOs, such as increased reliability, clearer market signals for investment in generation and transmission, and access to larger markets for utility sales of excess power. By having the ability to match buyers and sellers over a larger area, RTOs can schedule transactions and re-dispatch generators in order to relieve congestion on the grid. Proponents also point out the reliability benefits of RTOs. Since RTOs are responsible for monitoring the bulk transmission systems of multiple utilities, they are better able to detect and isolate incidents which could lead to widespread outages.

From an investor perspective, some analysts support RTOs because they are able to identify economic sites to construct regional infrastructure, such as merchant power plants and transmission lines. They argue that this also supports regional reliability by identifying weak points in the interstate system. From the perspective of traditional, vertically-integrated utilities, RTOs may also represent more robust markets for sales of surplus power. Given the rate structure of some utilities in Kentucky, which rewards customers by sharing a portion of the profits from such sales, RTOs may indeed benefit Kentuckians. Utilities that benefit from greater sales of surplus power, however, must be wary of market power issues at FERC. If a utility is determined to have undue market power, FERC may take away the utility's authority to sell wholesale power at market-based rates. One of the ways in which utilities have successfully shown mitigation of alleged market power is by having an independent entity controlling transmission services, such as an RTO.

ULH&P, a subsidiary of Cinergy Corp., and LG&E/KU are charter members of the MISO. As previously noted, the Commission is currently investigating the propriety of LG&E/KU's continued membership in MISO. In the case, LG&E/KU are asking that they be allowed to withdraw from MISO. Any withdrawal would have to be approved by FERC, and an exit fee paid, pursuant to the original agreement creating MISO. Among other arguments, LG&E/KU argue that the costs exceed benefits received, while MISO argues that the benefits outweigh the costs. The lengthy case file can be found on the Commission's Website, www.psc.ky.gov.

Kentucky Power, Kentucky's subsidiary of AEP is a member of PJM. PJM has grown quickly in budget, scope and geographic footprint as well. Given AEP's multi-state footprint and size, the Commission found that there were positive net benefits to membership in PJM, including opportunity for increased off system sales. However, AEP has expressed concern over the Resource

Adequacy model as proposed by PJM and its implications on its Kentucky operations.[1]

Kentucky's two generation and transmission ("G&T") cooperatives, BREC and EKPC, are not members of any RTO at this time. However, at the June 14, 2005 public hearing in the 2005-00090 case, the CEO of EKPC commented that their operations have been negatively impacted by the April 1, 2005 start-up of the MISO market. They commented that EKPC was being forced to run higher cost generation because of increased load on the transmission system.

In summary, Kentucky is in a unique place with respect to RTOs. Most of Kentucky's utilities are low-cost producers that do not rely on market purchases to meet their power needs. While there are significant costs associated with RTO participation, it is unclear to what extent the existence of organized markets, and Kentucky's participation in those markets, increases Kentucky ratepayers' ability to benefit from off-system sales. Any future restriction, however, on the ability of Kentucky's utilities to finance and construct new power plants to meet their future energy needs will necessitate a greater reliance on market-based purchases.

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[1] See written comments of Tim Mosher in PSC Case No. 2005-00090.

Barton-Domenici Energy Policy Act Electricity Provisions

Title XII, The Electric Reliability Act of 2005, is devoted to electricity. Among its significant changes to federal law are the following:

- Gives FERC authority to oversee the establishment of mandatory reliability standards for the electric power industry (Sec. 1201)
- Gives FERC limited "backstop" authority to site previously identified critical interstate transmission lines where states fail to take action (Sec. 1221)
- Establishes a new office and programs at the DOE devoted to electricity research and development (Sec. 1225-1227)
- Grants FERC limited jurisdiction over the transmission systems of non-jurisdictional utilities (co-ops, municipalities, etc.)(Sec. 1231)
- Expresses the sense of Congress that RTO participation should be voluntary (Sec. 1232)
- Remands FERC's proposed SMD Order and prevents any similar order until December 31, 2006 (Sec. 1235)
- Preserves the ability of traditional utilities to use their transmission to first meet "native load" customer needs, while preserving some current RTO policies (Sec. 1236)
- Directs FERC to establish "incentive rates" to reward investment in more efficient and beneficial transmission projects (Sec. 1241)
- Eliminates the mandatory purchase requirement of PURPA under certain conditions (Sec. 1253)
- PUHCA, gives states greater access to the books and records of holding companies, and expands FERC authority to review utility mergers and acquisitions (Sec. 1263-1276)
- Directs FERC to establish rules to facilitate more transparent markets, increases FERC penalty authority, and adds new consumer protections (Sec. 1281-1286)

How the changes to federal electricity law will affect Kentucky ratepayers is yet to be determined and will depend in large part on how the federal government implements the changes. For example, any cost incurred to comply with new reliability standards will likely be passed through to Kentucky ratepayers. However, the benefit of fewer outages and the savings derived therefrom will benefit ratepayers. It is unlikely that Kentucky will be affected in the short term by the expanded FERC "backstop" siting authority, since Kentucky law already provides a mechanism for timely consideration and permitting of proposed utility transmission projects. A conflict would arise if the federal government designated a "national interest electric transmission corridor," and utilities or merchants did not seek or were not granted a transmission certificate.

Based on engineering studies performed in 2001 and 2005, the Commission has concluded that there are transmission limitations to North and South power flows in Kentucky. MISO has reported similar findings. It is possible, therefore, that the DOE may designate Kentucky as having one or more "national interest electric transmission corridors." The concern would then be who pays for the designated transmission upgrades and how do state and local interested parties participate in siting the transmission line. It will be important for Kentucky to participate in any designation process at the DOE.

This raises another important issue, however, and that is the TVA "fence" which Kentucky straddles. Under federal law, TVA is prohibited from selling power outside of its territory, and other utilities are prohibited from selling to distributors within TVA. As a result, there are weak transmission interconnections between TVA and neighboring utilities in Kentucky limiting the North and South power flows mentioned above. It is unclear whether DOE would look to these weak points when considering national interest designations while the "fence" is still in place.

Taking down the "fence" will require changes in federal law, and such proposals have been put forth again recently. It is noteworthy that several Kentucky-based TVA distributors have given notice to TVA that they are leaving the TVA system and will be obtaining power from other suppliers at the end of five years. Transmission expansion in Kentucky may be required to facilitate this transition and better interconnect the former TVA distributors to Kentucky's jurisdictional utilities and outside suppliers. Any costs associated with supplying power to a former TVA cooperative will have to be recovered in the cooperative's Commission-approved electricity rates. Therefore, it is in Kentucky's interest to ensure that any distributors that choose to leave TVA can do so at the lowest cost to the distributor and to remaining TVA customers in Kentucky. Interestingly, FERC recently ordered TVA to provide interconnection service to a Kentucky utility attempting to serve a TVA distributor that had previously given notice. For the moment, the cost details are left to the parties. Because of the implications for Kentucky, for both customers of utilities seeking to leave TVA and those choosing to stay, policy makers should closely monitor these developments.

Other Federal Regulatory Issues

Environmental regulation by the EPA can impact the cost of electricity, especially in a state such as Kentucky whose generation fleet is primarily coal fired generation. Recently, the Clean Air Impact Rule, a multi pollutant strategy was issued by the EPA to address sulfur dioxide and nitrous oxide, which contribute to fine particle pollution and ground level ozone. The EPA estimates that by 2015 these rules will have a cost associated with them of $3.6 billion (1999$) and estimates health benefits of $85-100 billion and visibility benefits of $2 billion.[2] The cost to Kentucky's retail electric consumer was estimated to be 3.4 mills/kWh by 2015.[3]

The Clean Air Mercury Rule ("Mercury Rule") was also released in March of 2005. This rule makes the United States the first country to regulate mercury emissions from coal-fired power plants. According to EPA estimates,[4] when fully implemented, these rules will result in a 70 percent reduction in utility mercury emissions. This is expected to be done in a cap and trade, market-based manner.

According to Kentucky Environmental and Public Protection Cabinet ("EPPC") testimony in Commssion Case No. 2005-00090, economic growth, greater efficiency and a move to meet/address higher electricity demands are expected to continue over the next two decades. Real economic growth is forecast to increase by an average of 3.1 percent per year through 2025. Reflecting greater efficiency, the use of energy will grow by a slower 1.4 percent per year on average or by a total of 35.5 percent. Consumption of all sources of energy will increase: petroleum by 39 percent, coal by 34 percent and renewable energy by 37 percent.[5]

Even though there have been improvements in environmental quality while increasing use of coal, this increased demand for coal-fired electricity will

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[2] *http://www.epa.gov/cair.*
[3] *http://www.epa.gov/cair/state/ky.html.*
[4] *http://www.epa.gov/air/mercuryrule/.*
[5] PSC Case No. 2005-090, EPPC Comments, page 4.

demand newer, more advanced clean coal technology. Investments in such technology will allow Kentucky coal to be utilized as an important energy resource, while protecting the environment.

According to testimony from the EPPC, "power plants utilizing Integrated Gasification Combined Cycle ("IGCC") generation can significantly reduce air emissions, water consumption and solid waste production, and offer the potential of a technical pathway for cost effective separation and capture of carbon dioxide emissions and for co-production of hydrogen." Should there be greenhouse gas rules, such as limits on carbon dioxide emissions, this will become increasingly important, and investment now will reduce investment needed in the future, should existing plants have to be retrofitted in order to meet carbon sequestration rules.

According to EPPC testimony, there are other regulatory programs such as the Clean Water Act and the federal Resource Conservation and Recovery Act that impact electricity generation in Kentucky. It is expected that these will become more stringent and more costly and will place upward pressure on the price of electricity in the nation and in Kentucky as well.

Increased environmental regulation for coal-fired plants relative to other technologies could impact Kentucky's low cost electricity advantage. Kentucky should actively seek available federal funds for research and development including demonstration projects for cleaner energy production technologies. Kentucky should seek to become a national leader in energy production technology.

The way in which FERC and the RTOs plan and price the infrastructure additions, such as transmission lines, is of concern. There is potential for retail ratepayers to subsidize the building of this infrastructure and to receive limited benefit from its development. In addition to concerns regarding the financing of transmission lines, siting of transmission lines is difficult, often taking years to complete a line's permitting and construction. In addition to necessary environmental and regulatory hurdles there is a strong "not in my backyard" feeling among citizens and landowners.

NATURAL GAS ISSUES

Progress toward natural gas deregulation began in 1979 with the Natural Gas Policy Act. As a result of further action by the FERC and the Well-Head Decontrol Act of 1989, natural gas was fully deregulated as of January 1, 1993, allowing market forces of supply and demand to determine the wholesale price of natural gas. As the wholesale market matured, natural gas prices became more volatile and in general have increased over the last few years. In fact, current natural gas prices are more than double the price of five years ago, as wells operating at a lower marginal cost are depleted, and higher marginal cost wells supply more of the natural gas in the market. It is in this environment that local distribution companies ("LDCs") and state regulators must now operate.

Public Service Commission Jurisdiction

The Commission oversees five investor-owned LDCs, as well as more than 25 smaller LDCs. Those companies together have about 654,000 residential customers and nearly 70,000 commercial and industrial customers. The Commission regulates these companies with regard to safety and price.

The Commission oversees the rates charged by Kentucky LDCs. The Commission sets the rates for delivery of natural gas to customers but, because of deregulation, has no control over the wholesale price of gas. The Commission must allow LDCs to pass through the wholesale cost of gas, within reason, to customers. Although the Commission is limited in its ability to affect the final bill to the customer, it has taken some measures recently to ensure that the gas costs are fair, just and reasonable.

Because the gas cost is a large portion of the total customer bill, the Commission conducted a management audit in 2002 to investigate the natural gas purchasing practices of the five major LDCs in Kentucky. The audit was conducted by The Liberty Consulting Group and resulted in a report filed with the Commission in November 2002. While Liberty suggested some changes in order to fine tune the practices of the LDCs, the report was overall very complimentary of the LDCs and their practices.

Another avenue that the Commission has explored in order to help mitigate the effect of price volatility on customers is to approve hedging plans proposed by four of the five major LDCs. These plans lock in or cap the price paid for a certain volume of the gas purchases, which is then averaged in with the price of stored gas and market purchases. Stored gas itself acts as a form of hedging, with LDCs buying gas when the price is lower and withdrawing from storage in the winter when the price is higher. While these hedging activities will not guarantee the lowest price to the customer, they have proven helpful in decreasing volatility in a customer's gas cost.

The Commission also approved a customer choice program for one of its major LDCs, Columbia Gas of Kentucky ("Columbia Gas") in 2000. This program allows customers to choose their own natural gas supplier from a list of approved marketers or to stay with Columbia Gas as the supplier. This choice allows the customer to choose from a menu of options offered by the marketers such as a fixed price, a discount from Columbia Gas's rate, or a market price. Customers are usually required to sign up for a specified period of time, but can change to another marketer with proper notice or on the anniversary date of the contract. Results filed by Columbia Gas show that, in most cases, customers who participated in the program were able to realize savings on their gas costs.

Pipeline Safety

The United States Department of Transportation ("DOT") has jurisdiction over pipeline safety. The DOT has delegated the authority to regulate intrastate pipeline safety to the Commission, including municipal gas companies and other pipeline owners not otherwise regulated by the Commission.

Pipeline safety is a concern as infrastructure ages. Governor Fletcher has appointed an advisory committee and charged them with examining where regulatory changes may be needed, at the state and federal levels, to improve pipeline safety. This advisory committee may file comments to the Secretary of DOT. Pursuant to the Federal Pipeline Safety Improvement Act of 2002, the

Secretary of DOT must respond to these comments, setting forth what action, if any, the Secretary will take on recommendations.

Kentucky Natural Gas Production

Kentucky ranks 18th among the states in natural gas production. There are undeveloped gas reserves, particularly in eastern Kentucky, and the volume of available gas is likely to increase as coal bed methane is discovered and technology for extraction is improved. A key obstacle to developing many of those reserves is a lack of pipeline capacity. Just as interstate electricity transmission is under the jurisdiction of FERC, interstate natural gas pipelines are under FERC's jurisdiction. In order to increase exports of Kentucky natural gas as well as to facilitate intrastate sales, it is necessary to inject natural gas into the pipeline. With this lack of pipeline capacity, it is difficult to take advantage of our reserves. FERC must give federal regulatory approval for new pipeline capacity.

The lack of pipeline capacity can affect both well owners and the tax revenues of a state such as Kentucky. If well owners are unable to access interstate pipelines, they are unable to sell their gas and must forego revenue; therefore, the state loses tax revenue. This lack of pipeline capacity can lead to well owners being "shut-out" if they have interruptible transportation service with the pipeline, which allows the pipeline to curtail accepting the gas when firm transportation customers need the capacity. As coal bed methane production and LNG terminals increase their use of the pipeline, this decrease in pipeline capacity will become more of an issue. Constructing additional pipelines in

Kentucky would help alleviate the problem; however, this type of construction is expensive and must obtain regulatory approval from the FERC.

Natural Gas for Electricity Production

Also of concern to the Commission with respect to natural gas is the abundance of natural gas fired electricity. In Kentucky, these units have traditionally served as "peaking units," providing electricity when needed and not being used when base load coal-fired generation is less expensive. In many other states gas is used for intermediate combined cycle units and base load units. Impacts on Kentucky from this are twofold, natural gas that is used for electricity generation replaces coal as a fuel source, which impacts Kentucky as a coal producing state. At the same time, this increased demand for natural gas for electricity generation results in a higher cost for consumers who rely on natural gas for heat because of the forces of supply and demand in the natural gas market.

Barton-Domenici Energy Policy Act Natural Gas Provisions

Title III of the new Energy Policy Act is devoted to oil and natural gas, and contains provisions that are designed to provide for greater FERC oversight of natural gas markets, and increase natural gas production and pipeline capacity. As noted previously, the commodity price of natural gas is established in markets under federal jurisdiction and is largely driven by supply (production and storage) and demand forces, along with deliverability constraints. However, there have also been documented instances of gas market price manipulation in recent years. Presumably, the new changes in law intended to increase gas production, expand pipeline capacity, and to better police interstate markets will have a positive effect on future wholesale natural gas prices. Since LDCs must pass through to customers the wholesale price of natural gas, any steps to lower this price benefits Kentucky natural gas consumers.

Noteworthy changes made by this Title are as follows:

- Extends FERC jurisdiction over the import and export of natural gas in foreign commerce and liquefied natural gas terminals (Sec. 320)
- Prevents regulation under the Safe Drinking Water Act of underground injection used for hydraulic fracturing in oil and natural gas production (Sec. 327)
- Designates FERC's record as the official record for federal administrative appeals relating to interstate pipeline construction; strengthens the penalties and enforcement of gas market manipulation and requires additional reporting of market information (Sec. 332, 333)
- Requires federal agencies to cooperate regarding oil and gas leasing on public lands (Sec. 344)
- Allows states to regulate coalbed methane production (Sec. 358)

THE WORLD TRADE ORGANIZATION AND ENERGY MARKETS

In addition to the federal and regional forces impacting Kentucky's utility industries, current negotiations regarding international trade agreements may impact Kentucky's utilities. In February 2000, the member states of the WTO began negotiating the GATS. In addition to services such as banking, construction, insurance, tourism and transport, the negotiations have included services typically provided as public services, such as education, health care and utilities. The provisions that included energy services could threaten regulated utilities.

The process is very fluid and the final impacts are uncertain at this time. If implemented as was proposed in earlier drafts, the Agreement would impact both state and federal regulation of electricity. The rules as proposed would apply to more than cross border trade; they would also affect state and federal regulations of utilities or domestic electricity markets. It is unclear as to how Kentucky entities could be impacted. If implemented, these rules would impact state and federal utility regulation in the following ways: (1) The GATS Agreement would prohibit monopolies for services "incidental to distribution of electricity," which would impact our utilities because of dedicated service territories; (2) The Agreement would require that third parties such as independent wholesalers or generators have access to transmission facilities even if such facilities were reserved to serve native load; and (3) State regulatory commissions would be limited to regulations that are no more burdensome than necessary to ensure the quality of service. If these rules are implemented, that would result in a fundamental change in electricity regulation in states such as Kentucky, eliminating the ability of the Commission to ensure fair, just and reasonable rates for electricity. This would likely result in higher rates to customers.

As mentioned, this process is in the negotiation stages and is very fluid. The United States Trade Representative ("USTR") is the negotiator on behalf of the United States in a process set forth in 1994 by the member nations of the WTO. The process is one of "offers" and "counter-offers" by member nations. The latest USTR "offer," dated May 31, 2005, did not include the earlier proposals regarding electricity. At this stage, it is uncertain as to whether this alleviates concerns.

The latest "offer" includes pipeline transportation of fuels and storage facilities. There remains concern that this could impact state and federal natural gas and liquefied natural gas terminals. While the threat on electricity regulation may be alleviated at this point, given the potential implications for Kentucky, these negotiations merit close attention.

CONCLUSION

Kentucky enjoys an enviable position in the nation, having the lowest electricity rates in the country. In order to preserve this distinction which is crucial to attract industry, attention must be paid to RTO and other wholesale market policies at the FERC, as well as any force which would attempt to force de-regulation of Kentucky's regulatory model which has worked so well, whether it be federal policies or international treaties such as GATS.

With regard to environmental regulation, a balance must be maintained between environmental and economic health. Kentucky must be forward looking and be able to meet more stringent environmental standards, while maintaining its relative price advantage with regard to electricity.

If Kentucky is to maintain its low-cost advantage, its utilities must continue to invest wisely in meeting the future generation and transmission needs of customers. At the same time, Kentucky must critically assess the likelihood that environmental or other restrictions will limit the ability of Kentucky's utilities to construct needed electricity infrastructure in the future. Policy makers and utilities should continue to consider cost-effective initiatives that will help to mitigate this risk.

Finally, given the continued focus at the federal level on interstate electricity market development, Kentucky should continue to consider the costs and benefits of participation in these markets. Factors to consider include the potential impacts of increased sales of surplus power by utilities as well as the economic impact of IPPs locating in Kentucky along with additional costs that may be imposed upon ratepayers. Kentucky can help shape electricity policy developments by remaining active and engaged at the regional, national, and international level. If federal policies ultimately require increased participation by Kentucky's utilities in interstate markets, then state policies must evolve to ensure that Kentucky consumers benefit and are protected.

With regard to natural gas, while the wholesale cost of natural gas and the national forces of supply and demand control a large portion of what Kentucky ratepayers face, LDCs must continue to ensure safe and reliable service. Aging infrastructure must be addressed in order to ensure the safety of Kentuckians. Where able, the LDCs must continue to take action to mitigate the wholesale market impact by wisely using storage and hedging mechanisms. The Commission must continue to monitor purchasing practices. Pipeline capacity must be increased if Kentucky is to take advantage of its natural gas reserves, including coal bed methane. This lack of pipeline capacity is impacting owners of reserves because it results in lost revenue and impacts the state and local governments because of the resulting reduced tax revenue.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

CONSIDERATION OF THE REQUIREMENTS OF THE FEDERAL ENERGY POLICY ACT OF 2005 REGARDING TIME-BASED METERING, DEMAND RESPONSE, AND INTERCONNECTION SERVICE	))))))	ADMINISTRATIVE CASE NO. 2006-00045

ORDER

On August 8, 2005, President George W. Bush signed into law the Energy Policy Act of 2005 ("EPAct 2005"). EPAct 2005 amends the Public Utility Regulatory Policies Act of 1978 ("PURPA") by adopting new standards for electric utilities regarding net metering, fuel source diversity, fossil fuel generation efficiency, smart metering, cogeneration and small power production, and interconnection. EPAct 2005 requires that certain actions be taken by each electric utility and each state regulatory authority regarding the EPAct 2005 amendments.

The Commission initiated this administrative proceeding on February 24, 2006, to consider the requirements of EPAct 2005, Subtitle E Section 1252, Smart Metering, which concerns time-based metering and demand response, and Section 1254, Interconnection.

EPAct 2005 requires each state regulatory authority to conduct a formal investigation and issue a decision on whether or not it is appropriate to implement certain Section 1252, Smart Metering standards no later than 18 months after the enactment of EPAct 2005. State regulatory authorities are also required to commence consideration of the Section 1254, Interconnection standard or set a hearing date for its consideration no later than one year after the enactment of EPAct 2005. Each state regulatory authority is to complete its consideration and make a determination whether to implement the interconnection standard within two years after the enactment of EPAct 2005.

A hearing was held on July 18, 2006 to consider the time-based metering and interconnection standards set forth in EPAct 2005. With the issuance of its Order in this proceeding, the Commission satisfies the EPAct 2005 requirements relating to Section 1252, Smart Metering, and Section 1254, Interconnection.

All of Kentucky's jurisdictional electric utilities have been made parties to this case even though, according to Title I of PURPA, not all are subject to these sections of EPAct 2005. Intervention was granted to the Attorney General's Office of Rate Intervention ("AG"), Hunt Technologies and Cellnet Technology ("Hunt" and "Cellnet"), Kentucky Industrial Utility Customers, Inc. ("KIUC"), Metro Human Needs Alliance ("MHNA"), and PJM Interconnection ("PJM") (collectively "Intervenors").

The Order initiating this case included a procedural schedule which provided for discovery, the filing of testimony by the jurisdictional utilities and Intervenors, a public hearing, and the filing of post-hearing briefs. In addition to receiving testimony, the Commission received comments from individuals who are not parties to this case. One individual, Geoffrey Young, presented comments at the hearing. He addressed numerous issues including the standards for interconnecting customer-owned generation to the utility's grid. Ten other individuals filed comments, all in opposition to the mandatory adoption of smart metering standards.

SECTION 1252, SMART METERING

EPAct 2005 Section 1252, Smart Metering, requires each state regulatory authority to conduct a formal investigation and issue a decision on whether or not it is appropriate to implement certain Section 1252 standards. Two Section 1252 standards directly impact Kentucky.

The first standard, if adopted, would require each jurisdictional electric utility to offer each customer class, and provide upon request, a time-based rate schedule where the rate charged varies during different time periods and reflects the variance in the utility's cost of service. A time-based rate schedule will allow a customer to manage energy use and cost through advanced metering and communications technology.

The types of time-based rate schedules that may be offered and thus considered include:

- Time-of-use pricing – prices are pre-established for a specific time period on an advanced or forward basis based on the utility's cost of service. This allows consumers to vary demand and usage in response to these prices to manage their energy cost by shifting usage to a lower cost period or reducing overall consumption.

- Critical peak pricing – time-of-use prices are in effect except for certain peak days when prices may reflect costs at a higher cost of service. Consumers may receive additional discounts for reducing peak period energy consumption.

- Real-time pricing – prices are set for a specific time period on an advanced or forward basis reflecting the utility's cost of service. Real-time prices may change as often as hourly.

- Credits for consumers with large loads that enter into pre-established peak load reduction agreements that reduce a utility's planned load capacity obligations.

The second standard, if adopted, would require each utility to provide each customer requesting a time-based rate with a meter capable of enabling the utility to offer and the customer to accept and receive such a rate.

None of the parties submitting testimony or briefs support the mandated adoption of the Section 1252 smart metering standards. The electric utilities all support the idea of smart metering, time-based pricing, and demand response but oppose the imposition of statewide standards. The Intervenors testified that they also support the idea behind the programs but have concerns about the imposition of non-voluntary statewide standards that may increase the costs of non-participants.

As shown by the testimony of Kentucky's jurisdictional electric utilities, Kentucky's low electricity rates, the minimal difference between current rates and real-time prices, and the uncertainty of the costs and benefits of smart metering all make it inappropriate for the Commission to mandate a statewide smart metering standard. Those same factors also make it questionable whether Kentucky's electricity consumers could enjoy reduced costs from mandated smart metering or real–time pricing.

With the exception of certain direct load control and off-peak electric thermal storage ("ETS") tariffs, few of Kentucky's jurisdictional electric utilities offer time-based rate schedules to their residential customers.

Two of the cooperatives served by Big Rivers Electric Corporation ("Big Rivers"), Jackson Purchase Energy Corporation ("Jackson Purchase") and Kenergy Corp. ("Kenergy"), offered a time-based tariff that became effective in 1991, but it was subsequently withdrawn due to lack of interest.[1] Currently, Big Rivers' third member cooperative, Meade County Rural Electric Cooperative Corp. ("Meade County RECC"), has an optional time-of-day rate (on peak/off-peak pricing) available to residential,

[1] Big Rivers' Response to the Commission's Order dated February 24, 2006, Smart Metering, Item 1.

commercial and industrial customers.[2] None of Big Rivers' members offer direct load control tariffs.

Duke Energy Kentucky, Inc. ("Duke Kentucky") offers its residential customers a direct load control tariff for air conditioners but does not offer any time-based tariff to its residential customers. Duke Kentucky does have time-of-use, real time pricing and load management tariffs available for its commercial and industrial customers.

Members of East Kentucky Power Cooperative, Inc. ("EKPC") offer a variety of time-of-day pricing and load management, and interruptible tariffs to their commercial and industrial customers. Most, but not all, of EKPC's members offer an off-peak, time-of-use tariff available to residential customers with ETS capability. Of the 4,870 customers on time-of-day or interruptible rates, 4,769 or roughly 99.8 percent are on the ETS tariffs.[3] Five of EKPC's members offer residential time-of-use pricing but have no customers currently on those tariffs. EKPC and its members do offer an array of demand-side management ("DSM") programs to their residential customers.[4]

Kentucky Power Company ("Kentucky Power") offers a variety of time-based metering and demand response tariff provisions. Kentucky Power offers residential customers load management and time-of-day options. A separate residential water heating load management tariff is in effect but is available to currently-served customers

[2] Meade County RECC's Response to the Commission's Order dated February 24, 2006, Smart Metering, Item 1.

[3] Testimony of William A. Bosta, Index of Rate Schedules.

[4] EKPC's Response to the Commission's Order dated February 24, 2006, Smart Metering, Item 1.

only. Load management, time-of-day pricing, interruptible, and curtailable tariffs are available to commercial and industrial customers.[5]

Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") offer time-of-day pricing, load reduction incentive and curtailable service tariffs to their commercial and industrial customers.[6] There are no time-based tariffs offered to residential customers, but LG&E is developing a residential real-time pricing pilot program pursuant to the settlement agreement in Case No. 2004-00433.[7] With regard to demand response, KU and LG&E offer demand reduction and energy conservation programs to residential and small commercial customers. Their "Demand Conservation" programs, offered since 2001, provide load management cycling of participants' air conditioning, electric water heating and pool pumps. According to KU and LG&E, over 93,000 load management devices are in operation governing over 85 MW during the summer peak.[8]

All of the electric utilities testified that they have found little or no interest in time-of-use rates by residential customers. Duke Kentucky stated that a residential time-of-use rate had been offered by its parent company in Ohio for years but had never attracted a large number of participants, provided significant system benefits, or

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[5] Kentucky Power's Response to the Commission'a Order dated February 24, 2006, Smart Metering, Item 1, at 2.

[6] Testimony of Kent W. Blake, Exhibit KWB-1.

[7] Case No. 2003-00433, An Adjustment of the Gas and Electric Rates, Terms, and Conditions of Louisville Gas and Electric Company, final Order June 30, 2004.

[8] Testimony of Gregory Fergason at 3.

changed customer behavior.[9] Kentucky Power believes that most of its customers have decided that the economic rewards of time-based programs do not outweigh the inconvenience or cost.[10]

Duke Kentucky states that it is indifferent to the adoption of the EPAct 2005 time-based pricing standards so long as (1) they are not mandatory for all customers[11] and (2) any time-based program based on the standards is cost-effective.[12] EKPC argues that, due to rate levels and metering costs, its members' residential customers may not shift load under time-based pricing and believes that the Commission should authorize a limited pilot program before enacting any statewide program.[13] Kentucky Power argues that the Commission should not mandate the installation of smart meters for all its customers because no single smart meter solution will work in all circumstances. Kentucky Power's experience has been that providing credits to customers with large loads who enter into peak load reduction agreements is the most cost-effective approach for the company to control peak load.[14] KU and LG&E argue that they are opposed to any statewide mandatory standards concerning smart metering, time-based rates or demand response because there is insufficient data

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[9] Duke Kentucky's Response to Commission's Order dated February 24, 2006, Smart Metering, Item 4.

[10] Testimony of David M. Roush at 5.

[11] Testimony of Bruce L Sailers at 7.

[12] Id. at 10.

[13] Testimony of William A. Bosta at 6.

[14] Testimony of David M. Roush at 6.

concerning the demand response effect of time-based programs beyond those currently offered and there is insufficient data concerning the cost-effectiveness of such programs.[15]

MHNA is an alliance of community nonprofit and governmental agencies serving low income households and individuals in the Louisville Metro area. Nineteen of MHNA's 35 members provide assistance to low income persons.[16] MHNA does not oppose time-based pricing on principle; however, it would oppose any program that would result in higher costs to low-income customers. MHNA expressed its concerns that, if required to participate, low-income consumers may actually face higher costs. These customers would have to pay for the cost of the smart meters and may not have the ability to shift usage to lower cost time periods. MHNA would oppose the imposition of the time-based pricing standards if the utilities would impose costs on non-participants for system-wide infrastructure improvements, even if the programs were offered on a voluntary basis. Therefore, MHNA does not recommend that the Commission mandate any time-based pricing program. MHNA would support a pilot program so long as it did not require mandatory participation and non-participants would not bear any of the costs of the program. MHNA is especially concerned that low-income customers, the elderly, the disabled and the unemployed do not have the ability to take advantage of time-based programs but may face higher electricity costs depending upon the program.[17]

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[15] Testimony of Kent W. Blake at 2 and 3.

[16] Testimony of Marlon Cummings at 1.

[17] Id. at 3-5.

PJM is the regional transmission organization ("RTO") authorized by the Federal Energy Regulatory Commission to operate the transmission grid in the District of Columbia and in all or parts of 13 states, including Kentucky. It is responsible for facilitating the reliable supply of energy to wholesale electricity customers in the PJM region.[18] Noting that demand-side response benefits the wholesale electricity market and that demand-side response participation in wholesale electricity market is underdeveloped, PJM briefly described its demand response programs and their benefits.[19] PJM expressed no opinion as to whether the Commission should adopt the EPAct 2005 smart metering standards, but it did encourage the Commission to explore policies and standards that could bring the benefits of demand-side resources to Kentucky.[20]

Hunt produces meters, including smart meters, for use in the electric, water and natural gas utilities markets. Hunt also delivers advanced metering infrastructure ("AMI") solutions to its customers several of which are in Kentucky. Cellnet is a provider of products that enable utilities' information systems to communicate with residential, commercial and industrial meters using wireless technology. Hunt and Cellnet have been involved in more than 10 EPAct 2005 smart metering proceedings.[21] Hunt and Cellnet testified that they generally support the testimony filed by the jurisdictional electric utilities and provided some additional comments.

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[18] Testimony of Thomas Welch at 3.

[19] Id. at 4-6.

[20] Id. at 9.

[21] Testimony of Scott H. DeBroff at 2.

Hunt and Cellnet agree with Duke Kentucky that smart metering will require a cost-benefit analysis before a utility would invest in advanced metering infrastructure. They also agree with KU and LG&E that how certain kinds of smart metering, time-based rates and demand response programs will function will vary, depending on where they are implemented in Kentucky. Hunt and Cellnet support EKPC's continued offering of time-of-day programs to large commercial and industrial customers. They also support EKPC's recommendation to implement pilot programs to test the system capabilities of all utilities that had made AMI investments, provided the costs of the programs are borne by the entities that benefit. Finally, Hunt and Cellnet support Big Rivers' concerns about the utilities' abilities to recover the costs of advanced metering and the assurance of no cross-subsidization.[22]

Having reviewed the testimony in this proceeding and publicly available information regarding time-based pricing, the Commission has determined that the Smart Metering standards as set forth in Section 1252 of EPAct 2005 should not be adopted by Kentucky's jurisdictional electric utilities. The Commission finds that the combination of Kentucky's low rates for electricity, the significant costs and the uncertainty of benefits do not support the need for mandated smart metering standards at this time.

It does appear, however, that certain aspects of demand response programs and time-based pricing are not only practical but economically feasible at this time and should be further explored. While we are not mandating any particular standard, the

[22] Id. at 3-5.

Commission does direct each jurisdictional electric utility to give further consideration to demand response and time-based products as discussed in this Order.

The jurisdictional electric utilities either specifically cited or generally referenced the varied array of DSM programs they offer their customers. While recognizing the different characteristics of each utility's service territory, the Commission strongly encourages the jurisdictional electric utilities to consider broadening the array of DSM programs available. The load management programs offered by KU and LG&E, where air conditioning systems, electric water heaters and pool pumps are cycled, appear to have been particularly effective in that KU and LG&E have identified a temporary demand reduction potential of over 85 MW. The Commission encourages the electric utilities with load management programs to consider greater promotion of their benefits and minimal costs and strongly encourages those utilities without these types of programs to study the practicality of introducing a residential load management program.

The testimony in this proceeding also showed that, taken as a whole, the jurisdictional electric utilities offer a broad array of time-based pricing products, some mandatory, predominantly to the large commercial and industrial classes that have a greater capability to modify their consumption.

For residential customers, on-peak/off-peak time-of-use or critical peak pricing may hold more potential than real-time pricing products, which would require the use of smart meters, special communication software and perhaps modification of the utility's billing system. As KU and LG&E state, the on-peak/off-peak time-of-use or critical peak pricing forms of time-based pricing also "have costs and benefits more suited to demand response."[23] Currently, only Kentucky Power and a few distribution cooperatives offer on-peak/off-peak time-of-use or critical peak pricing forms of time-based programs to their residential customers. As with load management programs, the Commission encourages the electric utilities offering these tariffs to their residential customers to consider greater promotion of their benefits and minimal costs and strongly encourages those utilities without these types of tariffs to study the practicality of introducing residential time-of-use tariffs.

With respect to the pilot real-time pricing program LG&E was developing pursuant to the settlement agreement in Case No. 2004-00433, LG&E stated that it believed that it would be in its customers' best interest to delay implementation until the Commission issued an Order in this case and, therefore, is awaiting further direction from the Commission.[24] The Commission believes that the issues regarding the requirements of EPAct 2005 which concerned LG&E have been resolved. Therefore, LG&E is directed to finalize the proposed pilot program in accordance with the settlement agreement and submit the plan for the Commission's consideration within 90 days of the date of this Order.

As opposed to Kentucky's residential customers, Kentucky's large commercial and industrial customers operate on some form of on-peak/off-peak time-of-use tariffs as well as curtailable or interruptible service tariffs. Many have done so since shortly

[23] KU and LG&E's Response to the Commission's Order dated February 24, 2006, Smart Metering, Item 3 at 2.

[24] KU and LG&E's Response to the Second Data Request of Commission Staff dated April 13, 2006, Item 22 at 5 and 6.

after the Commission adopted the PURPA Section 111 standards in 1982.[25] In that proceeding, the Commission adopted standards that generally prohibited declining block rates and mandated the implementation of time-of-day rates, seasonal rates, interruptible rates and load management techniques for each customer class.[26]

At this time, however, only Duke Kentucky offers a real-time pricing tariff. The Commission believes that some of the large commercial and industrial customers of the other jurisdictional utilities may benefit from real-time pricing tariffs because such customers have greater operating flexibility and, therefore, greater ability to modify their consumption patterns. In addition, the cost of implementing real-time pricing may be cost effective for these larger customers. The Commission further finds that the potential for significant savings from commercial and industrial real-time pricing programs has not been adequately investigated in the Commonwealth. To gain information and attempt to ascertain the viability and effectiveness of real-time pricing for larger customers, the Commission will require that pilot programs be developed and offered to such customers. The Commission, therefore, directs Kentucky Power, KU and LG&E to develop voluntary pilot real-time pricing programs for their large commercial and industrial customers. Big Rivers and EKPC are directed to work with each other, in conjunction with their member distribution cooperatives, to develop one or more voluntary real-time pricing pilot programs to be offered by a representative but selective group of members to their large commercial and industrial customers.

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[25] Administrative Case No, 203, The Determinations with Respect to the Ratemaking Standards of the Public Utility Regulatory Policies Act of 1978 Identified in Section 111(d)(1)-(6), Order dated February 28, 1982.

[26] Id. at 17-43.65

Kentucky's jurisdictional electric utilities, with the exception of Duke Kentucky, are to submit the proposed real-time pricing tariffs for their large commercial and industrial customers for Commission consideration within 120 days of the date of this Order. The pilot programs should be designed to operate for an initial term of three years. Annual reports will be required with the content to be determined after the proposed pilots have been filed. The filings should clearly define and address all aspects of such a program from selection of pricing periods to proposed costs.

Given the decision not to adopt the Section 1252, Smart Metering standards, the Commission further finds that it will not require the electric utilities to provide a time-based meter appropriate for such a rate as set forth in the second Smart Metering standard. The Commission will, however, require the utilities proposing real-time pilot programs to provide appropriate metering to participants in those programs.

SECTION 1254, INTERCONNECTION

If adopted, Section 1254, the Interconnection standard, would require each electric utility to make interconnection service available to any customer. EPAct 2005 defines interconnection service as service to an electric consumer under which a generating facility on the consumer's premises is connected to the local distribution facilities. The service is to be offered based on standards developed by the Institute of Electrical Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems ("IEEE 1547"). The IEEE 1547 standards provide for just and reasonable agreements and procedures to be established so the services offered promote current best practices of interconnection for distributed generation.

According to their testimony, reliance solely on IEEE 1547 is a concern of the electric utilities. All of the jurisdictional electric utilities have some sort of interconnection process, procedure or guidelines. Certain interconnection requirements are referenced in their small power and cogeneration tariffs as well as their net metering tariffs. The majority of the net metering tariffs filed by the electric utilities specifically reference compliance with IEEE 1547. Some of the electric utilities believe that adoption of a statewide standard may be beneficial in that it would promote uniform interconnection practices. However, none of the electric utilities believe that IEEE 1547 alone is sufficient, and they recommend that any standard adopted not limit their flexibility to include additional interconnection requirements for safety and reliability. The electric utilities also recommend that any standard adopted should not prevent them from full recovery of interconnection costs from the connecting generation source.

None of the intervening parties submitting briefs addressed interconnection, although PJM did address interconnection in its pre-filed testimony. While PJM expressed no opinion as to whether the Commission should adopt the EPAct 2005 interconnection standard, it did encourage the Commission to explore policies and standards that could bring the benefit of demand side resources to Kentucky.[27]

Based on a review of the evidence, the Commission must concur with the jurisdictional electric utilities and find that, while IEEE 1547 addresses interconnection of distributed resources of 10 MVA or less, IEEE 1547 alone will not be sufficient to ensure the safety and reliability of the transmission and distributions systems.[28] As

[27] Testimony of Thomas Welch at 9.

[28] Testimony of Travis D. Housley at 5.

EKPC states, while IEEE 1547 sets the minimum requirements for connecting a 10 MVA generating system, a substantial redesign of the distribution system may still be required to ensure safe and reliable operation.[29] In addition, we agree with Kentucky Power that the unique design, construction and operation of each electric utility's power system are "practical considerations" that argue against imposing a statewide standard.[30]

Therefore, the Commission finds that a single statewide interconnection standard should not be adopted. We believe that the electric utilities have adequately demonstrated that compliance with IEEE 1547 alone is not sufficient to ensure the safety and reliability of an electric utility's transmission and distribution system. Nevertheless, we believe that the record demonstrates the merit of the requirements of IEEE 1547 and conclude that each jurisdictional electric utility should include IEEE 1547 as the core of its technical interconnection requirements for generation resources of 10 MVA and below.

PURPA AND NON-PURPA ELECTRIC UTILITIES

As stated earlier in this Order, not all of Kentucky's jurisdictional electric utilities are subject to PURPA or EPAct 2005. Only those electric utilities with total annual retail sales greater than 500 million kilowatt hours ("kWh"), or 500,000 megawatt hours, are subject. Big Rivers and EKPC are not subject to PURPA or the standards as set forth in EPAct 2005 because all of their sales are at wholesale. Meade County RECC, a member of Big Rivers, and Big Sandy RECC, Clark Energy Cooperative, Cumberland

[29] Testimony of Paul A. Dolloff at 9 and 10.

[30] Testimony of Stephen E. Early at 1 and 2.

Valley Electric, Farmers RECC, Grayson RECC, Inter-County Energy Cooperative, Licking Valley RECC, and Shelby Energy Cooperative, all members of EKPC, are also not subject to PURPA or the standards as set forth in EPAct 2005 because their retail sales do not exceed the minimum requirement.

In their brief, noting that they are not PURPA-covered utilities, Big Rivers and Meade County RECC asked the Commission to find them exempt from any Commission order requiring compliance with the EPAct standards. In addition, Jackson Purchase notes that a list of covered utilities published in August 2006 by the federal Department of Energy ("DOE") erroneously lists Jackson Purchase as a PURPA-covered utility that is not subject to Commission jurisdiction and asks the Commission to notify DOE of its error by October 1, 2006.

In its brief, EKPC also notes that it and several of its members are not PURPA-covered utilities. EKPC notes that it is participating in this case for the purpose of coordinating the representation of its member systems and describes various actions it has taken under PURPA on behalf of its members. EKPC does not request to be exempted from any Commission directive. EKPC states that it will continue to provide services to its members that are beneficial and economical in relation to any EPAct standards that are adopted by the Commission.

The Commission reviewed DOE's August 2006 list of covered utilities and submitted pertinent corrections to DOE on September 11, 2006. The exemption from PURPA and certain aspects of EPAct 2005 that Big Rivers notes in its brief, however, does not impact the Commission's jurisdiction over such utilities. Pursuant to its authority under Chapter 278 of the Kentucky Revised Statues, the Commission has determined, based on the record in this case, that the requirements set forth in this Order should apply to each jurisdictional electric utility, irrespective of that utility's status under PURPA.

SUMMARY

Although the Commission has determined that Kentucky's jurisdictional electric utilities need not adopt either the Section 1252, Smart Metering standard or the Section 1254, Interconnection standard, the Commission finds value in the theory behind these standards, as have the electric utilities and Intervenors. The Commission is sensitive to the concerns expressed by the electric utilities and Intervenors in this proceeding. The Commission believes that its decision balances the positive aspects of the standards with the concerns of the parties in this proceeding.

IT IS THEREFORE ORDERED that:

1. The EPAct 2005 Section 1252, Smart Metering and Section 1254, Interconnection standards shall not be adopted.

2. LG&E shall finalize its proposed residential real-time pilot pricing program in accordance with the settlement in Case No. 2003-00433 and submit the plan for Commission consideration within 90 days of the date of this Order.

3. Big Rivers, EKPC, Kentucky Power, KU, and LG&E shall develop voluntary pilot real-time pricing programs for their large commercial and industrial customers in accordance with the discussion in this Order.

4. Each jurisdictional electric utility shall include IEEE 1547 as the core of its technical interconnection requirements for generation resources of 10 MVA and below by inclusion in its policies and procedures, or tariffs whichever is appropriate.

Done at Frankfort, Kentucky, this 21st day of December, 2006.

By the Commission

ATTEST:

Executive Director

pp. 32-42

Overland
Consulting

Analysis of Section 50 of the Incentive for Energy Independence Act

Commission Staff Interview Notes Based on Interviews Held in Frankfort, Kentucky December 19- 20

Interviews Conducted by:

Howard Lubow, Overland Consulting
Steve Ostrover, London Economics

December 26, 2007

Commission Staff Interview Questions & Related Notes
December 19-20, 2007

Participants: Beth O'Donnell, Executive Director; Bob Amato, Deputy Executive Director; Jim Welch, Director Engineering; Aaron Greenwell, Asst. Director, Division of Financial Analysis; Richard Raff, attorney; Jeff Shaw; John Rogness, Branch Manager, Management Audits; Quang Nguyen, attorney.

IRP evolution -- To avoid another Big Rivers, Wilson plant fiasco in the future. Held meetings with stakeholders; AG. KIUC wanted a formal process; wanted a statewide process. Asst. Executive Director worked with group that developed the current statute. Generally satisfied with IRP process in terms of regulatory oversight.

CPCN applications are, in fact, consistent with IRP filings.

Also, now have DSM process, and filings. This arose from IRP.

A more formal IRP process would put a significant additional burden on Commission resources.

> Currently, there is a formal case number and a public notice of filing. ***There is nothing to preclude other parties from being involved.*** Staff files discovery. There is a Procedural Schedule which Includes an informal conference; intervenors can file comments; the utility files a reply. The only real difference is the lack of a commission order. Further, the Staff report does take into account and consider the positions of all party comments.
>
> Parties have rarely, if ever, been denied participation.
>
> Utilities do take the IRP process very seriously. ICF was involved in initial filing reviews. Recommendations have been incorporated. East Kentucky/Big Rivers have less resources; not a fully integrated system; impacts their process.
>
> Originally, there was a statewide overview; not staggered like now. This stopped when consultants were no longer involved. Given KPSC staffing levels it was not possible to develop a statewide plan.
>
> Other parties are interested in more formal process -- Primary basis for more formal basis is compliance.
>
> There have been periodic statewide reviews of generation and transmission systems since 2000. Admin. Case 387 arose from Executive Orders. Also 9500090(?) Both following Governors Office Energy Policy.

After first two rounds of IRP filings, utilities wanted to go to three years.

The primary purposes of IRP process have been accomplished – commission/public understanding of planning.

In 1990s, companies had excess plant capacity relative to native load.

Statewide planning could not induce utilities to plan or dispatch; no interest in ownership on a joint basis. Utilities opposed this due to competition; FERC guidelines.

References to externalities in Staff report – Other parties (party) were pushing this. Arose from Clean Air Act amendments; carbon issues. In general, the Staff reports may or may not reflect KPSC staff position on points raised from the IRP review process. The report also includes noteworthy comments and recommendations of other parties participating in the process.

In 1997 timeframe, the IRP process was actually under consideration to be terminated, due to industry restructuring. Backed off due to energy price spikes during outages at that time, and internal staff interest in continuing the process.

5:058 states that the Commission shall follow KRS Chapter 278, which states that resource plans be adopted to provide "adequate and reliable supply of electricity at the lowest possible cost for all customers with their service areas, and satisfy all related state and federal laws and regulations".

In this context, does the Commission believe that it has the authority to consider externalities in the IRP process?

Can "lowest possible cost" include health and environmental costs not necessarily currently reflected in federal or state regulations?

No recollection of a CPCN case where "externalities" have been raised in a generation facility case.

In 090 case, Commission says they should be in legislation. Commission does not want to go beyond what is in state or federal legislation.

Is the CPN process defined solely by 278.020, and siting by 278.702?

Do current practices and guidelines create any material impediments to consideration of renewables/DSM?

No, they are considered.

Alternatively, is there any explicit requirement to consider renewables or DSM alternatives in these proceedings?

No explicit requirement, but look at IRP. Showing of solicitations for alternative resource projects.

RFP responses have included hydro; other smaller project packages.

To what extent does the Commission currently have any authority over non-utility generating projects within the state?

Siting process only; no CPCN. Zoning, transmission implications, local economic impacts. 7 member board, with 3 commissioners.

What policies are currently in place to assure that utilities will fairly consider IPP or merchant projects?

CPCN process. Utilities have RFP vs. self-build. As a matter of practice, this is always done. If not otherwise performed, Commission would require it.

Does the Commission currently exercise any oversite of utility bid solicitations for new power resources?

Review only.

Does the KPSC have the authority to mandate a certain percentage of capacity requirements be met by renewables; DSM?

Commission does NOT have authority to direct renewables.

Does the KPSC have the authority to require application of specific screening models; and input assumptions in utility review of demand and supply side options?

Can make a DR request, if alternate cases are of interest. Commission position has been NOT to REQUIRE any particular model or assumptions. Commission does not have authority to force a particular test or particular assumptions. However, the Staff does not need to accept the utility tests and results.

Utilities do cooperate in running alternate cases, as requested.

Is the Commission inclined to mandate the implementation of alternative rate structures -- time of use; seasonal rates; inverted rates?

In place generally – on/off peak. There is no specific PSC policy re conservation; load shifting.

Rate design has generally moved away from declining block rates. Now, rates are generally flat.

(2006 – 045) Case reviewed demand response. Encouraged use of rate design pilot programs for commercial/industrial.

TOU for residential is also in pilot programs.

What limits does the KPSC believe restrict its current authority in implementing alternative rate structures? For example, new surcharges – a "public good" surcharge to subsidize coal gasification, DSM or other renewables projects?

Commission position has been that it cannot raise rates to subsidize low-income customers. Home heating assistance is part of the DSM Statute. These are sometimes distributed by a third-party agency.

There are no subsidies in place now to create public goods funds. It is not clear if the Commission has authority for this. If funds were to be used by the utilities for programs, then it would likely be ok. However, if funds were collected by the utilities, and then remitted to a state agency, such a process would not be within the jurisdiction of the Commission.

The current fuel-adjustment clause is specifically covered under 807 KAR 5:056.

Should a more diversified portfolio result in increased direct costs, can such costs be included under the current FAC provision? Are all currently-mandated environmental compliance costs includable in the FAC?

Must be included in the identified FERC Accounts.

278.285.1 Demand-side management plans.

Paragraph 1 – The commission may determine the reasonableness of demand-side management plans ***proposed by any utility*** under its jurisdiction.

This language does not seem to provide for Commission authority to direct DSM programs on its own initiative or direction. Is that correct?

Correct. Utilities make filings. Intervenor may make recommendations – ie. Larger scale of programs, which staff has recommended.

Duke – annual; KP – semi-annually; LGE/KU – file annually.
DSM Surcharge – information is filed with commission. Filings occur at different intervals.

LGE/KU – advisory group. Duke/KP – collaboratives.

278.466 Net Metering

Paragraph 2 -- Excess metering costs. Have any customers been assigned such costs under this provision? Does the Commission know if these costs are being uniformly applied by Kentucky utilities?

There have been no formal complaints; some groups have argued that utilities have created barriers, but commission views safety concerns to be legitimate.

Does the Commission have the authority to consider recognition of higher returns, and/or faster depreciation for increased risks incurred by regulated companies investing in new technologies, renewables, and/or DSM projects?

> No explicit authority for this. KPSC does not believe that it has authority to specify a renewables target.

Within its current regulatory authority, can the Commission provide utility rate recovery for the extension of credit enhancements to developers of new power resources?

> DSM mechanism provides for some of this. This is considered within specific cases. However, stated position is that this should be through tax breaks or customer rates. Any broader authority need to derive from statutes.
>
> Portfolio Analysis -- Administrative Case (0300) – Now open.
>
> There is a requirement to favor the use of coal.
>
> Some proceedings have begus to look at the benefits of diversification, but no use of specific analytical techniques. Utilities have filed comments.
>
> 807 KAR 5:054 Small power production and cogeneration.

Section 5. Requires that utilities file avoided cost data every two years. Is this data currently available?

> Filed apart from IRPs. Used for cogen to establish avoided cost.
>
> EKP – do they use an avoided cost for capacity?? May not use for cogen; other utilities as well.
>
> **KPSC has not required recognition of capacity costs. Has not revisited this in recent years.**
>
> No one has filed a complaint with the Commission.
>
> Have considered potential modification of Cogen regulation.

To what extent is the KPSC involved in utility transmission system planning? Does the KPSC participate in relevant FERC proceedings?

> Commission participates in MISO.
>
> KY statute re transmission. Equivalent to a CPCN case. Must demonstrate alternatives and potential routes. Constraints are primarily major power flows from outside and through the State; not within it. (See 387; and 090 cases)

Kentucky Infrastructure Study, August 2005. (090) Page 42 references a PJM "Project Mountaineer", to develop transmission capacity enabling development of coal generation for export and to improve reliability. What is the status of this project?

W. Virginia – yes, it's now under construction(??) AEP line.

Has DOE designated any "national interest corridors" in Kentucky? (Infrastructure Study, p. 43)

No.

At Infrastructure Study, page 49, statements indicate that consideration of environmental cost impacts "is not necessary or appropriate at this time". Further, "…the inclusion of externalities in the price of electricity implies that those that consume electricity are solely responsible for the existence of the externalities. Such implication may be inaccurate and thus result in an inappropriate transfer of costs".

Was this the formal position of the Commission in August 2005? What is its position today? Where is this position stated – ie. subsequent Orders, releases, etc.

No change in position at this time. (Check the context).

At Infrastructure Study, page 49, it states:

Other states have assured rate recovery or granted higher returns on investments in renewable generation. These actions would raise the cost of electricity to Kentucky's consumers and are less preferable than *other identified incentives* at this time.

Was this the formal position of the Commission in August 2005? What is its position today? Where is this position stated – ie. subsequent Orders, releases, etc

Yes. This is the current position.

What were the "other identified incentives" referred to in this statement?

IGCC – see report. Financial incentives – grants; low interest loans; tax credits. To support renewables and alternative technologies. – ***These are state sponsored invcentives.***

The Commission does not have the authority to create these incentives.

What are the CPCN barriers referred to in consideration of coal gasification projects referenced in the Infrastructure Study, at page 49?

AEP has filed bill with legislature for recovery of IGCC during construction. Never was approved – no need in Kentucky.

LG&E/KU attempted to get this bill, but has not been approved. No IGCC in a CPCN filing to date.

EKP filed for recovery of output from an IGCC plant. Contract was approved, but IPP never got funding. Based on a favorable price. Was based, in part, on burning refuse. This was a least-cost decision, at the time.

At Infrastructure Study, page 50, the Commission explicitly states:

> ***The Commission does not have jurisdiction under KRS Chapter 278 to explicitly allow for consideration of such externalities*** (referring to environmental costs of coal-fired generation)

Has this position changed since August 2005?

Health insurance costs, etc. associated with coal. This is current position.

At Infrastructure Study, page 52, the Commission states its policy as follows:

> **Kentucky's electric utilities should not be punished for burning coal. The Commission believes that Kentucky's environmental policy should be balanced. We encourage the electric utilities, the EPPC and other appropriate agencies and organizations to participate at the federal level to ensure that sound environmental policy is developed.**

Has this position changed since August 2005?

Position is still the same. EPPC should be working at the federal level.

In IRPs, utilities have followed the latest technologies.

"The Impact of Federal and Inter'l Policy on Kentucky's Energy Future", dated August 22, 2005. At page 26, the KPSC report states:

> Increased environmental regulation for coal-fired plants relative to other technologies could impact Kentucky's low cost electricity advantage. Kentucky should actively seek available federal funds for research and development including demonstration projects for cleaner energy production technologies. Kentucky should seek to become a national leader in energy production technology.

Which Kentucky agency is primarily responsible for coordinating funding for research and/or demonstration projects for clean energy generation projects? What is status of efforts?

GOEP. (Talina). Put in a bid for Futuregen; one of 13 sites. Has developed some funding. Sponsors annual Energy Efficiency Conference with Duke; others.

Has the KPSC considered the potential staffing implications associated with the directives required by Section 50? If so, what are the current estimates of staffing requirements? What staffing is currently associated with the IRP/DSM processes currently in place?

5 people; 3-4 FTEs. Likely to increase, even without Section 50 implications.

Overland Consulting

Analysis of Section 50
of the Incentive for Energy Independence Act

Non-Utility Stakeholder Interview Notes
Based on Interviews Held in
Frankfort, Kentucky
December 17- 19

Interviews Conducted by:

Howard Lubow, Overland Consulting
Steve Ostrover, London Economics

December 26, 2007

Energy Act – Section 50 Review
Summary of non-utility stakeholder meetings
December 17-19, 2007

1 Governor's Office of Energy Policy

December 17, 2007
8:30-11:00

Participant: Talina Mathews, Executive Director

- Background includes a previous position as an economist at the KPSC. She was involved with certain sections of HB 1, but not Section 50.
- GOEP objectives are to promote efficient use of Kentucky resources; keep rates low; and protect the environment.
- HB 1 provides a utility coal subsidy -- $2/ton for new coal generation for "clean coal" incremental use. (See pages 39-40) There are substantial coal industry tax subsidies re gasification.

Talina to provide analysis of tax subsidy estimates.

- Coal companies represent that a large percentage of KY coal mine revenue stays in the state.

Talina to provide GOEP comments on coal sequestration.

- GOEP may be a party to the proceedings, but no decision has been made to date. The LaCapra report recently released on behalf of GOEP may be filed in this proceeding. If so, a witness from LaCapra may be produced. However, the report can be submitted into the record by reference.. Talina believed that the recommendations contained in the report were too general.
- Believes that the DSM statute should be changed. The Governor's office, and/or other state agencies should set policy on energy; the PSC should administer energy policies for companies under its jurisdiction.
- Statewide planning arising from the IRP process would be difficult, given the multi-state nature of most Kentucky utilities. This would also place a large burden on the PSC. Historically, there has not been much coordination with TVA, and Kentucky municipals have not been that cooperative. Statewide planning process is not feasible at this time.
- IRP is taken into account in the CPCN process.
- There has been precedent for KPSC Orders in IRP – she was not sure if AEP or Big Rivers. Commission issued an order due to revelations in IRP review, as part of settlement agreement. *(John Rogness to provide documents)*

DSM

- No utilities have taken full advantage of potential programs. Utilities want a higher return; at least equal to cost of capital on generating assets.

- The DSM process provides for utility filings with the PSC for approval. Only the utility can propose DSM programs for PSC consideration.
- Currently inexpensive power limits DSM programs that will pass cost/benefit screening tests.
- No third-party competitors in DSM currently.
- Industrial opt-out provision for DSM surcharge is bad – leads to selective regulation of manufacturers.
- Should have standards to upgrade and enforce building codes. Should also require (not suggest) EE in public buildings.

Renewables – *GOEP has an inventory of potential projects – to be provided.* Mainly hydro.

- Net metering – wind is currently prohibited. PV is approved, but not currently taken advantage of. Safety is a consideration in interconnection. Also relative reliability to meet load is an issue. Output could have higher rate than tariff rate – Green power premium.
- Current net metering provisions are so specific, may require additional legislation to allow expansion to other technologies.

Full-cost accounting.

- More transparency is needed. Vendors (ie. GE) are not releasing data on coal gasification costs.
- Full cost accounting is not good – will inevitably violate one or more of the GOEP policy objectives. FCA can mean different things to different people. Should focus on what is measurable. Indirect costs are ok, if measurable. It would be hard to write FCA into the statute; the KPSC has never considered public health costs before. Believes that unstated goal of Section 50 was to stop coal from being built.
- HB 1 is does not support utility IGCC (See page 5). The bill focuses on SNG; transportation fuels.
- Not aware of any state commission that currently prices "externalities". This would likely drive cost to a level where no new generation would occur – all would be met by DSM and renewables.
- GOEP believes that only direct costs should be considered – no "externalities". The role of the PSC is to review projects that meet standards that protect public health, and are in compliance with current regulations.

Talina questions the appropriateness of consideration of externalities even as qualitative factors. The implied regulatory burden is too high.

Rate Design.

- Opposed to "public good" surcharge if directed by the legislature; it might be used for other purposes. If this is to be considered, Legislature should provide support for a "public interest" surcharge, and describe how it should function.
- Large industrial customers are able to negotiate very low rates; some are at less than the utility cost of capital.

2 Louisville Climate Action Network

Sarah Cunningham
December 19, 2007
3:00-4:30

- Coalition of 14 organizations
- New organization. Mission is to reduce carbon. EE saves money. Network of organizations – focused on education.
- No participation in the DSM collaborative process. LG&E now under advisory group approach. Not contacted to participate in advisory group.
- Eon influence has been more positive – 2007.
- LCAN has no resources to participate in the current proceedings.
- Residential DSM -- $15 energy audit. Quality has declined with increase in interest. Not site specific enough. Load control – HVAC. Pilot program for TOD rates. Lack of utility trust is an issue.
- Project Warm – low-elderly or disabled. Weatherization program. Project Blitz; Project Repair. Energy Conservation workshops – focused on people at risk of disconnects. Underwritten by LG&E. Workshops should get more funding.
- Education is a big issue; needs funding. LG&E turns down some of these requests due to lack of funding.
- Commercial/Institutional – Relamping is obvious program. More efficient HVAC.
- Doesn't see a lot of "passion" to lead DSM programs/education. State Division of Energy should lead in this area.
- Example program – pay for difference in high efficiency motors vs. standard.
- Don't need to build any new generation. Need to be more efficient.
- Organization is focused on education on renewables.
- Use hydro where possible.
- Use waste-products (ie. Wood shavings) where possible.
- Must put pressure on utilities to find alternative ways of meeting energy demand.
- Full Cost Accounting – The full cost of coal should be included in the price of fuel. Willing to account for losses in the coal industry as long as benefits created by new industries are also accounted for.
- LG&E has recently approved a Green rate. This needs more promotion.
- Willing to have surcharge for "Public Good" for EE programs.
- Utilities do not have adequate incentives to more fully implement DSM. However, utilities should be responsible for programs vs. 3rd parties. They know much more about their customers and their service area.

Overland Consulting

Analysis of Section 50 of the Incentive for Energy Independence Act

Utility Interview Notes Based on Interviews Held in Frankfort, Kentucky December 17 - 20

Interviews Conducted by:

Howard Lubow, Overland Consulting
Steve Ostrover, London Economics

December 26, 2007

Energy Act – Section 50 Review
Summary of utility meetings
December 17-19, 2007

1. Kentucky Power (AEP)

December 17, 2007
1:00-4:00

Participants: Tim Mosher, President & COO; Errol Wagner, Director Regulatory Services; Judi Willis, Senior Regulatory Consultant; Mark Overstreet, attorney Stites & Harbison; Bruce Braine, VP Strategic Policy (by phone); Kristy Monk, Environmental Policy Specialist (by phone).

IRP Process

– believes that the current process should be maintained. CPCN process is formal, and addresses resource alternatives. There is no time limitation on these proceedings.

DSM

– "Collaborative" process; by class.
– Large industrial energy users may opt out of program. 10-15 customers. Other industrials have dropped out of DSM collaborative over the last 2-3 years due to lack of interest.
– Commercial programs went well for several years, but also stopped 2-3 years ago.
– There should be increased participation from industrials and commercials. They are driven by cost efficiencies, but conflict between plant operations and finance departments (focused on energy cost reductions).
– Residential Collaborative meets quarterly. Total Resource Test (TRT) must be 1 or better to consider programs. This process began about 10 years ago. The AG is a member of the collaborative; not GOEP.
– The current DSM Statute is adequate and works well. However, "capital costs' should be included. Historically, only O&M costs have been recovered. Current statute covers this.
– As an example, investments associated with "intelligent meters" should earn a return. Costs must be immediately deferred for ultimate recovery
– Procedures should be put in place to make the utility indifferent as to demand versus supply side resources. If there are investments in Smart Meters, the utility needs assurance of recovery, including carrying charges, until costs are reflected in rates.
– Expanded DSM will also require additional employees to run them. These costs must also be recovered.
– Some programs have high administrative costs, such as loans to install heat pumps. KP does not provide such programs at this time. Providing loans to customers for EE is too expensive.

- While additional incentives for utilities may induce additional DSM, KP wants to ensure that programs are cost-effective.
- The screening models recognize an avoided cost of capacity. Considers an IGCC project or GT as avoided capacity costs.
- DSM filings are made semi-annually. Collaboratives do the actual filing and meet with Staff.

Renewables.

- Currently have a net metering tariff for PV. Not really cost-effective. There are no customers on the tariff after over 3 years. While better than solar PV, even solar water heating is in the 12-15 cent range.
- Commission's authority to direct specific criteria for RPS must be based on statutory authority.
- Recommended that we review utility comments in 0300 case address, activities and Federal policies).
- Handed out October 9, 2007 presentation; portfolio diversification already through AEP; portfolio diversification for technology cost and energy cost risks, but they have accelerated some activities in face of climate issues. Formal development in strategy in last few years – see slide 7 – long term reduction portfolio. AEP and KP recognize future cap and trade CO_2 constraints. So AEP wants to become more diversified and reduce carbon footprint – DSM is part of this strategy, supply side efficiency (does not get much attention, but some positive developments - NSR settlement allows AEP to make incremental investments to expand capacity and reduce CO_2 rate and improve efficiency in Eastern fleet of plants); carbon capture, offsystem reductions, and R&D in carbon sequestration, and then fourth prong is renewables.
- AEP is part of voluntary program since 2003 – Chicago Climate Change – to reduce CO_2 emissions from their efficiency gains, some renewables in western part of AEP system (800 MW in Texas of wind), tree planting (offsets); they have goal to double wind (but not necessarily in just KY), AEP has made 1,000 MW commit (270 MW already filled up); wind is lowest cost of renewable options, but its also actively in demand (big back log on wind turbine supply)
- So they are looking at this on AEP portfolio basis to minimize costs, rather than just for KP – they want to take advantage of their entire service territory footprint Texas has 42% wind factor, and they have looked at 20% load factor projects)
- AEP also looking at various carbon solutions – example: flaring methane by covering manure lagoons at farms – carbon reduction; methane has 23x the global warming potential of carbon equivalent, created offset of 600,000 tons per year (deal announced in June 2007). Futuregen project (2012 schedule, but not yet final announcement on site – IL or TX at this point) – lots of partners; and other coal technologies; coal sequestration – CEO pushed them to build one rather than spend time to R&D process cycle, so AEP tested out carbon capture and storage – chilled ammonia, etc. They have a number of major projects going on, like enhanced oil recovery, etc. GHG mitigation costs illustrated in the slide pack – costs close to $50/ton. Slide 15 includes nuclear; AEP studying it because every option needs to be examined, and AEP has experience of nuclear plant, but there are many issues and divided stakeholder community when it comes to stakeholder development, but there seems to be movement towards acceptance as compared to a decade ago. AEP will be more of a follower than leader, because does not have a huge nuclear fleet (just the Cook plant). Statute 278.605 prohibits nuclear in KY for now – not much progress for storage.

- Bali – although US signed, it has lots of wiggle room in the language, 20% to 40% reductions, below 1990 levels by 2020. How can US meet that target? So need to develop on these technologies and commercially available, but that's 10-15 year process, including time for demos working, bugs ironed out, risk issues resolved, and permitting…
- Global warming is costly phenomenon, upfront capital, rate recovery questions remain, issues at both state and Federal level – institutional barriers and permitting standards.
- As part of IRP, they forecast capacity and energy needs in KY but as strategy, they don't really look at KP on isolated basis. And it matches the overall operations – it's all designed to operate on integrated, corporate basis, also part of PJM. So there are advantages to that – can bring in lower cost wind at attractive cost versus building wind in state of KY.
- Carbon legislation – "cap and trade" most likely. First response is to make existing plants more efficient.
- AEP system footprint is a plus for Kentucky; wind generation in Texas provides benefits to Kentucky.
- Current estimates for IGCC – 30% energy requirement for carbon recapture. 10-15% energy requirement for chilled ammonia. CO2 recapture cost -- $40-50/ton. This represents a 60-70% increase over new conventional plant costs.
- Nuclear – too many barriers. Expect that new units will be developed at existing sites. Major uncertainty as to expected capital costs.
- AEP is not in favor of an RPS standard. The federal "Production Tax Credit" provides major incentive for renewables; more than RPS. *The "Virginia Model" encourages renewables.* AEP likes the voluntary goals program in VA, if utility meets voluntary goals, then get additional return incentive; may need reasonableness guidelines rather than least cost then to get projects approved; very progressive
- Least cost and renewables probably not complementary in KY context, may need other language – for "economic development" or in "public interest"
- AEP has a "Green Energy" tariff, but not in Kentucky yet. It is 20%-40% energy price premium. Presently have about 2,000 customers (out of 1.2 million) on the tariff in Ohio. Easier to offer this in Ohio because of PJM market.
- KP presently has no IPP or merchant generation sourcing in Kentucky.

Full-Cost Accounting.

- Should only include direct applied costs. Societal costs are difficult to measure.

Rate Design.

- A voluntary "Real Time Pricing Tariff" is now pending. Currently have an on/off peak option, which does not have much customer interest. No one has signed up yet.
- Large Commercial TOU – conducted a 5 year study. Concluded that it was not worth the benefit.
- KPSC has broad regulatory authority. May authorize surcharges, as it deems appropriate.
- Voluntary tariff for "green" energy – a preferred approach because it will gauge the interest of ratepayers. This is likely to be similar to the one they have in Ohio. Customer must buy two 100 kWh block – 70 cents/kWh - $14 increase on a customer's bill (and some coops add - coop charges $20 premium); so far in Ohio, 2000 customers signed up out of 1.2 million; came out in August 2007.

Some of the revenues collected in the Buckeye Power program are paying for KY-based biomass IPP (Griffin Brothers, maybe?).

- KP is opposed to a public interest surcharge fund to redistribute revenues collected from tariffs collected based on full cost accounting levels in rates.
- Kentucky is a low income area; worried about impact on customers. Before taking any final position on a public interest surcharge, would like to understand level of ratepayer costs and anticipated benefits. Challenge is for the surcharge to meet the "fair and reasonable" standard, absent a specific statutory mandate.

2 Duke Energy

December 18, 2007
8:30-12:30

Participants: Richard Stevie, Managing Director, Customer Market Analytics; Paul Smith, VP Rates; Victor Needham, Manager, Regional Govt. Affairs; John Finnigan, Assoc. General Counsel; Jim Lefeld, Director, Alternative EnergyTed Schultz, Energy Efficiency; Mike Gribler, General Manager, Regulatory Affairs(by phone); Diane Jenner, Resource Planning (by phone).

- Preliminary comments regarding proposed "Save-A-Watt" program. Designed to develop energy efficiency. Creates utility incentives to develop and administer the programs, at its risk, based on avoided costs.
- Sections 50-55 of HB1 were included based on input from "Kentuckians for the Commonwealth – Tome Fitzgerald.
- The PSC could make the IRP process more formal. However, this would likely lead to less efficiency, as it would be redundant in light of the CPCN process. Duke is opposed to IRP standardization. Utilities within the state are different, and utilities need to address the needs of their customer based differently.
- To date, Duke has not really integrated DSM – model did not allow choice of generation versus conservation. Some minimal amount of DSM included and supply expanded after cost-effective DSM was utilized (20-30 Mw), which does not delay a power plant since they are built in much larger scale.
- Duke's IRP was also complicated by the transfer of ownership of generation from Ohio to Kentucky, which met their needs for power. There has been a lot of evolution since the 2004 IRP; due to file in July 2008. In the North Carolina and Indiana November 2007 IRP, the plan optimized between conservation and supply side resources.

DSM

- KPSC authority is broad, and includes ability to provide for financial incentives. This may be a good opportunity to make the PSC scope of authority more explicit.
- In general, a narrow definition or interpretation of PSC authority is a problem for utilities in that it creates regulatory and judicial uncertainty. The appeal process can take up to 10 years, and involves 3 steps for appellate review.
- DSM programs have been implemented since the mid-90s. Residential and low income customer interest continues. The Collaborative process works well. Residential programs focused on low income customers, and then expanded

incentives (refer to data request responses). They believe that they are success (customer satisfaction levels good); Collaborative process has been steady – AG's office, community based action groups, Legal Aid, Governor's Office of Energy Policy – process has worked well although not always smooth process. Typical process: pilot and Impact Valuation Studies. Some C&I programs were subscribed in 2 weeks – and Duke had to cutoff offering the program to others, because each year a certain set of budget funding approved by the Commission in the annual filing. They may need more flexibility so they don't wait until the following year to further the program.

- While the potential is great, acceptance is currently small. This is due to customer lack of expertise, time, or desire. Also due to lack of capital for up-front costs versus long-term NPV of benefits.
- Efficiency Savings Plan – Utility financing plan – at prime or prime minus.
- "Utilities must lead" in development of EE and DSM program expansion.
- 278.285 language could be expanded to directly address types of financial incentives for utilities. *Review the North Carolina statute.*
- Advanced metering equipment is an option that should be considered -- among other things, it would provide for greater control of on peak-use.
- Save-A-Watt program. As proposed, the utility is only paid for actual benefits produced. All incremental costs are to come out of revenues from avoided generation costs. (See DR response 6D) Duke proposes it be compensated based on revenues equal to 90% of avoided cost of generation. Duke is responsible for delivery of demand response equivalent. The fundamental difference with this program is that the utility is paid only for results that are produced, measured and verified by third-party. *New model paradigm: this shifts risk of participation and delivery to the utility from the customer.*
- The program has been proposed in North Carolina, based on enabling legislation *(Duke to provide a copy of the Statute).* The program is also now pending in South Carolina and Indiana. *(Duke also to provide testimony in other states, as it summarizes the EE program proposals).*
- Low income programs are not necessarily cost-effective; the utility pays all costs. EE programs currently have about 20% participation.
  Under the new approach, EE and DSM would be part of the customer standard offer tariff.
- DR changes from year to year, while EE is there once implemented typically. Duke mentioned 10x what they currently have as potential.
- In Kentucky, AG may paralyze the implementation of this program unless there is statutory change. AG is critical of the cost effectiveness of EE.
- Duke aggressively pursues DSM programs, including time differentiated pricing.
- "Energy Star" program – a complete home program. (N. Carolina, S. Carolina, Indiana)
- Financing for EE and DSM customer equipment is provided through banks as much as possible – terms include prime minus 1; non-pay disconnect.
- "Smart-Metering" Program is needed for next level of EE programs. Must have tracker recovery authority.
- Cost recovery mechanisms must be in place to bring about commitment and enhancement of EE and DSM programs.
- Industrial DSM – still many opportunities. Large customers should be entitled to opt out. All transmission level customers have opted out. However, no one should opt out of demand response programs. They don't believe that anyone

can opt-out from DR, since everyone needs to participate since that program is not based on individual efficiency but optimization of system use. They do believe that there are cases where customers can opt out because some clients are already very efficient. But it's a small number.

- Current DSM program benefit is about 20-30 Mw.
- Duke includes avoided cost of capacity based on peaker method; consistent with QF.
- The avoided cost includes the price for capacity based on peaker (regardless if the IRP said that they will not build for a few years – but then avoided energy cost should be lower because can rely on existing capacity) plus avoided marginal energy cost from IRP (which includes capacity costs?). They look at the IRP with and without EE – so in some hours, buy from market (higher energy cost, embedded in it some different capacity mixes, avoided capacity). IRP model determines timing of bundles of EE – the "great equalizer." This rate methodology demand a lot from IRP. Load shape with each EE measure will be differentiated. Does not view delay versus avoidance of investment in the same way – does not differentiate. The model is done in NPV basis.
- In future, they want to give customers more control over when energy is used as well as conservation – time differentiated prices will need to be included (smart devices, and simple interface with customer), but time differentiated does not need to be hourly – they are still studying the needs of customers, costs, and technology.
- Typically low income programs are not cost effective... except the equipment replacement (which works really well – pumps cut heating costs by 50%). The weatherization program is another low income program. Energy Star program – home performance program, looks at structure and appliances integrally. They do not finance, but facilitate the transaction. Financing terms change the cost effectiveness of the program. Duke acknowledges that there is an opportunity to get financing options in place. In Cincinnati, partnered with Wal-Mart and Sam's Club (open model) – get them to go out and purchase new appliances. Utility pays for their customers who took opportunity of the promotion. Utility knows the customers and can then go back and verify that the energy efficiency was employed. They are trying to also do this with banking. Low income – issue of rental stock, how to incentivize landlords without hurting tenants. Commercial sector – same problem for apartment building owners, although opportunity for EE is even larger.
- As a utility, they believe that the Commission has broad power and has adequate authority to address Section 50. For example, DSM Statute is very broad statute - KPSC can grant the company financial incentives (without explicit limitations) to utilities that bring forward beneficial DSM programs; but what is more important is what KPSC believes its authority. AG has taken narrow view – if its not explicit, than KPSC does not have authority (refer to case in appeals); appeal structure from PSC decisions – must first go to Trial level court, court of appeals, and then KY Supreme Court – builds in too much time and uncertainty (as much as ten years). Although Commission Orders are binding until overturned, appeals subject utility to recovery risk. This would be a good opportunity to make certain authority explicit – Commission should support modification to expand the language currently in there, list out financial incentives. New Governor was former AG and new AG (former energy policy advisor) could be engaged to reform the current statute. And Duke would recommend shortening up appeal

process for Commission decisions. There is simply too much uncertainty -- sometimes the assigned judges do not have the foundational background.

Renewables – *Should review utility comments in 2007-280; Energy Policy Act.*

- RPS would likely be challenged by various stakeholders. Duke is opposed to a Federal mandate; it should be left to the states.
- EE must come first. Renewables must take customer impacts into account. There should be a state-wide study, as there are major differences within the state. Rural versus urban differences need to be taken into consideration.

- The avoided cost of generation is a peaker; consistent with QF.
- Renewables are generally over avoided costs, while DSM is below avoided costs.
- There is a new wind assessment currently underway in Kentucky. However, transmission line access is also an issue.
- Duke currently has an RFP out in Indiana for 100 Mw of renewables.
- There is no need for additional incentives for renewables. Federal incentives for wind and solar are currently sufficient. There are also incentives in HB 1.
- However, the reliability of solar and wind is an issue; these are as-available resources.
- Currently screens renewables against each other. Resources are then considered against carbon constraint. There is a 15-20% PVRR premium for non-carbon to carbon case assumptions. If the scenario does not include carbon constraints, renewables typically is not chosen.
- Duke does look at RPS and carbon sensitivities, and renewables come in where policy mandates are reflected. This was shat was filed in the other states in November 2007. Two carbon scenarios – both based on proposed Bingham legislation -- safety valve carbon prices and market carbon prices in lieu of safety carbon (high carbon). High carbon tended to bring in more renewables; even a nuclear unit. Renewables tended to be more driven by assumptions on RPS. Carbon cases also included assumption of RPS. North Carolina has RPS; not yet in Indianabut they did use a legislative proposal from a 2006 session, and a 15% Federal standard sensitivity also ran.
- Construction of an IGCC Plant has been approved in Indiana. 600 Mw unit; cost is estimated at $1.985 billion, excluding sequestration. There is regulatory approval for recovery up to a cap, with risk-sharing thereafter.
- Carbon storage will require legislation to address long-term liability issues.
- Duke has no current plans for additional generating capacity in Kentucky.
- Distributed generation. Non-regulatory projects require local zoning; siting is by a statewide board. Hurdles are current natural gas prices; and operators generally do not want to get into the power generation business. In any event, not currently competitive against low-cost electric prices.

Full-Cost Accounting.

- Only looking at carbon at this time. Environmental costs included to date: SO2, Nox, mercury, and CO2.
- It is impossible to monetize health costs; "where do you stop".
- Believes that KPSC has the authority to employ full-cost accounting, but it is a bad idea.

- One must also keep in sight what customer is paying. FCA introduces a lot of speculation to the IRP if you employ it in making choices.
- Qualitative considerations could generally include environmental matters. Duke has never addressed health care costs or economic development.

Rates

- TOU is currently in place for large industrials only (over 500 Kw). Should be for all industrials, but this tariff is revenue neutral to the class. Given currently low average costs, there is not enough incentive.
- No seasonal rates – not efficient in moving peak; erodes energy; not capacity.
- The AG has historically not been supportive of EE programs in terms of cost recovery. The utility must have budget authority in rates.
- May need a generic Tracker statute for the Commission – so Commission can approve any surcharge for any utility costs -- this would help set the cost recovery framework for utility investment in smart metering, which will be necessary and useful in the area of energy efficiency. Need clarity in rules for cost recovery.
- The FAC should be changed to provide recovery of costs during forced outages. There is some risk in wind outages (unavailability). May be biased toward coal-fired generation. Needs clarification.
- Should incorporate "available generation", Tracker surcharges, TOU rates.
- A "System Benefits" charge is not appropriate at a statewide level; but would support a utility specific surcharge to support utility specific EE and DSM programs. There is some question as to whether this is legislatively possible, and what burden this would place on the Commission to manage such a fund.

3 East Kentucky Power

December 18, 2007
1:30-5:30

Participants: Charles Lile, Senior Corporate Counsel; James Lamb, Senior V.P. Power Supply; John Twitchell, Senior VP G&T Operations; William Bosta Manager, Pricing Process.

- Owned by 16 member distribution coops. 3,000 Mw system. 80-350 Mw each at the distribution coop level.
- PSC authority to consider alternative DSM programs – PSC currently has broad authority. Significant modification of DSM may require a modification of the statute.
- DSM focus is primarily residential.
  Largest customer is on an interruptible rate -- 130-140 mw.
- Residential programs – EKP coordinates programs. No collaboratives.
  EKP brings ideas to member systems. Coordinates DSM cost/benefit tests.
  Member coops are not required to implement EKP DSM; while they may develop their own programs.
- EKP has not invoked DSM surcharge. It has chosen not to come to the Commission for cost recovery through this surcharge. No large scale programs.
- Public power business model – no incentive to earn a return. Customers and owners are the same. As a result, looks at DSM as power supply.

- Uses DSManager – recognizes avoided capacity cost. Look at peaking/intermediate/base load as a measure of avoided capacity costs. Also takes in consideration the type of DSM program being measured.
- Regulatory process does not differentiate between small programs and larger ones for other utilities. Criteria and process in 278 is a good one. ***EKP believes that the Process should be expedited.*** Touchtone Energy Home project – took 9-10 months for approval. Program was already in place; just trying to extend credit incentives.

Renewables
- Should not require percentage mandates.
- Currently purchase hydro.
- Currently consider carbon in L-T planning. Power plant under construction in 2009. 278 Mw; 2 CT; coal plant -2012 -- 278 Mw. Alternative is probably a gas turbine.
- Currently considering a solicitation for renewables.
- 150 Mw wind project – EKP is evaluating 10%. Would be in Iowa. Transmission service is an issue.
- Transmission is a definite constraint. Problem of firm transmission – capacity and energy constrained. Recently importing 1,100 Mw of a 2,200 Mw demand. EKP is a major importer. Firm transmission is under contract across the state line. EKP is putting in 345 Kv backbone system.
- Eon issued an RFP earlier this year – got small and large responses.
- 11 Mw of methane.
- Current CPN process is fair.
- **IRP**, if formalized, would induce active intervention – environmentalists, etc. Would make it more difficult for the Commission. Timing issues; would duplicate work.
- The KPSC should look at Standards for Intervention.
- Renewables. EKP does solicit for projects -- a renewable vendor could make a bid.
- Portfolio analysis – some supply challenges to manage assets currently through PA. PA is used for developing hedging strategies.
- EKP gets 1 or 2 vendor calls per month for renewables. EKP gives consideration to such vendors.
- Renewable energy will come to Kentucky, as it is economically justified.
- EKP is currently looking for alternative fuels at coal plants – wood; looked at shredded tires, but higher in price than coal.
- EKP is modeling cap-and-trade in 2012 for carbon. Currently assume an estimate of a 20% premium on avoided costs.

Full-cost accounting.
- Difficult enough looking at direct factors. Scope of effort to do correctly would be enormous. Results may not have much value.
- Intervention denial – can appeal immediately. This would not create any real jeopardy.
- Sierra Club intervention – areas not contemplated by Commission.
- If consideration of "externalities" was legislated, intervenors will make proceedings much more difficult.

- "Kentucky Economic Development Cabinet" position supports least-cost power, while organizations like the Sierra Club argue that Kentucky's power is much more expensive than implied by current rates.

Rate Structures

- Commission has broad authority.
- Fuel Adjustment Clause – total costs over base/kwh base. Why not have 6 mos. Levelized costs. It is simple, and works well. Due to lags, costs do not reflect current costs when applied to billings.
- Variations cause cash flow issues for distribution coops, and retail customer problems.
- Because EKP is a residential coop -- more volatile.
- DSM can be accomplished through interruptible and real time rates. They are awaiting approval on the real time rate right now and looking forward to potential of broader implementation.
- Currently offer rebates for EE programs. Implicit or embedded in base rates. Also provide free residential energy audits.
- In terms of regulatory oversite and authority, not much is lacking at this time.
- There are good reasons why DSM first came to New England and renewables to California -- but EKP believes everyone will agree that such programs are coming elsewhere. EKP would prefer that it comes rationally and logically rather than artificially. Kentucky will be better off.
- Charles Lile – primary contact for informal questions.

4 Big Rivers Electric Coop.

December 19, 2007
11:30-3:30

Participants: Tyson Kamuf – attorney with Sullivan Mountjoy Stainback & Miller; Mike Mattox, Manager Resource Planning; Russ Pogue, Manager Marketing& Member Relations; Mike Core, President/CEO; David Spainhoward – V.P. External Relations

- There are 3 member coops. 110,000 meters. Distribution members have all-power requirements contracts. Big Rivers has an 80%+ load factor. Two major 100% load factor customers.

DSM program modifications

- PSC authority is currently sufficient.
- Big Rivers coordinates IRP and DSM screening models. Current: EE; incentive programs. Light bulbs, education of energy conservation; touchstone energy homes.
- Collaborate with members. Will invite Kentucky DOE – doesn't come. AG participates. Parties participate in IRP process. Not otherwise much involvement in process from outside parties.
- Distribution coops can implement DSM programs individually.
- Does meet with Energy Efficiency working group – monthly meetings.
- Information is distributed to customers re EE, pilot programs.

- 61 Mw reduction from cogen and conservation. _(David will provide a breakdown)._
- Big Rivers does not participate in DSM surcharge; costs go through base rates.
- Industrial curtailment program – interruptible customers on tariff. Negotiate event by event basis. Also have interruptible contracts – since about 2004.
- Industrial opt out provision is a non-issue, as they currently do not pass through costs of DSM in the surcharge.
- BR views conservation as the "cheapest" new resource – because it represents existing capacity that is not utilized and if it's on the system, that implies it was cost effective.
- DSM Screening Model – doesn't know if avoided capacity is recognized.
- Current policies and practices are adequate re PSC regulations.
- 9 coal fired units; 1 CT. Due to high load factor, avoided capacity is a base load unit.

Renewables.

- Current renewable project: Biomass at paper mill – 50Mw; cogeneration. 2001. May be expanded. No excess is ever put on the grid. Metering and interconnection requirements would be different; not currently in place.
- Landfill operators; ethanol plant to use steam; others do contact. If it makes sense, Big Rivers will consider renewables.
- CPCN process – Big Rivers supports the current process.
- IRP process should NOT change.
- Externalities – carbon tax – should be considered when known.
- Argument of "more teeth" in PSC enforcement – current mechanisms do currently work.
- Parties – AG; KDOE; smelters. No environmental or low-income groups.
- RPS – needs to be realistic. California is 20% by 2010 – not likely. This is an energy standard. Costs are likely to go up, if implemented. Will cause unemployment in coal mining industry.
- This much energy in volume is also a transmission issue.
- G&T association is currently looking at a "Nat.l Coop for RPS".
- EE must be tied to EE products in manufacturing. Federal legislation.
  1 in 3 houses are manufactured housing in rural Kentucky. Insulation has relatively fast payback. Lack of participants – ignorance; low-income. Loans on manufactured homes are 7-10 years.
- 3rd party banks not interested in funding EE.
- First Kentucky Energy Expo – 2007. 700 people showed up, which was a very positive turnout relative to expectations. Must educate people. More important than legislation.

Full-cost accounting

- Carbon impacts – not currently considered. Current estimate is a 20-50% premium on generation costs. Base case 30-35%.
- Looking at making units more efficient – improve heat rates.

Rate structure options.

- Coop model is to protect the customer. Concern is always the end-user.
- Public good surcharge – where does money go, what is it used for.
- If invested in new technologies; loan programs – may be willing to support this.

- Donate CLFs. Subsidize heat pumps. Preference would be to allow utility to make these investments – not through state agencies.
  – Surcharges can be created under current statutory authority – under existing framework. BUT – there is a statute to support coal; also what if programs result in higher than "lowest reasonable cost".
- At present, no TOU rates. Based on current low costs, not much incentive to shift rates.
- Smart meters – not in near future at Big Rivers. LG&E has pilot program.
- Incentives are better than mandates. For Big Rivers, the incentive is the avoided cost of capacity. There will be incremental administrative costs. Need to educate energy equipment vendors.
- Energy Star equivalent home -- $1,800. incremental cost. Payback is about 3 years. Most homebuilders not building them, because customers are not requesting it. Building code standards—compliance, enforcement.
- Advertising is not currently allowed in rates. This is very restrictive in Kentucky – AG always argues for disallowance. Need to agree on guidelines.
- Low-income customers are also a concern and an issue. Look at current Energy Assistance program customers. Exempt them out.

5 Eon – LG&E/KU

December 20, 2007
9:00-12:15

Participants: David Sinclair – Director Energy Planning, Analysis & Forecasting; Doug Schetzel – Director Business Development; John Wolfram – Director Customer Service & Marketing; Dan Arbough – Director Corporate Finance and Treasurer; Kent Blake, VP Corporate Planning & Development; Lonnie Bellar, VP State Regulation & Rates; Rick Lovekamp, Manager, Regulatory Affairs; Allyson Sturgeon, Senior Corporate Attorney

Rick Lovekamp – may contact for informal discussion.

Eon provided a presentation addressing the subject matter of interview questions previously submitted:

- Eon is the largest IOU in the state.
- High customer satisfaction.
- Kentucky was lowest cost state in 2005; not 2006.
- Resource planning is performed annually; not just every 3 years for PSC filings. Nest IRP due April 2008.
- Forecast approximately 1.8% (LGE)/1.9% (KU) growth rates, exclusive of DSM.
- Currently building a 700+ Mw coal plant – to come on in 2010. (Trimble 2)
- Currently rehabilitating a hydro project – increase capacity from 80-100 MW.

Business profile system has recently changed at S&P.

- Eon has a major interest and commitment in FutureGen project.
- Carbon legislation is coming; will most likely to cap and trade. **Carbon output is put on customer bills.**
- Consumer education is important.

- Eon Climate and Renewables – just bought a Wind company in Illinois.
- Active RFP process for renewables. – Copy provided in discovery.
- Expect to triple DSM/EE (page 18)
- ICF report – shows relative spending levels on DSM. (See discovery)
- Regulatory Certainty is important.

IRP Process

- Preference is at the utility planning level. Doesn't want to be tied to statewide planning. Eon IRPs look at known and unknown factors.
- Climate change is now a bigger issue. More to look at now -- Considers Europe.
- Impacts may be beyond just DSM standards.
- Generation – review technologies.
- No value to statewide planning if there is a two-year lag from utility level planning.
- In 2005 IRP, AG and low-income advocates. K Div. of Energy did not intervene.

DSM Advisory Group

- Energy Efficiency Advisory Group – invite AG; low-income groups; and KY Dept. of Energy. Normally groups are subject to invitation.
- IRP must be consistent with policy and regulation.

- CO2 was considered in 2005 IRP. The 2008 IRP will have more information and analysis on climate change. Carbon not in base case, which is based on existing legislation, but will have alternate case scenarios. There will also be a different look at load side for EE technologies and what that means, and consumer behavior changes. DSM is allowed to compete with supply side resources.
- Current IRP processes; CPCN are adequate.
- IRP is just part of good business planning. The process, if changed, should not adversely affect good business planning.
- DSM process – ICF retained to look at DSM process. Good process vs. many other states. For utilities -- Not currently an equal incentive vs. generation investment. Customer interest – based on economics and education.
- Eon will address, in testimony, utility incentives for investment in EE / DSM. Extensive investment in smart metering.
- Commission has broad regulatory authority in implement surcharges, etc. Concern is where broad policy changes.
- EE filing is currently pending at the commission.
- Currently spend about $9.5 million per year; looking at spending $25 million – includes education programs. New programs will also include Residential High Efficiency Lighting; Residential New Construction; Residential & Comm'l. HVAC; Deal Referral Network.
- Avoided capacity cost – weighted average of expected portfolio.
- DSM – Industrial customers. All customers have opted out. Screened out based on survey. Even smaller users do manage their energy loads. They do not want to support DSM for other customers. Customers seem to want 1 year payback.

Renewables.

- Targeted renewable percentages – excluding hydro; limited resources. To develop renewables in Kentucky will increase costs. First 5% is less costly than higher levels.

- Eon has also looked at a renewable tax – 5% on all generation. This could be more efficient. For global climate change, it does not matter whether the renewables are in Kentucky or elsewhere around the US or the world.
- Renewables already promoted through several regs: KRS 278.466 – enacted to promote the use of small scale renewables by residential and commercial customers and 807 KAR 5:054 – to encourage cogeneration and small power production.
- Biggest commitment for CO2 is to Futuregen – just announced it will be in Illinois.
- Renewables RFP – received 16 bids. Intend to meet with high potential viability proposals. Volumes are not large. Site specific.
- Also looked at self-build opportunities in state. Pursued hydro over last two years, but Municipalities, in federal law, get a preference re hydo license.
- Wind is limited, but Eon is looking at it.
- Biomass – limited. Paper mills, others currently use waste products. Utilities could pull from existing use – leads to higher costs.
- Renewables are limited, and has high cost.
- Nuclear power – must be considered. New units at existing nuclear stations are likely to be the initial sites. There were some studies in the 1970s where KU looked at sites for nuclear (near Trimble County).
- Three nuclear applications now pending : Dominion, NRG, Duke.

- Carbon costs in last IRP -- $/ton sensitivity. Also in CPCN. However, Base IRP is on existing regulation.

Full Cost Accounting.
- "Commission does not have jurisdiction under KRS Chapter 278 to explicitly allow for consideration of externalities in the price of electricity." See page 50, Kentucky's Electric Infrastructure: Present and Future, Executive Order No. 2005-000121. (Slide 21)
- Eon continues to look at alternative scenarios in the IRP and investment planning process.
- Technologies that can actually be permitted influence what costs are considered in the planning process.

Rate Design
- E.On proposes that it would be beneficial to allow utilities to fully recover costs for investments pre-approved under the current CPCN process to reduce uncertainty. (see Case No. 2005-00090, Order dated September 15, 2005, Appendix B, page 103 (Slide 22))
- TOU rates – large comm'l; industrial only.

Response Pricing & Smart Metering pilot program.
- 3 year program -- just starting up now. 2-way communication. Options: Critical peak pricing component. 1% of year – super pricing. Options include – load control; TOU programs. Currently can do this in DSM.
- Rewards only program. No penalties. If no change in usage, customer will pay the same as current rates; revenue neutral.
- In-home display – shows consumption; costs. Provides a lot of information.
- Programmable thermostat based on pricing period. Can program to avoid super-critical costs.

- Should show what drives behavior: economics, information.
- Customer pays $5/month – for pilot program.
- $1.9 million over 3 years (Case #2007-00117)
- 85%+ of time, the rate would be lower than standard tariff.
- 100,000 customers currently on load-control – over 100Mw saved.
- Small comm'l. TOD rate. Encourages load shifting. Not much response. Grocery stores.
- Interruptible load – less than 60 Mw. Differential is not great enough to tolerate interruption. Value of item produced vs. value of curtailment.
- DSM Program costs are now spread over the applicable class.
- Solar water heating – 86 year payback. Maybe there should be more pilot programs.
- Residential – High Efficiency lighting.
- Currently has proposed funding for 3rd party education programs.
- With broader criteria, more projects may to justified.
- Current DSM filings – low income weatherization program – low income groups want to run the programs; AG also challenges – dispute value of load control program – 115 Mw saved; different cost-benefit analysis; disputing educational advertising. No incentive or lost revenue recovery. (2007 – 319) 3rd party vender process may be ok – but use RFP process. Hearings are January 9.
- No DSM Orders have been appealed to date. Process itself will not discourage the filings.
- DSM surcharge – allocates costs over a particular class only. In doing otherwise, industrials would object.
- Eon class cost of service – residential load does not hit system average return.
- No lifeline rate – Home Energy Assistance program.
- HB 1 – could produce $300-$400 million benefit in gas produced from Kentucky coal.
- Analysis focuses on quantifiable information. Current costs are captured. Societal costs are not considered.
- There will be a CPN filing within the next 3 years. Carbon can impact generation sourcing. What can you actually get a permit for. Base load lead time 1 year planning; 2 years permitting; 3-4 years construction. All aside from transmission.
- Net metering – only three customers currently on this tariff.
- Growth is driving about 150 Mw per year need; expect to get about 300-400 Mw DSM.

Overland Consulting

Analysis of Section 50 of the Incentive for Energy Independence Act

Non-Utility Stakeholder Interview Notes Based on Interviews Held in Frankfort, Kentucky December 5-7

Interviews Conducted by:

Howard Lubow, Overland Consulting
Julia Frayer, London Economics
Bridgett Neely, London Economics

December 13, 2007

Energy Act – Section 50 Review
Summary of non-utility stakeholder meetings
December 5-7, 2007

1 December 5, 2007 1 PM

Participants: Metro Human Needs (Marlon Cummings); POWER (Robert Crutcher); Legal Aid Society (Lisa Kilkelly); and David Brown Kinloch

Background and interest of participants:

- Legal Aid is a community development organization which represents low income people in civil proceedings. Their main interest in this proceeding is ensuring that the low income segment has access to affordable utility service. They will monitor the process but unsure if they will intervene or file testimony.
- Metro Human Needs is a crisis intervention organization geared as supporting low income families. Again, their main interest in this proceeding is ensuring that low income segment has access to affordable utility service. They will monitor the process but unsure if they will intervene or file testimony.
- POWER is involved in LIHEAP and other similar programs. They will monitor the process but unsure if they will intervene or file testimony.
- David Brown Kinloch will be representing interests of small IPPs and renewables in the state, though he has previous experience working as a consultant for the Attorney General on IRP proceedings. He plans on intervening in the process.

General views about Section 50:

- Legal Aid: Their main concern is how changes will affect low income people. If implementing Section 50 will increase costs, the PSC needs to also factor in how this will affect vulnerable customers. Also, if the programs offer opportunities for DSM, low income customers should also be able to participate in similar programs.
- Metro Human Needs: How do you pay for it? Who has access to it?
- POWER: there should be more aggressive renewables and DSM programs. The utilities don't seem interested in these programs.
- Kinloch: there is an institutional bias against these kinds of programs at the PSC which would need to be overcome in order to implement Section 50 effectively.

Views about IRP process:

- POWER: the ultimate decision is up the utilities. The PSC has "no teeth." Statewide IRP planning might help if the PSC had more power.
- Kinloch: IRP process was reworked in the 1990s and now has no teeth. DSM is not taken seriously by anyone, including PSC and utilities. Requirements on DSM are just an administrative hoop.

- Utilities always seem to win RFPs for new plants. Utilities run these RFPs without any outside oversight.

Views about DSM programs – current and future:

- Metro Human Needs: For low income people the main issue is that the costs of these programs are socialized but low income customers usually don't benefit from the programs. It also appears to be a conflict of interest that the utilities are in charge of their DSM programs since they are in the business of selling power. PSC should be working on behalf of ratepayers, but it is not clear that it is doing so.
- POWER: PSC should have more input about utility DSM programs; current role is simply advisory but more authority is needed.
- Kinloch: Even the definition of DSM is questionable in KY: "load building" qualifies as DSM. The utilities try to avoid any energy reductions and only implement programs that shift an equal (if not more) amount of load to another time. There should be a lot of low hanging fruit in the state as there have been no real DSM programs and industry has been premised on the assumption of cheap electricity. PSC needs to have "more muscle" in its dealings with the utilities. PSC has statutory authority but doesn't want to use it.

Views about portfolio diversification:

- Kinloch: there is major potential for renewables in the state. The PSC is not only unhelpful in getting these developed, they have made the situation worse. It is next to impossible to develop any renewables under the PSC-approved avoided costs for the utilities – about 2.5 c/kWh. Utilities have no incentives to develop renewables. Independents are hampered because of inability to sell power (low avoided costs means no PURPA contract and net metering only allowed up to 20 kW for solar technologies only). Moreover, coal has subsidies (KY coal only). If renewables were playing on a level playing field, they would not require any additional subsidies.

Views on full cost accounting:

- Full environmental costs of coal plants, including potential for CO2 regulations, should be considered during IRP process
- Broader regional impact of reducing environmental emissions should be considered in analysis though it should not solely determine decisions.
- Externalities should be valued statewide and on an independent basis. The utilities cannot be trusted with this analysis.
- Impact of potential for layoffs etc is too complicated to integrate.

Views on rate structures:

- Currently the state has flat block rates. Transitioning to inclining block rates would help achieve some conservation overall.

- Utilities should not be allowed to put lots of charges in the monthly customer charge as they have been doing recently as this does not support efforts to reduce demand.
- The fuel and environmental surcharges are ridiculous. They allow the utilities to pass on costs with no examination of these costs. The environmental surcharges are particularly egregious: utilities don't have to be responsible for their planning decisions as they are fully compensated afterward. The full cost of using coal is not factored in the IRP process.

2 December 5, 2007 4 PM

Participants: KY Coal Association (Bill Caylor); West KY Coal Association (Kim Nelson); and one person who was not listed on the agenda and who had no card.

- Support Section 50 and efforts to reduce demand and increase the amount of renewables in the state.
- Coal is however an important part of meeting electricity demand in the state and in this country.
- Environmental emissions are the utilities' problem. Utilities will only make changes when they are forced to.
- The implementation of Section 50 will have no impact on coal production.
- Many allegations about coal industry are false. The science behind statements about greenhouse gases is not solid. Forest fires in CA cause more environmental pollution than the coal industry.
- They would recommend that the utilities publish how much of each utilities' power is generated by coal. They want customers to understand that coal-generated electricity is cheap and that implementing environmental regulations or replacing coal with renewables will dramatically increase costs for consumers.
- If the state wants to use full cost accounting, then it should look at both the costs and the benefits side. I.e., if you are going to add the cost of pollution and health issues, that you should also look at the number of jobs that coal offers, etc.
- The coal industry will not be hit if KY changes its policies toward coal fired electricity. It is the energy intensive industries (like steel and aluminum) who are based in KY for the low cost electricity that will shut down. Coal industry can always export its coal to other states and other countries.

3 December 6, 2007 8:30 AM

Participant: Louisville Cleanenergy (Bill Bivins)

- Participant is a start-up contractor, developing renewables applications. He has no plants in operation to date.
- Cleanenergy has a technology that will create electricity and natural gas from sewage and waste.

- Cleanenergy wants to locate the first project in KY but has encountered major problems.
- There is a huge potential for renewables in KY due to the amount of agriculture in the state. There is a University of Tennessee study about the opportunities for renewables in the Southeast and KY came out as having the highest potential.
- Tried to meet with the Governor's Chief of Staff but no interest at all.
- The Office of Energy Policy gave him a small grant for a feasibility study.
- His generic template is for the development of 10 mw facilities, employing approximately 50 people. Up to 50 mw units can be designed.
- Negotiated with E.On to contract the facility for several months. Cleanenergy needs to sell the excess on-peak energy back to the grid to make the project profitable. E.On initially offered 1.2 c/kWh, eventually negotiated up to 2.5 c/kWh which E.On claimed was its avoided costs even though E.On's IRP states that its wholesale cost of energy is 4 c/kWh. Eventually the deal failed because the contractual requirements that E.On wanted were so rigorous that the contract would no longer be profitable. E.On sells green electricity at a 4 c/kWh premium to regular electricity.
- Has had better interaction with East Kentucky Power, whose avoided costs are 5 c/kWh. They are still negotiating but will likely come to some agreement.
- Big River Coop appears interested but they have not had any meetings yet.
- Experience with natural gas sector has been much better. Easier to sell gas at market based rates without a hassle.
- Objectives behind Section 50 are good but in the meantime he is still stuck with incumbent generators who do not want to contract.
- DSM programs in the state seem focused on reducing peak demand rather than energy. Other states seem to have lots of programs that reduce overall energy (ex CA) by offering 0% interest loans to buy new energy efficient equipment. DSM programs "seem more like PR than a real attempt to reduce demand."
- A great organization in KY is the Kentucky Renewable Coalition (contact: Cam Metcalfe),which is run out of the University of Louisville. They do free commercial energy reviews throughout the state to help business reduce their demand. This is more helpful than any of the programs run by the utilities.
- It would be much better if the state could do planning on a statewide basis as you could then optimize renewable planning (i.e. 19 landfill sites not utilized)

4 December 6, 2007 8:30 AM

Participant: KY Association for Community Action (Kip Bomar)

- He will monitor process, but doubts that they will intervene, so long as needs of lower income consumers are being addressed
- He asked consultants about renewable potential in state, as he was unaware of any statistics on that.

- According to him, 16% of population are below the Federal poverty line, and poverty is both an urban and rural problem in KY
- He indicated that utility costs are the 3rd leading cause of homelessness.
- For the assistance that they provide, the thresholds are 130% of Federal poverty threshold (low income subsidy and crisis program) or 150% of threshold (weatherization program – insulate homes); the subsidy is more popular with customers than the weatherization program
- KPSC has statutory authority to do energy assistance programs for electric and gas according to Kip.
- To his knowledge, utilities do not have special low income rates currently.
- Some of the utility programs are partnered with federal weatherization program.
- Weatherization initiatives taken typically by those who own, as landlords do not like to take on obligations of those programs (which include promising to not raise the rent for some time)
- DSM for residential consumers revolves around which "test" applied – he believes that no single test should be determining factor; or the results for particular customer; rather the portfolio of DSM should pass as a whole to be accepted.
- He is happy with Commission work to date in scrutinizing the utility DSM programs, but recommends one improvement – faster approval process.
- His organization has intervened in rate cases , and has noted success in a rate case, where the utility has agreed to put in shareholder money to help with Energy Assistance program.
- He is against pre-paid meters because they can be remotely shut off when payment runs out and disconnections are so automated that they do not give the same opportunity to customer to pay off their bill, nor are they monitored/tracked as well as current disconnections.
- He indicated that Kentucky has a high disconnect rate – about 9.5%, versus a 3-4% rate for most states.
- He thought technologies like programmable thermostat would be useful for his constituents, if they are educated on use.
- Even $10/month savings can mean a lot for low-income consumers – that could be targeted for new DSM programs.
- He believes that many KY constituents believe that public health is not harmed by coal, so including public health consequences in FCA may be problematic.
- Nuclear as a renewable is only viable if recycling of fuel improved (in fact, moratorium will be lifted only after Yucca Mountain issues are resolved).
- Renewables currently face obstacles of contracts – low avoided cost calculated by utilities, and capacity components rare, so renewables by IPPs are difficult to rationalize.
- He believes that, absent an explicit statement of authority, the KPSC is probably not able to expand DSM or renewables. There is no present authority over non-utility parties.
- He believes that KU and LGE are planning to triple their DSM portfolio
- He likes concept of public good surcharge, especially if its not only to fund R&D but also help fund low income assistance programs.
- If rates increase due to DSM or renewables programs, he believes that the KPSC should consider lifeline rates to offset the effect on low-income customers.

- He stated his belief that the KPSC has done a good job to date in considering all stakeholder concerns.

5 December 6, 2007 2:00 PM

Participant: KY Chapter Sierra Club, KY Resources Council, KY Solar Energy Partnership; Sun Believable Services (Andy MacDonald, Joshua Bills, Dick Shore, Wallace McMullen, Ray Barry, Steve Sanders, Rick Cluett)

- They provided written commentary, which they then referred to throughout the meeting.
- They are interested in participating (like utilities' discovery request information and the utilities' responses to interrogatories) but cannot meet the schedule, not enough resources to respond to interrogatories, etc.
- They may wish to provide additional information. Overland explained that if it is to be considered in its report, any information must be provided by not later than December 31.
- One of the representatives was surprised that no one mentioned Global Warming in the question list and they think carbon caps are key issue.

- They believe that major barriers are rate structures, DSM/EE rates, as well as metering and interconnection policies; for example, net metering capped at 15 kW and only applicable to solar.
- Their view is that incentives are not currently adequate for renewables.
- They believe that the current IRP process is not good; thus, the planning and approval process is not good.
- They believed that possible sources to fund renewables and DSM projects could include and KY sales tax. They also supported encouraging utilities to pay the upfront costs of customer-based programs.
- They support green-generation pricing programs. They mentioned TVA's program. Customers could be paid for clean-energy.
- They believe uncoupling income from energy sales may be worth considering, but are aware of practical implementation issues. They mentioned 'statistical decoupling' but did not expand on that (noted that another stakeholder tomorrow would likely go into this method with us in detail)
- There is a divergence in how each utility implements net metering and this has created obstacles for renewable DG initiatives, like solar panels.
- They are critical of peak shifting that is classified as DSM, they don't believe it is appropriate to pursue.
- According to Sierra members, the potential are renewables is substantial: cogeneration, distributed hydroelectric generation, solar, biomass; they brought up the value of RECs that these resources would generate – and the value that they can sell in national 'green' marketplace.
- They championed especially solar water heaters and described to us the pilot they had to promote this - $500 credit off installation (cost of $4200 on average

for 2-4 person residence) and interest free loan program (in Eastern KY only); they have observed interest in PV even without rebates, but believe interest could be expanded with moderate incentives, like rebate funded by system benefits charge or sales tax rebate, or via partnerships with TVA, or even with incentives – like giving customers payment for all solar generated electricity not just the net metered amount at some special rate (they threw out 15 cents/kWh as reasonable for solar), and then charge for usage based on utility base rate.

- Another model to consider – incentivize final end users to go out and find commercial DSM and DG vendors.
- They mentioned that net metering and interconnection standards need to be made uniform.
- They suggested that the IRP process be more formalized, and that "California criteria" – societal costs should be recognized. Any consideration of these costs would be an improvement to the current KY process.
- They believe that standardized models should be employed in measuring costs and benefits. They agreed that some factors could be considered qualitatively. They also agreed that ranges of estimates could be used.
- They mentioned an Eon RFP for 750 Mw of renewable power.
- Generally in support of full cost recovery, although they were not as concerned that the scale for measuring benefits should equal that of costs (in-state benefits versus out-of-state benefits)
- They believed that the public health costs of KY generation must be recognized.
- They referred to August 2007 study that shows industrial efficiency programs cost 3.5 cents/kWh, while solar hot water projects are viable at 5 cents/kWh (without tax credits) taking into account only $1000 of maintenance costs and 25 year life span.
- According to them, IRPs do not include DG right now, but should; for example, unlikely that DG equipment would be deemed prudent capex in current regulatory context.
- Education of consumers is also inadequate – customers do not value conservation, but that can change through better customer relations and KPSC can help, leverage what it did with education of consumers on rising fuel costs
- One constituent at the meeting stated that he believes that current DSM rider is insufficient because does not include return.
- Except for biomass, capacity for large scale renewables not substantial in state; and interconnection at whim of utility for merchant renewables (utilities can drag their feet and policies for charging and cost allocation are not codified)
- Critical of opt-out for DSM for industrials – industrials do not need to prove that they have done their own EE
- Coal gasification is unknown because sequestration not yet proven in KY on industry scale; nuclear should not be renewable since lots of fossil fuel burned to produce the nuclear fuel.

- KPSC has statutory authority to look at environmental costs outside state borders because lawsuits mean that eventually KY utilities pay and consumers pay. This should be basis to consider costs/benefits that are wider than just state borders.
- Like the idea of a statewide IRP;
- Proposed leasing by utility of equipment to facilitate DG and renewables: utilities buy renewable equipment and install on DG basis – customer therefore does not own and not pay for it; the capex is in the utility ratebase.
- They are opposed to the addition of new generating capacity for the purpose of exporting power outside of the state.

6 December 7, 2007 8:30 AM

Participant: KY Association of Manufacturers (Hank List)

- Does not plan to intervene in these proceedings.
- Organization represents both the major utilities and many manufacturing concerns; personally, Hank, has been involved with energy issues in the state for many years.
- KPSC has statutory authority to encourage certain policies but cannot eliminate impediments. Specifically, DSM – does not have authority; encourage diversification – yes; full-cost accounting – no; expand rate design – no.
- He supports the consideration of all reasonable diversification options.
- Hank believes full cost accounting should not be pursued – this gives too much opportunity to challenge coal, it's a "variable with no cap" (referring to public health issues, and ecological issues – how to put price tag on mountain top removal) – its not role of PSC to decide if this is good or bad, not a regulatory duty but policy decision and he believes KPSC does not have policymaking capacity; FCA can be subjective; if FCA is not nationally-imposed, than why should it be imposed on just KY.
- Utilities should take into account costs of compliance once rules in place (i.e., GHG); with GHG, the problem is that there is no cost-effective technology to remove CO2, he suggests that regulators require tracking for now and educate consumers to make them aware of their GHG footprint, so when costs are imposed, they are better prepared.
- Likely that Federal regulations on GHG will come to fruition in next few years.
- For large users, the issue is whether they will continue to do business in KY; responding to national regulatory changes is best in that regard – because then KY is still relatively low cost (if all states face compliance costs).
- He believe that the KPSC has been helpful in supporting utilities in educating consumers about energy use.
- According to Hank, KY is in the investment/construction phase and utilities should be taking carbon into account (building so they can retrofit later).
- If new technologies are to be considered, the increased risks of such projects must be addressed by statutory support for generators.

- IRP is best place to deal with looming environmental costs rather than in rate design
- According to hank, KPSC has authority to modify rates but cannot require energy efficiency (can't tell builders how they build or tell consumers what light bulbs to use); KPSC also has authority to impose time of use rates
- Utilities should not be in R&D business – hank believes that public opposes the recovery of such expenses in rates
- According to Hank, there is not much DSM in KY, E.On is on the forefront but he is not aware of what is being done in Northern or Eastern KY; and he believes that industry has not done much.
- To the extent that his organization's members are doing EE, they do it for the Public Relations benefit or for the direct cost savings.
- There is very little cogen currently in KY because of the low rates, and very little DG because the PSC has not allowed cross-subsidization between ratepayer classes – and he believes that the approach to date is fair, because ratepayers are not paying for another customer's DG.
- He views conservation as a delayed investment problem – can never avoid building more generation, but can delay investment, and that has both benefits and costs (one cost if the inflation on equipment cost)
- To his knowledge, only one commercial wind farm in state and Big Black Mountain (optimal site) cannot be used due to environmental issues; no effective place for utility-scale renewables; water is everywhere but in small scale and many perceived disincentives to develop small hydro (fisheries; hydro impact on system reliability); DG renewables possible but not done yet in organized fashion: biomass is one renewable with potential
- Before KPSC condones subsidies, Hank believes an integrated plan needs to be in place with reasonable and achievable goals, and typically subsidies are done through laws (by legislature) rather than through regulation, so he questions KPSC's authority
- Low rates in KY is not a an accident but a result of careful management by Legislature and KPSC not to over-extend the obligations on the utilities to the detriment of ratepayers.
- Siting is not an obstacle, but it's the physical requirement of the permitting and building process – interconnecting (other networks, MISO and PJM, negatively impacting capacity on KY's system), ecological issues (can't build on KY River), and water availability for cooling.
- Need better policies for figuring out where to put new resources and encourage partnering between utilities to take advantage of economies of scale; Hank is proponent of statewide IRP, and reiterated need for Comprehensive state energy plan driven by legislation.
- The PSC could play a role in getting all parties together to develop best practices policies for the State.

7 December 7, 2007 10:00 AM

Participant: KY Industrial Utility Customers (Mike Kurtz)

- Will intervene and have witnesses.
- He represents the biggest electricity users in the state, 36 members, aluminum smelters, Toyota, Ford.
- Mike believes that PSC has statutory authority under DSM regulations to formulate DSM but PSC cannot impact impediments; PSC can encourage change through IRP, management audits but cannot mandate it; PSC needs more authority to consider externalities and therefore cannot incorporate FCA into rate design (this has never been done before in KY and any departure from standard practice will be scrutinized, even if PSC claims it has broad authority in setting just and reasonable rates).
- Mike was concerned with FCA and what it means – did not understand FCA terms – and thinks cost-benefit analysis that stretches beyond costs of generation and energy savings is slippery slope – and its an issue of social policy rather than regulation; he believes that FCA and cost-benefit analysis that looks at environmental issues is tantamount to PSC questioning what the DEP and EPA has determined as "compliance thresholds" – if plant is in compliance, then there is no question of whether it or others can do better.
- Utility would be unwise if it is not considering carbon issues already; he thinks strong likelihood that some regulation will be imposed (nationally) soon.
- Environmental costs is hard number to estimate according to Mike, its measurable but there may be arguments over method (NPV) and assumptions (future allowance prices and compliance levels).
- He does not want public health considered because utilities already comply with requirements (see above, about PSC substituting for judgment of EPA).
- PSC has discretion over rate design but it has also been told to deal exclusively with base rates, environmental surcharge, DSM surcharge and Fuel Adjustment Clause – new surcharges (like R&D) will need legislative change, but some costs can be treated within base rate and then PSC has authority to make changes (although departure from current practices will be questioned and possibly appealed).
- Even with new DSM, utilities will run coal just as much and simply make increased off-system sales, so there is no reduction in emissions (since AEP is only utility that shares profits of off-system sales on going basis with customers) – for other utilities, the assumption on volume of off-system revenues is in base rates, but does not change between rate cases.
- IRP should be improved, regulation puts PSC in advisory role with respect to IRP, but then PSC has more control in the siting process to get new resources certified (more control for regulated utilities than for merchants, as the board for merchants also include non-PSC members).

- If PSC wants to mandate in IRP, changes to statute needed according to Mike; even in certificate process, PSC can reject project but cannot order alternative, but he also thinks that PSC does not want responsibility to choose investments for utilities.
- Mike believes that PSC has authority to issue Order to standardize IRP process, models and inputs and practically utilities will likely obey, according to Mike, although PSC has no explicit authority to do this.
- Mike defended the DSM opt-out (opposed La Capra's recommendation to the Governor's office to remove opt-out) – industrials know best what works for them; and big industrials should not be subsidizing small industrials through DSM surcharge.
- In KY, they do interrupt customers on interruptible tariffs, but most industrials are not in favor of interruption – not worth it financially.
- Residential customers should have at least seasonal rates.
- Cogens are not popular because avoided costs are low (to his knowledge only one paper mill has a cogen) and because few industries with steam host possibilities; some concern from members about how avoided costs and buy back rates are determined.
- All else equal, his members prefer dealing with utilities than IPPs – some bad experience with IPPs recently – unreliable
- Mike mentioned that all cost of service studies that have been done to date show that residential customers are being subsidized. PSC has allowed it to continue due to gradualism, so this has institutionalized some cross-subsidization.
- De-coupling is a bad idea – can't trust utilities, how do we know the estimates are valid? Lower energy use could be a function of weather, economy, natural conservation, and not EE.
- Duke currently has a proposal pending in Indiana to get a return on investments not made.

8 December 7, 2007 11:30 AM

Participant: KY Attorney General's office (Dennis Howard, Paul ?, Larry Cook)

- They have intervened and will use an expert but have not yet selected one.
- KPSC statutory authority is limited according to AG – KPSC can only change DSM rates; other changes require legislative action.
- AG generally representing residential consumers, as KY is a poor state.
- AG supports EE but questions the means of getting there.
- DSM programs need to be cost-effective and AG is going to be stepping up and scrutinizing programs more in the future. Screening models should be standardized and consistently applied.
- They do no like decoupling (gave us a handout of resolution from NASUCA) – the fact that ratepayers pay more and utility shareholders are made whole is not palatable – they want utility shareholders to contribute to DSM; if decoupling

goes forward, AG suggests reducing ROE as risk is lower for utility under decoupling.
- PBR rates previously not successful in KY so probably won't be well received.
- Renewables – solar possible and AG is not opposed to more solar, methane capture starting up and biomass has potential.
- AG praised Duke's DSM evaluation process; deemed successful and Paul will be evaluating other DSMs.
- Quantification in DSM really important – AG wants to see validation of estimates of actual savings.
- Full cost accounting should monetize at least certain external costs. However, this must be quantified in a reasonable manner. Some costs may be qualitatively addressed.
- The consideration of "externalities" will require additional staffing at KPSC; AG offices.
- AG is OK with looking wider than cost savings in quantifying benefits but wants to make sure these can be monetized, avoid duplicating efforts with other agencies (EPA).
- Gradualism important -- even $2/month rate increase (anecdotally) makes an impact
- Low income assistance – AG wants shareholders to pay for this. Median 2000 household income in KY --$33,672.
- Home energy assistance programs are currently in utility rates.
- IRP should be more comprehensive; encourage utilities to work with one another; partner on projects. Changes in the process would require new statutory authority.
- According to AG, utility development of resources has been effective so far, IPPs have caused problems. IPPs are required to go through a siting approval process that does not require a showing of need.
- Carbon – don't know what the Federal government will do, utilities should have general plan, but concrete issues need to be dealt with after more facts are known.
- Large scale renewables currently not possible, but distributed renewables potential exists.

9 December 7, 2007 1:00 PM

Participant: Kentuckians for the Commonwealth (Burt Lauderdale, Jeff Young, Steve Voyce)

- May intervene but have not made a decision yet.
- Represent 5,000 state residents, fighting for "justice", primarily fighting on issues effecting low to moderate income residents.
- They provided a written statement and spent a while discussing their coal position:

- Coal is finite resource
- Easily mined coal exhausted
- Coal industry smaller in terms of economic impact – labor reductions; no great economic benefit has ever come about for local mining communities
- 80% of coal exported and not used in-state, so why continue subsidies?
- The coal subsidy is currently over $100 million.
- Negative externalities from coal – currently these are not acknowledged in market price
- Laws have been disobeyed and systematically disregarded and enforcement nil
- Coal is not clean but even if its 'mined' better, it will be destructive to environment
- Full cost accounting should take into account this destruction (but they offered no specifics on methods, inputs, assumptions)
- Carbon sequestration has major technical questions and commercial scale issues.

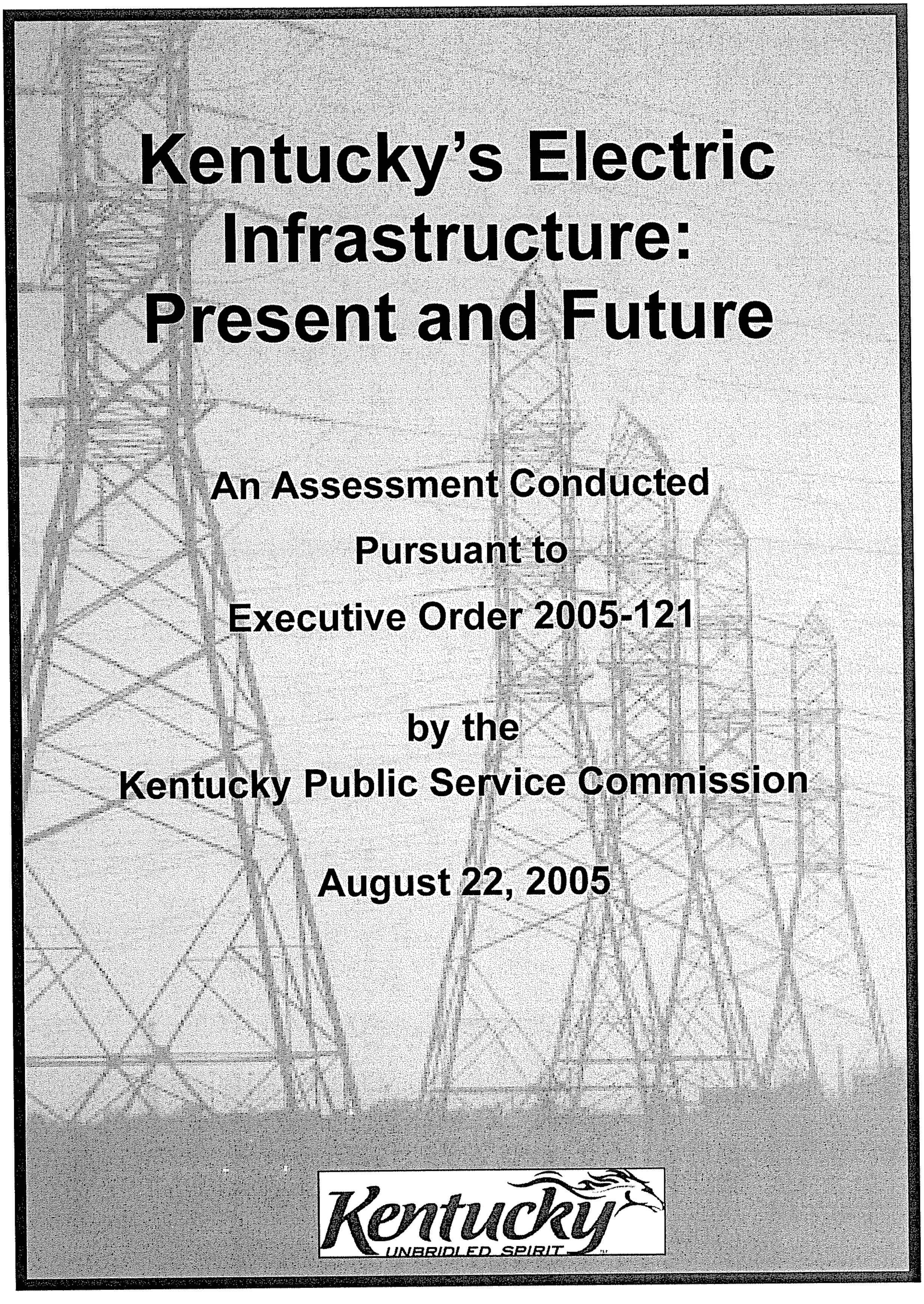
– They believe that it is time to begin a deliberate transition from coal to renewable energy alternatives. Funds should no longer be put into R&D for new coal technologies.
– DSM is more sustainable and can help low income – move coal subsidies to help low income.
– GHG have to be reduced, KFTC acknowledges challenges.
– Presumption that diversification comes with higher price tag needs to challenged – Jeff Young believes that there is no net cost to moving to more renewables and more EE – as proof, Steve described that KY's efficiency per capita is low – using more energy per capita, and residential bills are not as low as would be implied by costs of energy. So what is the issue? According to Steve, it's the poor housing stock – need for weatherization
– Funding should come from a clean energy fund or redistribution of coal industry subsidy. KFTC acknowledges that PSC cannot do this, but encouraged us to write into the report to attract the attention of legislature.
– Energy initiatives must take into consideration low-income effects; should look at percent of income plans as an option.
– Unhappy with current DSM – shifting peak rather than reducing total consumption should not be qualified as DSM according to KFTC, and there are hardly any DSM "industrial" programs. Need better definition of industrial customers who may opt out of DSM.
– KFTC is very critical of opt-out – Jeff believes it somehow the current state is unfair and proposes that large industrials pay for DSM through surcharge for small industrials. He does not view this as cross-subsidization, because he says the fact that large industrials take benefit of interruptible tariff.
– KFTC does not have any technical advice but wants to impart on the Commission the relative importance of these issues.

10 December 7, 2007 2:30 PM

Participant: Municipal Electric Power Association of Kentucky (Anette DuPont Ewing)

- Will intervene in administrative proceeding and hire consultant
- Wanted to make sure we understood that municipal utilities have different structures and different finances from investor-owned utilities regulated by the PSC.
- Only 3 munis generate, others are distribution entities. There are 29 Municipal providers, and 30 water and waste water companies.
- The Municipal EPA of Kentucky is the lowest cost provider in the lowest cost state.
- Her basic message – more EE can be achieved, she brought with her a handout of muni programs on EE done to date; she believes that munis have taken advantage of partnership opportunities better than IOUs, but also acknowledges that it is easier for munis to invest because they are closer to the consumers and because profits go directly to fund system improvements and DSM/EE is acknowledged to be one such improvement.
- There are a number of federal programs that are low-cost; low-effort programs.
- Munis would be interested in statewide IRP on voluntary basis.
- She believes that there is interest for greener power and consumers are willing to pay, if regulations are implemented by the General Assembly, and then passing it through to consumers (include munis who have long term contracts with IOUs to procure power).
- Transmission is an issue for munis and she believes its an issue then also for renewables.
- Renewables should be pursued through regional partnerships – TVA?
- In her opinion, the state will never have a lot of wind power, and solar is cost prohibitive currently, but opportunity for other renewables like hydro and nuclear unclear.

FN 34



Kentucky's Electric Infrastructure: Present and Future

An Assessment Conducted

Pursuant to

Executive Order 2005-121

by the

Kentucky Public Service Commission

August 22, 2005

Kentucky
UNBRIDLED SPIRIT

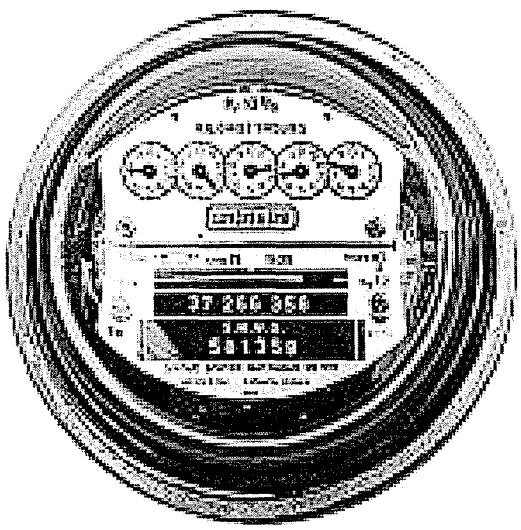
Externalities

The comments of the non-utility panel participants and members of the public participating at the technical conference heavily referenced externalities, which generally refer to external costs imposed without being accounted for in the cost of a product. The most significant of the externalities identified were emissions from coal-fired generating units. These are addressed in a separate Environmental Compliance section because environmental compliance is an issue that has an overriding impact on every resource acquisition decision of the electric utilities.

In this proceeding, the Commission heard from those who advocate including the full cost of externalities in the price of electricity. Neither the electric utilities nor other parties who might disagree have had the opportunity to comment or rebut the comments of those who advocate the inclusion of externalities in the price of electricity. The pros and cons should be considered and evaluated before any determination is made regarding externalities in relation to Kentucky's energy policy.

The costs of some externalities are already included in the price of electricity. The costs to comply with environmental emissions requirements are included in the utilities' generation resource acquisition decisions as well as in the evaluation made with regard to retrofitting existing generating units. In addition, most of the jurisdictional generators have implemented environmental compliance plans and environmental surcharges. The costs of land reclamation, compliance with regulations and other costs relating to coal production are included in the cost of coal. However, the potential exists that all related externalities are not fully included in the cost of coal since coal is a commodity and subject to competitive market pressures. To address the ideal proposed by some participants in this proceeding and include the full cost of externalities in the price of electricity would certainly increase the price of electricity or reduce utility revenues. There may be undesired or unintended consequences as a result.

The Commission believes that cautious consideration must be given to the inclusion of any externality in the price of electricity. The inclusion of externalities in the price of electricity implies that those that consume electricity are solely responsible for the existence of the externalities. Such implication may be inaccurate and thus result in an inappropriate transfer of costs. The Commission does not have jurisdiction under KRS Chapter 278 to explicitly allow for consideration of such externalities.



FN 36

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

A JOINT APPLICATION FOR THE APPROVAL OF DEMAND-SIDE MANAGEMENT PROGRAMS, A DSM COST RECOVERY MECHANISM, AND A CONTINUING COLLABORATIVE PROCESS ON DSM FOR LOUISVILLE GAS AND ELECTRIC COMPANY	)	CASE NO. 93-150

O R D E R

On April 21, 1993, Louisville Gas and Electric Company ("LG&E"), the Attorney General, Jefferson County, Metro Human Needs Alliance, People Organized and Working for Energy Reform, Anna Shed, Kentucky Industrial Utility Customers, Louisville Resources Conservation Council, and the Louisville and Jefferson County Community Action Agency (collectively, "Joint Applicants") tendered for filing a joint application for Commission approval of a document entitled Principles of Agreement ("Agreement") entered into by the Joint Applicants, and all other documents and tariffs necessary for the implementation of the Agreement.

The Agreement contains the basic structure and procedures for an experimental collaborative process to implement, monitor and administer demand-side management ("DSM") programs for LG&E's electric and natural gas customers. The Agreement also sets forth the guidelines under which LG&E would be allowed to recover administrative and program costs for DSM programs that have been approved by the collaborative process, revenues from sales lost due to implemented DSM programs, and a shareholder incentive. The Agreement further allows for an in-depth analysis and review of the operation of the Agreement by the Commission either in LG&E's next rate case or at the end of the three year experimental period, whichever comes first.

The Commission is impressed with the extraordinarily broad spectrum of individuals who entered into this Agreement. We are convinced that the Agreement is the product of many long and arduous hours of give and take, debate and probably strong argument, by a great number of people.

Throughout the course of its investigation into the merits of the Agreement, the Commission has developed misgivings and concerns about certain aspects of the Agreement. Although flaws exist now and others are likely to appear later, we are confident that the Agreement has built in sufficient flexibility to eliminate those flaws and address our concerns during and at the end of this three year experiment.

The Commission, being otherwise sufficiently advised, hereby finds that the joint application to implement on a three year experimental basis DSM programs, a cost recovery mechanism, and shareholder incentives should be approved. This decision is not intended to establish a precedent for LG&E or any other utility contemplating the implementation of DSM programs. The Commission remains committed to the principle that jurisdictional utility rates be at their lowest reasonable level consistent with the delivery of adequate and efficient service. To this end, we expect future DSM programs to be screened by cost/benefit tests.

IT IS THEREFORE ORDERED that:

1. The joint application, including the Principles of Agreement and related documents and tariffs, be and hereby are approved on a three year experimental basis.

2. Within 20 days from the date of this Order, LG&E shall file with the Commission its tariff sheets implementing the Principles of Agreement approved herein. The effective date of the tariffs shall be the date of this Order.

Done at Frankfort, Kentucky, this 12th day of November, 1993.

PUBLIC SERVICE COMMISSION

Chairman

Robert M. Davis

Vice Chairman

Commissioner

ATTEST:

Don Mills

Executive Director

FN 53

AN ACT relating to the advancement of energy policy, science, technology, and innovation in the Commonwealth, making an appropriation therefor, and declaring an emergency.

Be it enacted by the General Assembly of the Commonwealth of Kentucky:

SECTION 1. SUBCHAPTER 27 OF KRS CHAPTER 154 IS ESTABLISHED AND A NEW SECTION THEREOF IS CREATED TO READ AS FOLLOWS:

As used in this subchapter:

(1) "Activation date" means the date on which an approved company begins incurring recoverable costs or engaging in recoverable activity pursuant to the tax incentive agreement. The activation date shall be set forth in the tax incentive agreement and shall be a date within five (5) years of the date of final approval of the tax incentive agreement. The authority may extend the five (5) year period to no more than seven (7) years upon written application for an extension by the approved company. To implement the activation date, the approved company shall notify the authority of its intent to activate the tax incentives authorized in the tax incentive agreement. The activation date shall apply to all incentives included in the tax incentive agreement regardless of whether the approved company has met the requirements to receive all incentives at that time. If the approved company does not implement the activation date before the date established in the tax incentive agreement, the activation date shall be the date established in the tax incentive agreement;

(2) "Affiliate" has the same meaning as in KRS 154.22-010;

(3) (a) "Alternative fuel facility" means a facility located in Kentucky that is newly constructed on or after the effective date of this Act, or an existing facility located in Kentucky that is retrofitted or upgraded on or after the effective date of this Act, and that, after the new construction, retrofit, or upgrade primarily produces for sale alternative transportation fuels. For a retrofit of

(23) "Post-construction incentives" means the incentives available under Sections 6 and 8 of this Act;

(24) "Renewable energy facility" means a facility located in Kentucky that is newly constructed on or after the effective date of this Act, or an existing facility located in Kentucky that is retrofitted or upgraded after the effective date of this Act, and that, after the new construction, retrofit, or upgrade, utilizes:

(a) Wind power, biomass resources, landfill methane gas, hydropower, or other similar renewable resources to generate electricity in excess of one (1) megawatt for sale to unrelated entities; or

(b) Solar power to generate electricity in excess of fifty (50) kilowatts for sale to unrelated entities.

For a retrofit of an existing facility, the modification or addition shall primarily result in the production of electricity as described in paragraph (a) or (b) of this subsection;

(25) "Resident" shall have the same meaning as in KRS 141.010;

(26) "Retrofit" means a modification or addition to an existing facility that results in the production of a new and different product or uses a new or different process to produce the same product at the facility. Modifications or additions to a facility that maintain, restore, mend, or repair a facility shall not be considered a retrofit of the facility, and shall not be considered part of the capital investment if undertaken at the same time as a retrofit;

(27) "Synthetic natural gas" has the same meaning as in Section 38 of this Act;

(28) "Tax incentive agreement" means an agreement entered into in accordance with Section 4 of this Act;

(29) "Termination date" means a date established by the tax incentive agreement that is no more than twenty-five (25) years from the activation date; and

(30) "Upgrade" means an investment in an existing facility that results in an increase

FN 66

278.465 Definitions for KRS 278.465 to 278.468.

As used in KRS 278.465 to 278.468:

(1) "Eligible customer-generator" means a customer of a retail electric supplier who owns and operates an electric generating facility that is located on the customer's premises, for the primary purpose of supplying all or part of the customer's own electricity requirements.

(2) "Eligible electric generating facility" means an electric generating facility that:

 (a) Is connected in parallel with the electric distribution system;

 (b) Generates electricity using solar energy; and

 (c) Has a rated capacity of not greater than fifteen (15) kilowatts.

(3) "Kilowatt hour" means a measure of electricity defined as a unit of work of energy, measured as one (1) kilowatt of power expended for one (1) hour.

(4) "Net metering" means measuring the difference between the electricity supplied by the electric grid and the electricity generated by an eligible customer-generator that is fed back to the electric grid over a billing period.

Effective: July 13, 2004

History: Created 2004 Ky. Acts ch. 193, sec. 1, effective July 13, 2004.

FN 67

278.710 Granting or denial of construction certificate -- Policy of General Assembly -- Transfer of rights and obligation.

(1) Within ninety (90) days of receipt of an administratively complete application, or within one hundred twenty (120) days of receipt of an administratively complete application if a hearing is requested, the board shall, by majority vote, grant or deny a construction certificate, either in whole or in part, based upon the following criteria:

(a) Impact of the facility on scenic surroundings, property values, the pattern and type of development of adjacent property, and surrounding roads;

(b) Anticipated noise levels expected as a result of construction and operation of the proposed facility;

(c) The economic impact of the facility upon the affected region and the state;

(d) Whether the facility is proposed for a site upon which existing generating facilities, capable of generating ten megawatts (10MW) or more of electricity, are currently located;

(e) Whether the proposed facility will meet all local planning and zoning requirements that existed on the date the application was filed;

(f) Whether the additional load imposed upon the electricity transmission system by use of the merchant electric generating facility will adversely affect the reliability of service for retail customers of electric utilities regulated by the Public Service Commission;

(g) Except where the facility is subject to a statewide setback established by a planning and zoning commission as provided in KRS 278.704(3) and except for a facility proposed to be located on site of a former coal processing plant and the facility will use on-site waste coal as a fuel source, whether the exhaust stack of the proposed merchant electric generating facility is at least one thousand (1,000) feet from the property boundary of any adjoining property owner and two thousand (2,000) feet from any residential neighborhood, school, hospital, or nursing home facility. If a planning and zoning commission has established setback requirements that differ from those under KRS 278.704(2), the applicant shall provide evidence of compliance. If the facility is proposed to be located on site of a former coal processing plant and the facility will use on-site waste coal as a fuel source, the applicant shall provide evidence of compliance with the setback requirements provided in KRS 278.704(5);

(h) The efficacy of any proposed measures to mitigate adverse impacts that are identified pursuant to paragraph (a), (b), (e), or (f) of this subsection from the construction or operation of the proposed facility; and

(i) Whether the applicant has a good environmental compliance history.

(2) When considering an application for a construction certificate for a merchant electric generating facility, the board may consider the policy of the General Assembly to encourage the use of coal as a principal fuel for electricity generation as set forth in KRS 152.210, provided that any facility, regardless of fuel choice,

shall comply fully with KRS 224.10-280, 278.212, 278.216, and 278.700 to 278.716.

(3) A person that has received a construction certificate for a merchant electric generating facility shall not transfer rights and obligation under the certificate without having first applied for and received a board determination that:

(a) The acquirer has a good environmental compliance history; and

(b) The acquirer has the financial, technical, and managerial capacity to meet the obligations imposed by the terms of the approval or has the ability to contract to meet these obligations.

Effective: April 24, 2002

History: Created 2002 Ky. Acts ch. 365, sec. 6, effective April 24, 2002.

FN 68

AN ACT relating to the advancement of energy policy, science, technology, and innovation in the Commonwealth, making an appropriation therefor, and declaring an emergency.

Be it enacted by the General Assembly of the Commonwealth of Kentucky:

SECTION 1. SUBCHAPTER 27 OF KRS CHAPTER 154 IS ESTABLISHED AND A NEW SECTION THEREOF IS CREATED TO READ AS FOLLOWS:

As used in this subchapter:

(1) "Activation date" means the date on which an approved company begins incurring recoverable costs or engaging in recoverable activity pursuant to the tax incentive agreement. The activation date shall be set forth in the tax incentive agreement and shall be a date within five (5) years of the date of final approval of the tax incentive agreement. The authority may extend the five (5) year period to no more than seven (7) years upon written application for an extension by the approved company. To implement the activation date, the approved company shall notify the authority of its intent to activate the tax incentives authorized in the tax incentive agreement. The activation date shall apply to all incentives included in the tax incentive agreement regardless of whether the approved company has met the requirements to receive all incentives at that time. If the approved company does not implement the activation date before the date established in the tax incentive agreement, the activation date shall be the date established in the tax incentive agreement;

(2) "Affiliate" has the same meaning as in KRS 154.22-010;

(3) (a) "Alternative fuel facility" means a facility located in Kentucky that is newly constructed on or after the effective date of this Act, or an existing facility located in Kentucky that is retrofitted or upgraded on or after the effective date of this Act, and that, after the new construction, retrofit, or upgrade primarily produces for sale alternative transportation fuels. For a retrofit of

in the productivity of the facility. Increased productivity shall be measured in relation to the type of products that are required to be produced by that facility to be an eligible project.

SECTION 2. A NEW SECTION OF SUBCHAPTER 27 OF KRS CHAPTER 154 IS CREATED TO READ AS FOLLOWS:

(1) This subchapter shall be known as the "Incentives for Energy Independence Act."

(2) The General Assembly hereby finds and declares that it is in the best interest of the Commonwealth to induce the location of innovative energy-related businesses in the Commonwealth in order to advance the public purposes of achieving energy independence, creating new jobs and new investment, and creating new sources of tax revenues that but for the inducements to be offered by the authority to approved companies would not exist.

(3) The purpose of this subchapter is to assist the Commonwealth in moving to the forefront of national efforts to achieve energy independence by reducing the Commonwealth's reliance on imported energy resources. The provisions of this subchapter seek to accomplish this purpose by providing incentives for companies that, in a carbon capture ready manner, construct, retrofit, or upgrade facilities for the purpose of:

(a) Increasing the production and sale of alternative transportation fuels;

(b) Increasing the production and sale of synthetic natural gas, chemicals, chemical feedstocks, or liquid fuels, from coal, biomass resources, or waste coal through a gasification process; or

(c) Generating electricity for sale through alternative methods such as solar power, wind power, biomass resources, landfill methane gas, hydropower, or other similar renewable resources.

(4) To qualify for the incentives provided in this subchapter, the following

requirements shall be met:

(a) For an alternative fuel facility or gasification facility that uses coal as the primary feedstock the minimum capital investment shall be one hundred million dollars ($100,000,000);

(b) For an alternative fuel facility or gasification facility that uses biomass resources as the primary feedstock, the minimum capital investment shall be twenty-five million dollars ($25,000,000); and

(c) For a renewable energy facility, the minimum capital investment shall be one million dollars ($1,000,000).

(5) The incentives under the Incentives for Energy Independence Act are as follows:

(a) An advanced disbursement of post-construction incentives for which an approved company has been approved, the maximum amount of which is based upon the estimated labor component of the total capital investment of the eligible project, and the utilization of Kentucky residents during the construction period as set forth in Section 9 of this Act.

(b) Sales and use tax incentives of up to one hundred percent (100%) of the taxes paid on purchases of tangible personal property made to construct, retrofit, or upgrade an eligible project, as set forth in Sections 7 and 10 of this Act;

(c) Up to eighty percent (80%) of the severance taxes paid on the purchase or severance of coal that is subject to the tax imposed under KRS 143.020 and that is specifically used by an alternative fuel facility or a gasification facility as feedstock for an eligible project, as set forth in Sections 6 and 11 of this Act;

(d) Up to one hundred percent (100%) of the Kentucky income tax imposed under KRS 141.040 or 141.020, and the limited liability entity tax imposed under KRS 141.0401 on the income, Kentucky gross profits, or Kentucky

AN ACT relating to the advancement of energy policy, science, technology, and innovation in the Commonwealth, making an appropriation therefor, and declaring an emergency.

Be it enacted by the General Assembly of the Commonwealth of Kentucky:

SECTION 1. SUBCHAPTER 27 OF KRS CHAPTER 154 IS ESTABLISHED AND A NEW SECTION THEREOF IS CREATED TO READ AS FOLLOWS:

As used in this subchapter:

(1) "Activation date" means the date on which an approved company begins incurring recoverable costs or engaging in recoverable activity pursuant to the tax incentive agreement. The activation date shall be set forth in the tax incentive agreement and shall be a date within five (5) years of the date of final approval of the tax incentive agreement. The authority may extend the five (5) year period to no more than seven (7) years upon written application for an extension by the approved company. To implement the activation date, the approved company shall notify the authority of its intent to activate the tax incentives authorized in the tax incentive agreement. The activation date shall apply to all incentives included in the tax incentive agreement regardless of whether the approved company has met the requirements to receive all incentives at that time. If the approved company does not implement the activation date before the date established in the tax incentive agreement, the activation date shall be the date established in the tax incentive agreement;

(2) "Affiliate" has the same meaning as in KRS 154.22-010;

(3) (a) "Alternative fuel facility" means a facility located in Kentucky that is newly constructed on or after the effective date of this Act, or an existing facility located in Kentucky that is retrofitted or upgraded on or after the effective date of this Act, and that, after the new construction, retrofit, or upgrade primarily produces for sale alternative transportation fuels. For a retrofit of

an existing facility, the new modification or addition within the facility shall primarily produce alternative transportation fuel for sale.

(b) The alternative fuel facility may produce electricity as a by-product if the primary purpose for which the facility is constructed, retrofitted, or upgraded, and the primary function of the facility remains the production and sale of alternative transportation fuels;

(4) "Alternative transportation fuels" has the same meaning as in Section 38 of this Act;

(5) "Approved company" means a corporation, limited liability company, partnership, registered limited liability partnership, sole proprietorship, business trust, or any other entity approved for incentives for an eligible project;

(6) "Authority" means the Kentucky Economic Development Finance Authority established by KRS 154.20-010;

(7) "Base amount" means the tons of coal purchased and used or severed and used by the approved company as feedstock for an eligible project during the twelve (12) months prior to the month in which the approved company first begins receiving incentives under Sections 6 and 11 of this Act, that were subject to the tax imposed by KRS 143.020;

(8) "Biomass resources" has the same meaning as in Section 38 of this Act;

(9) (a) "Capital investment" means:

1. Obligations incurred for labor and to contractors, subcontractors, builders, and materialmen in connection with the acquisition, construction, installation, equipping, upgrading, or retrofitting of an eligible project;

2. The cost of acquiring land or rights in land and any cost incident thereto, including recording fees;

3. The cost of contract bonds and of insurance of all kinds that may be

Fd 73

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR AN ORDER DECLARING THE PENDLETON COUNTY LANDFILL GAS TO ENERGY PROJECT TO BE AN ORDINARY EXTENSION OF EXISTING SYSTEMS IN THE USUAL COURSE OF BUSINESS	)	CASE NO. 2006-00033

O R D E R

On January 23, 2006, East Kentucky Power Cooperative, Inc. ("East Kentucky Power" or "Applicant") filed an application requesting the Commission to declare that East Kentucky Power's Pendleton County Landfill Gas to Energy ("LFGTE") project is an ordinary extension of existing electric systems in the usual course of business and that a Certificate of Public Convenience and Necessity will not be required to construct the proposed facility. On three prior occasions, the Commission has granted similar declarations, finding that relatively small-sized LFGTE projects are exempt from the requirements for a Certificate of Public Convenience and Necessity under KRS 278.020(1).[1]

[1] Case No. 2002-00352, Application of East Kentucky Power Cooperative, Inc. For an Order Declaring Landfill Gas to Energy Projects to be Ordinary Extensions of Existing Systems in the Usual Course of Business (Order dated Dec. 18, 2002); Case No. 2002-00474, Application of East Kentucky Power Cooperative, Inc. For an Order Declaring the Green Valley and Laurel Ridge Landfill Gas to Energy Projects to be Ordinary Extensions of Existing Systems in the Usual Course of Business (Order dated Mar. 3, 2003); and Case No. 2005-00164, Application of East Kentucky Power Cooperative, Inc. For an Order Declaring the Hardin County Landfill Gas to Energy Projects to be Ordinary Extensions of Existing Systems in the Usual Course of Business (Order dated July 8, 2005).

Based on the application and the response to the data request, and being otherwise sufficiently advised, the Commission finds that the Pendleton County LFGTE project satisfies the criteria set forth in 807 KAR 5:001, Section 9(3), to be classified as an ordinary extension in the usual course of business. With an investment requirement of approximately $5 million, the cost to construct and operate the facility will not materially affect East Kentucky Power's financial condition or result in an increase in East Kentucky Power's wholesale power rates. In addition, the facility will not conflict with the existing certificates or service of other utilities under the Commission's jurisdiction. Therefore, the project will not create wasteful duplication of plant, equipment, property, or facilities.

IT IS THEREFORE ORDERED that the Pendleton County LFGTE project is properly classified as an ordinary extension of existing systems in the usual course of business and a Certificate of Public Convenience and Necessity, pursuant to KRS 278.020(1), is not required for its construction.

Done at Frankfort, Kentucky, this 10th day of March, 2006.

By the Commission

ATTEST:

Executive Director

FN 78

Kentucky Public Service Commission

Staff Report On the

2005 Integrated Resource Plan Report

of Louisville Gas and Electric Company

and Kentucky Utilities Company

Case No. 2005-00162

February 2006

SECTION 1

INTRODUCTION

Administrative Regulation 807 KAR 5:058, promulgated in 1990 by the Kentucky Public Service Commission, ("Commission") established an integrated resource planning ("IRP") process that provides for regular review by the Commission Staff of the long-range resource plans of the six major electric utilities under its jurisdiction. The goal of the Commission in establishing the IRP process was to ensure that all reasonable options for the future supply of electrity were being examined and pursued, and that ratepayers were being provided a reliable supply of electricity at the lowest possible cost.

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (jointly "LG&E/KU") submitted their 2005 Joint IRP to the Commission on April 21, 2005. The IRP submitted by LG&E/KU includes the plan for meeting their customers' electricity requirements for the period 2005-2019.

LG&E and KU are investor-owned public utilities that supply electricity and natural gas to customers primarily located in Kentucky. Both are subsidiaries of E.ON US, formerly LG&E Energy LLC. As owners and operators of interconnected electric generation, transmission, and distribution facilities, LG&E/KU achieve economic benefits through the operation of an interconnected and centrally dispatched system and through coordinated planning, construction, operation and maintenance of their facilities.

LG&E and KU are members of the Midwest Independent System Operator ("MISO") a regional transmission organization subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Since the issuance of the Staff Report on LG&E's and KU's Joint 2002 IRP, LG&E and KU have announced their intention to terminate their membership in MISO. LG&E/KU's request to exit MISO is presently pending in cases before both the Commission and FERC.

LG&E supplies electricity and natural gas to customers in the Louisville, Kentucky greater metropolitan area. It provides electric service to more nearly 400,000 customers in Louisville and 11 surrounding counties with a total service area covering approximately 700 square miles.

KU supplies retail electricity in 77 Kentucky counties to over 515,000 customers in a service area covering roughly 6,500 non-contiguous square miles and in 5 Virginia counties. It sells wholesale electricity to 12 Kentucky municipalities and the municipal system serving Pitcairn, Pennsylvania.

The purpose of this report is to review and evaluate the Joint IRP in accordance with the requirements of 807 KAR 5:058, Section 12(3), which requires the Commission

Staff to issue a report summarizing its review of each IRP filing made with the Commission and make suggestions and recommendations to be considered in future IRP filings. The Staff recognizes that resource planning is a dynamic ongoing process. Thus, this review is designed to offer suggestions and recommendations to LG&E/KU on how to improve their resource plan in the future. Specifically, the Staff's goals are to ensure that:

- All resource options are adequately and fairly evaluated;
- Critical data, assumptions and methodologies for all aspects of the plan are adequately documented and are reasonable; and
- The selected plan represents the leas-cost, least risk plan for the ultimate customers served by LG&E/KU, recognizing the need to achieve a balance between the interests of ratepayers and shareholders.

The report also includes an incremental component, noting any significant changes from the Companies' most recent IRP filed in 2002.

Based on a forecasted average annual growth rate of 2.0% over the 2005-2019 forecast period, LG&E/KU will require resource additions of roughly 2,400 megawatts ("MW"). Supply-side resources included in the plan include a supercritical 732 MW (the LG&E/KU share would be 549 MW) coal-fired base load plant to be located at LG&E's Trimble County Generating Station and 6 "greenfield" combustion turbines ("CTs") with a total capacity of 888 MW. The resources also include 28 MW through greater demand-side management ("DSM") savings, a hydro power purchase agreement with an average summer capacity of 181 MW, and a 750 MW supercritical coal unit for which a site was not designated.

The remainder of this report is organized as follows:

- Section 2, Load Forecasting, reviews LG&E/KU's projected load growth and load forecasting methodology.

- Section 3, Demand-Side Management, summarizes LG&E/KU's evaluation of DSM opportunities.

- Section 4, Supply-Side Resource Assessment, focuses on supply resources available to meet LG&E/KU's load requirements.

- Section 5, Integration and Plan Optimization, discusses LG&E/KU's overall assessment of supply-side and demand-side options and their integration into an overall resource plan.

FN 79

Kentucky Public Service Commission

Staff Report On the

2003 Integrated Resource Plan Report

of East Kentucky Power Cooopertive

Case No. 2003-00051

September 2004

KDOE recommends that, after completing these three recommendations, East Kentucky conduct an integrated analysis to determine whether or not additional centralized power plants will still be needed in the foreseeable future.

KDOE also recommends that East Kentucky develop and propose a net metering tariff to accommodate customers that want to install small-scale, environmentally benign generating technologies to reduce their electric bills.

Discussion of Reasonableness

In its report on East Kentucky's 2000 IRP, Staff made several recommendations concerning DSM that were used by East Kentucky as a foundation for the analysis of DSM activities in its 2003 IRP. Staff's recommendations included:

- East Kentucky should perform a new DSM study prior to its next IRP filing. The IRP should include thorough discussion of the study and documentation relative to the consideration and screening of new DSM programs, applications, and technologies.

- East Kentucky should meet with the Kentucky Department of Energy (KDOE) and the Attorney General (AG), if the AG so desires, well in advance of the next IRP filing to discuss the DSM concerns of the parties and discuss the results of the dialogue and how it incorporated the parties' concerns in the next IRP analysis.

- East Kentucky should report on efforts to evaluate and support local integrated resource planning, cogeneration and distributed generation, and other initiatives of the type advocated by KDOE.

- East Kentucky, in its next IRP, should discuss in detail how it factors environmental compliance costs such as for NO_X and CO_2 into its DSM program evaluation.

In response to the recommendation that it perform a new DSM study, East Kentucky submitted its DSManager based study, which was discussed earlier. While its study is not as comprehensive as the DSM studies submitted by some Kentucky jurisdictional utilities, Staff views East Kentucky's DSM study as a reasonable effort in beginning to consider and screen new DSM programs, applications, and technologies.

It is unclear to Staff as to whether its recommendation that East Kentucky meet with KDOE and the AG to discuss the DSM concerns of the parties was acted upon. It is also unclear whether the results of such dialogue or how East Kentucky addressed the parties' concerns were reflected in this 2003 IRP.

East Kentucky's IRP does not reflect that it responded to Staff's recommendation that it report on its efforts to evaluate and support local integrated resource planning, cogeneration and distributed generation and other initiatives of the type advocated by KDOE. Staff repeats this recommendation for East Kentucky's next IRP.

Figure 6-1

KENTUCKY POWER COMPANY

INTEGRATED RESOURCE PLANNING REPORT
TO THE
KENTUCKY PUBLIC SERVICE COMMISSION

Submitted Pursuant to
Commission Regulation 807 KAR 5:058

Case No. 2002-00377
November 15, 2002

In the Matter of:

The 2005 Joint Integrated Resource Plan of	)
Louisville Gas and Electric Company and	) Case No.
Kentucky Utilities Company	) 2005-00162

VOLUME I – REDACTED
INTEGRATED RESOURCE PLAN

FILED: April 21, 2005

2004-00014

CINERGY®

The Union Light, Heat & Power Company

RECEIVED

APR 0 2 2004

PUBLIC SERVICE
COMMISSION

2003

INTEGRATED RESOURCE PLAN

VOLUME I

April 1, 2004

By: The Union Light, Heat and Power Company.
Gregory C. Ficke, President
139 East Fourth Street
Cincinnati, OH 45202

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PUBLIC SERVICE COMMISSION

Big Rivers Electric Corporation

Touchstone Energy

Case 2002-00428

2002 Integrated Resource Plan

Prepared for

Big Rivers Electric Corporation

Henderson, Kentucky

November 2002

GDS Associates, Inc.

EAST KENTUCKY POWER COOPERATIVE

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COMMISSION

Integrated Resource Plan

Case No. 2006-~~00017~~ 00471

REDACTED

October 21, 2006

A Touchstone Energy Cooperative

FN 1

Table A1. Selected Electric Industry Summary Statistics by State, 2005 (Continued)

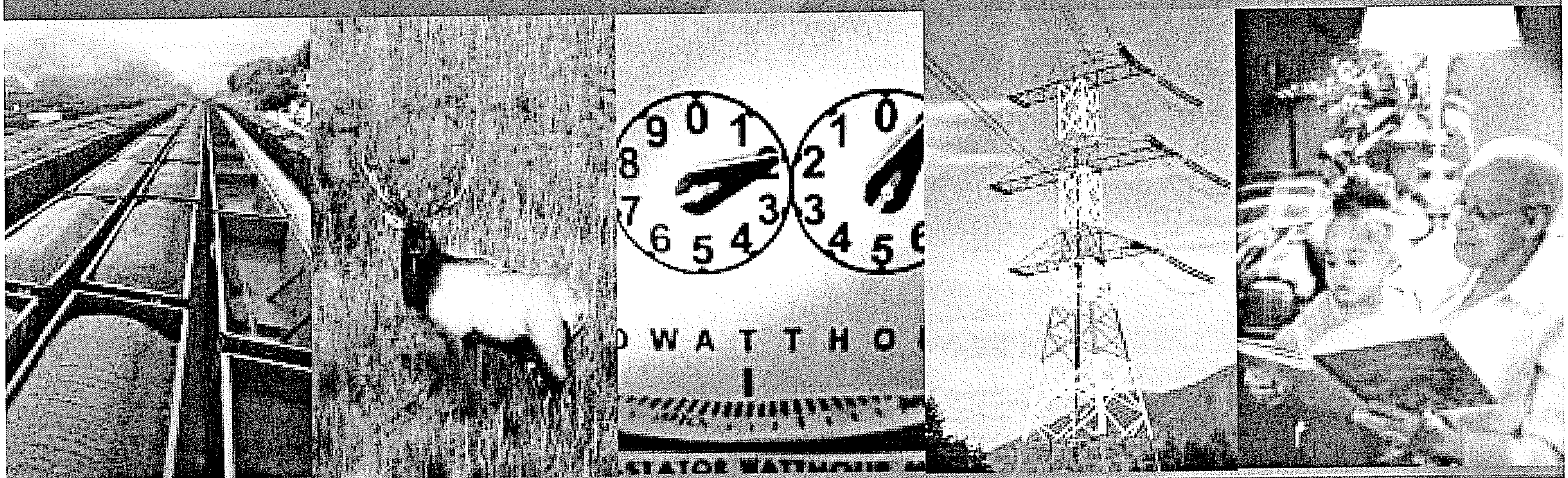
State	Total Retail Sales		Full Service Sales (including unregulated generators)		Other Providers		Direct Use		Average Retail Price, All Sectors	
	(MWh)	Rank	(MWh)	Rank	(MWh)	Rank	(MWh)	Rank	(cents/kWh)	Rank
Alabama	89,201,620	15	89,201,620	15	-	-	4,284,503	7	6.46	38
Alaska	5,912,571	50	5,912,571	48	-	-	329,542	37	11.72	7
Arizona	69,390,686	22	69,390,686	21	-	-	501,869	34	7.79	19
Arkansas	46,164,923	29	46,164,923	27	-	-	2,066,336	17	6.30	41
California	254,249,507	2	230,843,182	2	23,406,325	4	11,009,718	3	11.63	8
Colorado	48,353,236	27	48,353,236	26	-	-	80,608	44	7.64	21
Connecticut	33,095,029	33	32,354,549	33	740,480	17	225,040	39	12.06	5
Delaware	12,136,788	43	11,187,095	41	949,693	15	695,737	29	7.76	20
District of Columbia	11,816,207	44	4,802,919	50	7,013,288	11	-	-	9.18	12
Florida	224,977,011	3	224,977,011	3	-	-	4,978,723	6	8.76	15
Georgia	132,265,452	8	132,265,452	6	-	-	5,203,118	5	7.43	25
Hawaii	10,538,910	47	10,538,910	45	-	-	380,025	36	18.33	1
Idaho	21,852,681	38	21,852,681	38	-	-	550,252	32	5.12	50
Illinois	144,986,215	7	117,048,497	8	27,937,718	2	3,555,809	10	6.95	29
Indiana	106,548,910	12	106,548,910	10	-	-	7,344,408	4	5.88	45
Iowa	42,756,808	31	42,756,808	30	-	-	1,305,629	22	6.69	33
Kansas	39,024,283	32	39,024,283	32	-	-	5,389	49	6.55	37
Kentucky	89,351,466	14	89,351,466	14	-	-	389,447	35	5.01	51
Louisiana	77,389,170	20	77,389,170	19	-	-	19,845,343	2	8.03	18
Maine	12,362,879	42	369,594	51	11,993,285	8	3,324,756	11	10.57	11
Maryland	68,365,385	23	49,163,275	25	19,202,110	5	1,094,648	27	8.13	17
Massachusetts	57,227,588	25	41,373,621	31	15,853,967	7	1,160,995	26	12.18	4
Michigan	110,444,563	10	99,110,699	12	11,333,864	9	2,477,902	16	7.23	26
Minnesota	66,019,053	24	66,019,053	22	-	-	1,185,448	25	6.61	35
Mississippi	45,901,064	30	45,901,064	28	-	-	1,349,941	21	7.54	22
Missouri	80,940,494	19	80,940,494	18	-	-	142,644	42	6.13	42
Montana	13,478,838	41	10,642,433	44	2,836,405	12	93,256	43	6.72	32
Nebraska	26,975,944	36	26,975,944	36	-	-	75,065	46	5.87	46
Nevada	32,500,630	34	32,325,814	34	174,816	18	587,269	30	9.02	14
New Hampshire	11,244,628	45	11,121,954	42	122,674	19	216,095	40	12.53	3
New Jersey	81,896,813	17	65,343,404	23	16,553,409	6	2,621,051	15	10.89	10
New Mexico	20,638,951	39	20,638,951	39	-	-	77,971	45	7.51	23
New York	150,147,571	5	93,474,451	13	56,673,120	1	3,806,503	9	13.95	2
North Carolina	128,335,377	9	128,335,377	7	-	-	2,985,075	13	7.19	27
North Dakota	10,839,990	46	10,839,990	43	-	-	211,673	41	5.92	44
Ohio	160,176,303	4	133,460,651	5	26,715,652	3	1,281,665	23	7.08	28
Oklahoma	53,707,102	26	53,707,102	24	-	-	503,553	33	6.85	30
Oregon	46,419,245	28	44,864,641	29	1,554,604	14	1,190,391	24	6.34	39
Pennsylvania	148,272,940	6	137,220,957	4	11,051,983	10	3,268,349	12	8.27	16
Rhode Island	8,049,112	49	7,160,386	47	888,726	16	69,478	47	11.97	6
South Carolina	81,254,088	18	81,254,088	17	-	-	1,598,662	19	6.72	31
South Dakota	9,811,017	48	9,811,017	46	-	-	-	-	6.60	36
Tennessee	103,905,421	13	103,905,421	11	-	-	1,939,498	18	6.31	40
Texas	334,258,262	1	334,258,262	1	-	-	50,804,561	1	9.14	13
Utah	25,000,498	37	25,000,498	37	-	-	751,289	28	5.92	43
Vermont	5,883,053	51	5,883,053	49	-	-	30,484	48	10.95	9
Virginia	108,849,552	11	108,827,497	9	22,055	20	2,722,582	14	6.64	34
Washington	83,425,200	16	81,394,743	16	2,030,457	13	573,987	31	5.87	47
West Virginia	30,152,069	35	30,152,069	35	-	-	1,364,199	20	5.15	49
Wisconsin	70,335,683	21	70,335,683	20	-	-	4,119,332	8	7.48	24
Wyoming	14,137,727	40	14,137,727	40	-	-	320,549	38	5.16	48
United States	3,660,968,513	-	3,423,913,882	-	237,054,631	-	154,700,367	-	8.14	-

Table A1. Selected Electric Industry Summary Statistics by State, 2006 (Continued)

State	Total Retail Sales		Full Service Sales (including unregulated generators)		Other Providers		Direct Use		Average Retail Price, All Sectors	
	(MWh)	Rank	(MWh)	Rank	(MWh)	Rank	(MWh)	Rank	(cents/kWh)	Rank
Alabama	90,677,695	14	90,677,695	13	-	-	6,209,972	5	7.07	30
Alaska	6,182,291	50	6,182,291	48	-	-	289,065	38	12.84	7
Arizona	73,252,776	21	73,252,776	20	-	-	268,615	39	8.24	21
Arkansas	46,635,624	30	46,635,624	28	-	-	2,054,330	17	6.99	33
California	262,958,528	2	241,735,246	2	21,223,282	4	14,030,060	3	12.82	8
Colorado	49,733,698	27	49,733,698	25	-	-	150,126	42	7.61	26
Connecticut	31,677,453	35	30,148,657	35	1,528,796	15	302,207	37	14.83	4
Delaware	11,554,672	43	9,043,983	46	2,510,689	13	493,536	34	10.13	15
District of Columbia	11,396,424	44	5,964,971	49	5,431,453	11	0	50	11.08	12
Florida	228,219,544	3	228,219,544	3	-	-	5,274,184	7	10.45	13
Georgia	134,834,168	8	134,834,168	6	-	-	5,421,307	6	7.63	25
Hawaii	10,567,912	47	10,567,912	43	-	-	365,273	36	20.72	1
Idaho	22,761,749	38	22,761,749	38	-	-	604,855	33	4.92	51
Illinois	142,447,811	6	115,937,725	8	26,510,086	2	3,606,139	9	7.07	31
Indiana	105,664,484	12	105,664,484	10	-	-	7,524,962	4	6.46	42
Iowa	43,336,835	31	43,336,835	29	-	-	1,595,367	22	7.01	32
Kansas	39,751,302	32	39,751,302	31	-	-	7,386	49	6.89	38
Kentucky	88,743,435	15	88,743,435	14	-	-	399,822	35	5.43	48
Louisiana	77,467,748	20	77,467,748	19	-	-	23,505,570	2	8.30	20
Maine	12,284,768	42	831,667	51	11,453,101	8	4,344,309	8	11.80	10
Maryland	63,173,143	24	41,666,356	30	21,506,787	3	1,323,256	25	9.95	16
Massachusetts	55,850,090	25	34,794,615	32	21,055,475	5	911,950	30	15.45	2
Michigan	108,017,697	10	102,398,636	12	5,619,061	10	2,353,796	14	8.14	22
Minnesota	66,769,931	23	66,769,931	22	-	-	1,666,353	20	6.98	35
Mississippi	46,936,437	29	46,936,437	27	-	-	1,963,919	18	8.33	19
Missouri	82,015,230	17	82,015,230	17	-	-	160,160	41	6.30	43
Montana	13,814,980	41	10,820,511	42	2,994,469	12	120,358	44	6.91	37
Nebraska	27,276,292	36	27,276,292	36	-	-	72,863	46	6.07	46
Nevada	34,586,260	33	33,329,949	33	1,256,311	16	893,050	31	9.63	17
New Hampshire	11,094,343	46	10,048,822	45	1,045,521	18	124,832	43	13.84	6
New Jersey	79,680,947	19	64,113,031	23	15,567,916	6	2,209,981	16	11.88	9
New Mexico	21,434,957	39	21,434,957	39	-	-	92,839	45	7.37	28
New York	142,238,019	7	87,101,911	15	55,136,108	1	1,717,878	19	15.27	3
North Carolina	126,698,979	9	126,698,979	7	-	-	2,350,399	15	7.53	27
North Dakota	11,245,238	45	11,245,238	41	-	-	195,339	40	6.21	44
Ohio	153,428,844	4	140,258,856	4	13,169,988	7	1,296,078	26	7.71	24
Oklahoma	54,905,314	26	54,905,314	24	-	-	986,758	28	7.30	29
Oregon	48,069,265	28	46,962,026	26	1,107,239	17	1,418,985	23	6.53	41
Pennsylvania	146,150,358	5	137,244,377	5	8,905,981	9	2,872,473	11	8.68	18
Rhode Island	7,799,126	49	6,770,572	47	1,028,554	19	66,119	47	13.98	5
South Carolina	80,877,321	18	80,877,321	18	-	-	1,619,838	21	6.98	34
South Dakota	10,056,387	48	10,056,387	44	-	-	0	50	6.70	40
Tennessee	103,931,744	13	103,931,744	11	-	-	2,376,179	13	6.97	36
Texas	342,724,213	1	342,724,213	1	-	-	33,121,582	1	10.34	14
Utah	26,365,716	37	26,365,716	37	-	-	967,261	29	5.99	47
Vermont	5,795,029	51	5,795,029	50	-	-	25,524	48	11.37	11
Virginia	106,721,241	11	106,679,301	9	41,940	20	2,618,130	12	6.86	39
Washington	85,033,335	16	82,941,354	16	2,091,981	14	759,485	32	6.14	45
West Virginia	32,312,126	34	32,312,126	34	-	-	1,390,780	24	5.04	50
Wisconsin	69,820,749	22	69,820,749	21	-	-	3,586,727	10	8.13	23
Wyoming	14,946,612	40	14,946,612	40	-	-	1,216,635	27	5.27	49
United States	3,669,918,840	-	3,450,734,102	-	219,184,738	-	146,926,612	-	8.90	-

FN 2

KENTUCKY'S ENERGY OPPORTUNITIES FOR OUR FUTURE



A COMPREHENSIVE ENERGY STRATEGY

Kentucky
UNBRIDLED SPIRIT

GOVERNOR ERNIE FLETCHER

The Need for a Comprehensive Energy Strategy

Kentucky is a land blessed with abundant natural resources, industrious people and great natural beauty. Our challenge today is to continue to grow our economy, utilize our resources in a sustainable manner and protect and maintain our commitment to environmental quality. To accomplish these objectives, Kentucky must have a comprehensive state energy plan.

Kentucky historically has relied primarily on coal to produce its electricity, and likely will do so in the future. Simply stated, without an adequate supply of coal, Kentuckians will not continue to enjoy the benefits of low-cost electricity rates. Nonetheless, we have opportunities to diversify our energy portfolio to help our citizens save money and protect the environment.

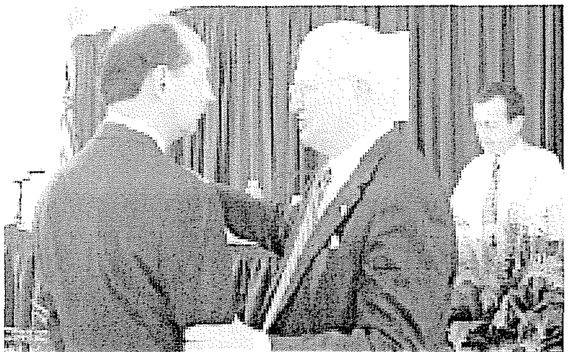
Recent trends also reveal opportunities to strengthen Kentucky's energy position. Although Kentucky enjoys the lowest electricity rates in the nation, we rank 23rd in residential energy consumption and are the seventh highest per capita primary energy-consuming state. The average monthly industrial electric bill in Kentucky is 123% higher than the national average. This indicates that our low electricity rates do not translate into low energy bills if we consume more energy than necessary in our homes and businesses.

Energy production and usage also affect the state's environment. Energy consumption, including the energy we use to light and heat our homes, contributes to carbon dioxide, sulfur dioxide, nitrogen and mercury emissions. Technological advances—such as clean coal technology, alternative fuels, hybrid vehicles and hydrogen fuel cells—offer great promise to enhance environmental quality. State government can and should play a role in promoting cleaner fuels, but Kentuckians must also realize that individual choices are vital to a cleaner environmental future.

Kentucky's energy sector is currently well positioned but that position is not guaranteed. The Legislative Research Commission's Interim Special Subcommittee on Energy realized in 2003 that Kentucky must formulate a statewide energy policy. A resolution passed by the subcommittee recognized the "tremendous challenges and tremendous opportunities in the energy arena."

The resolution encouraged the incoming administration "to craft state policy and insure that developments in the energy field take place in a planned and thoughtful fashion." Governor Fletcher is committed to work with the legislature to develop and implement a comprehensive energy policy for the benefit of all Kentuckians.

During the announcement of the Commonwealth Energy Policy Task Force, Governor Fletcher stated, "I am optimistic that by including the co-chairs of the Legislative Research Commission (LRC) Special Subcommittee on Energy, we can build the necessary bi-partisan support on energy issues to move this state forward."



Commerce Secretary Jim Host, right and House Majority Floor Leader Rocky Adkins.

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AN ACT relating to the advancement of energy policy, science, technology, and innovation in the Commonwealth, making an appropriation therefor, and declaring an emergency.

Be it enacted by the General Assembly of the Commonwealth of Kentucky:

SECTION 1. SUBCHAPTER 27 OF KRS CHAPTER 154 IS ESTABLISHED AND A NEW SECTION THEREOF IS CREATED TO READ AS FOLLOWS:

As used in this subchapter:

(1) "Activation date" means the date on which an approved company begins incurring recoverable costs or engaging in recoverable activity pursuant to the tax incentive agreement. The activation date shall be set forth in the tax incentive agreement and shall be a date within five (5) years of the date of final approval of the tax incentive agreement. The authority may extend the five (5) year period to no more than seven (7) years upon written application for an extension by the approved company. To implement the activation date, the approved company shall notify the authority of its intent to activate the tax incentives authorized in the tax incentive agreement. The activation date shall apply to all incentives included in the tax incentive agreement regardless of whether the approved company has met the requirements to receive all incentives at that time. If the approved company does not implement the activation date before the date established in the tax incentive agreement, the activation date shall be the date established in the tax incentive agreement;

(2) "Affiliate" has the same meaning as in KRS 154.22-010;

(3) (a) "Alternative fuel facility" means a facility located in Kentucky that is newly constructed on or after the effective date of this Act, or an existing facility located in Kentucky that is retrofitted or upgraded on or after the effective date of this Act, and that, after the new construction, retrofit, or upgrade primarily produces for sale alternative transportation fuels. For a retrofit of

in the productivity of the facility. Increased productivity shall be measured in relation to the type of products that are required to be produced by that facility to be an eligible project.

SECTION 2. A NEW SECTION OF SUBCHAPTER 27 OF KRS CHAPTER 154 IS CREATED TO READ AS FOLLOWS:

(1) This subchapter shall be known as the "Incentives for Energy Independence Act."

(2) The General Assembly hereby finds and declares that it is in the best interest of the Commonwealth to induce the location of innovative energy-related businesses in the Commonwealth in order to advance the public purposes of achieving energy independence, creating new jobs and new investment, and creating new sources of tax revenues that but for the inducements to be offered by the authority to approved companies would not exist.

(3) The purpose of this subchapter is to assist the Commonwealth in moving to the forefront of national efforts to achieve energy independence by reducing the Commonwealth's reliance on imported energy resources. The provisions of this subchapter seek to accomplish this purpose by providing incentives for companies that, in a carbon capture ready manner, construct, retrofit, or upgrade facilities for the purpose of:

(a) Increasing the production and sale of alternative transportation fuels;

(b) Increasing the production and sale of synthetic natural gas, chemicals, chemical feedstocks, or liquid fuels, from coal, biomass resources, or waste coal through a gasification process; or

(c) Generating electricity for sale through alternative methods such as solar power, wind power, biomass resources, landfill methane gas, hydropower, or other similar renewable resources.

(4) To qualify for the incentives provided in this subchapter, the following

FN 4

AN ACT relating to the advancement of energy policy, science, technology, and innovation in the Commonwealth, making an appropriation therefor, and declaring an emergency.

Be it enacted by the General Assembly of the Commonwealth of Kentucky:

SECTION 1. SUBCHAPTER 27 OF KRS CHAPTER 154 IS ESTABLISHED AND A NEW SECTION THEREOF IS CREATED TO READ AS FOLLOWS:

As used in this subchapter:

(1) "Activation date" means the date on which an approved company begins incurring recoverable costs or engaging in recoverable activity pursuant to the tax incentive agreement. The activation date shall be set forth in the tax incentive agreement and shall be a date within five (5) years of the date of final approval of the tax incentive agreement. The authority may extend the five (5) year period to no more than seven (7) years upon written application for an extension by the approved company. To implement the activation date, the approved company shall notify the authority of its intent to activate the tax incentives authorized in the tax incentive agreement. The activation date shall apply to all incentives included in the tax incentive agreement regardless of whether the approved company has met the requirements to receive all incentives at that time. If the approved company does not implement the activation date before the date established in the tax incentive agreement, the activation date shall be the date established in the tax incentive agreement;

(2) "Affiliate" has the same meaning as in KRS 154.22-010;

(3) (a) "Alternative fuel facility" means a facility located in Kentucky that is newly constructed on or after the effective date of this Act, or an existing facility located in Kentucky that is retrofitted or upgraded on or after the effective date of this Act, and that, after the new construction, retrofit, or upgrade primarily produces for sale alternative transportation fuels. For a retrofit of

requirements shall be met:

(a) For an alternative fuel facility or gasification facility that uses coal as the primary feedstock the minimum capital investment shall be one hundred million dollars ($100,000,000);

(b) For an alternative fuel facility or gasification facility that uses biomass resources as the primary feedstock, the minimum capital investment shall be twenty-five million dollars ($25,000,000); and

(c) For a renewable energy facility, the minimum capital investment shall be one million dollars ($1,000,000).

(5) The incentives under the Incentives for Energy Independence Act are as follows:

(a) An advanced disbursement of post-construction incentives for which an approved company has been approved, the maximum amount of which is based upon the estimated labor component of the total capital investment of the eligible project, and the utilization of Kentucky residents during the construction period as set forth in Section 9 of this Act.

(b) Sales and use tax incentives of up to one hundred percent (100%) of the taxes paid on purchases of tangible personal property made to construct, retrofit, or upgrade an eligible project, as set forth in Sections 7 and 10 of this Act;

(c) Up to eighty percent (80%) of the severance taxes paid on the purchase or severance of coal that is subject to the tax imposed under KRS 143.020 and that is specifically used by an alternative fuel facility or a gasification facility as feedstock for an eligible project, as set forth in Sections 6 and 11 of this Act;

(d) Up to one hundred percent (100%) of the Kentucky income tax imposed under KRS 141.040 or 141.020, and the limited liability entity tax imposed under KRS 141.0401 on the income, Kentucky gross profits, or Kentucky

gross receipts of the approved company generated by or arising from the eligible project, as set forth in Sections 8 and 12 of this Act; and

(e) Authorization for the approved company to impose a wage assessment of up to four percent (4%) of the gross wages of each employee subject to the Kentucky income tax:

1. Whose job was created as a result of the eligible project;

2. Who is employed by the approved company to work at the facility; and

3. Who is on the payroll of the approved company or an affiliate of the approved company;

as set forth in Section 8 of this Act.

(6) The maximum recovery from all incentives approved under this subchapter for an eligible project shall not exceed fifty percent (50%) of the capital investment in the eligible project.

(7) The incentives available to an approved company shall be negotiated with and approved by the authority.

(8) If a newly constructed facility that qualifies for incentives under this subchapter is later upgraded or retrofitted in a manner that would qualify for incentives under this subchapter, the retrofit or upgrade shall be a separate eligible project, and the minimum investment requirements and carbon capture readiness requirements if required, shall be met for the retrofit or upgrade to qualify for incentives under this subchapter.

(9) The General Assembly finds that the authorities granted by this subchapter are proper governmental and public purposes for which public moneys may be expended.

SECTION 3. A NEW SECTION OF SUBCHAPTER 27 OF KRS CHAPTER 154 IS CREATED TO READ AS FOLLOWS:

(1) A company with an eligible project may submit an application for incentives to

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Table 1. 2006 Summary Statistics

Item	Value	U.S. Rank
Kentucky		
NERC Region(s)		RFC/SERC
Primary Energy Source		Coal
Net Summer Capacity (megawatts)	20,047	21
Electric Utilities	16,878	16
Independent Power Producers & Combined Heat and Power	3,169	29
Net Generation (megawatthours)	98,792,014	16
Electric Utilities	86,816,479	14
Independent Power Producers & Combined Heat and Power	11,975,535	25
Emissions (thousand metric tons)		
Sulfur Dioxide	391	9
Nitrogen Oxide	158	6
Carbon Dioxide	93,160	7
Sulfur Dioxide (lbs/MWh)	8.7	8
Nitrogen Oxide (lbs/MWh)	3.5	12
Carbon Dioxide (lbs/MWh)	2,079	4
Total Retail Sales (megawatthours)	88,743,435	15
Full Service Provider Sales (megawatthours)	88,743,435	14
Direct Use (megawatthours)	399,822	35
Average Retail Price (cents/kWh)	5.43	48

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capacity, 2006

Plant	Primary Energy Source or Technology	Operating Company	Net Summer Capacity (MW)
Kentucky			
1. Paradise	Coal	Tennessee Valley Authority	2,175
2. Ghent	Coal	Kentucky Utilities Co	1,945
3. E W Brown	Coal	Kentucky Utilities Co	1,546
4. Mill Creek	Coal	Louisville Gas & Electric Co	1,472
5. Trimble County	Coal	Louisville Gas & Electric Co	1,471
6. Shawnee	Coal	Tennessee Valley Authority	1,329
7. H L Spurlock	Coal	East Kentucky Power Coop, Inc	1,118
8. Big Sandy	Coal	Kentucky Power Co	1,060
9. Riverside Generating LLC	Gas	Riverside Generating Co LLC	825
10. J K Smith	Gas	East Kentucky Power Coop, Inc	626

See footnotes at end of tables.

Figure 1-1

Table 3. Top Five Retailers of Electricity, with End Use Sectors, 2006
(Megawatthours)

Entity	Type of Provider	All Sectors	Residential	Commercial	Industrial	Transportation
Kentucky						
1. Kentucky Utilities Co	Investor-Owned	17,786,364 20%	5,907,821	5,795,584	6,082,959	-
2. Tennessee Valley Authority	Federal	14,674,996 17%	-	-	14,674,996	-
3. Louisville Gas & Electric Co	Investor-Owned	11,964,643 13%	4,017,524	4,879,464	3,067,655	-
4. Kenergy Corp	Cooperative	9,378,878 11%	710,953	302,766	8,365,159	-
5. Kentucky Power Co	Investor-Owned	7,122,459 8%	2,409,237	1,402,043	3,311,179	-
Total Sales, Top Five Providers		60,927,340	13,045,535	12,379,857	35,501,948	-
Percent of Total State Sales		69	50	65	81	-

See footnotes at end of tables.

Implied Total 88,300,493

Table 4. Electric Power Net Summer Capacity by Primary Energy Source and Industry Sector, 1990, 1995, and 2001 Through 2006
(Megawatts)

Energy Source	1990	1995	2001	2002	2003	2004	2005	2006	Percentage Share 1990	Percentage Share 2006
Kentucky										
Electric Utilities	**15,511**	**15,425**	**15,229**	**15,419**	**15,349**	**15,860**	**16,234**	**16,878**	**100.0**	**84.2**
Coal	14,306	14,011	12,561	12,496	12,435	12,441	12,621	12,670	92.2	63.2
Petroleum	185R	186R	122	108	108	72	72	70	1.2	0.3
Natural Gas	225R	439R	1,726	1,993	1,988	2,521	2,714	3,313	1.5	16.5
Hydroelectric	795	789	821	821	818	817	817	813	5.1	4.1
Other Renewables	-	-	-	-	-	9	10	12	-	0.1
Independent Power Producers and Combined Heat and Power	**-**	**4**	**2,350**	**3,704**	**3,719**	**3,767**	**3,767**	**3,169**	**-**	**15.8**
Coal	-	-	1,716	1,716	1,716	1,716	1,716	1,716	-	8.6
Petroleum	-	-	65	65	65	65	65	65	-	0.3
Natural Gas	-	-	518	1,872	1,887	1,943	1,943	1,343	-	6.7
Hydroelectric	-	-	-	-	-	-	-	2	-	*
Other Renewables	-	4	51	51	51	43	43	43	-	0.2
Total Electric Industry	**15,511**	**15,429**	**17,579**	**19,123**	**19,068**	**19,627**	**20,001**	**20,047**	**100.0**	**100.0**
Coal	14,306	14,011	14,277	14,212	14,151	14,157	14,337	14,386	92.2	71.8
Petroleum	185R	186R	187	173	173	137	137	135	1.2	0.7
Natural Gas	225R	439R	2,244	3,865	3,875	4,464	4,657	4,656	1.5	23.2
Hydroelectric	795	789	821	821	818	817	817	815	5.1	4.1
Other Renewables	-	4	51	51	51	52	53	55	-	0.3

See footnotes at end of tables.

Table 1-2

Table 9. Retail Electricity Sales Statistics, 2006

Item	Full Service Providers					Other Providers		Total
	Investor-Owned	Public	Federal	Cooperative	Facility	Energy	Delivery	
Kentucky								
Number of Entities	4	31	1	24	1	NA	NA	61
Number of Retail Customers	1,203,388	209,195	22	782,522	2	NA	NA	2,195,129
Retail Sales (thousand megawatthours)	40,758	7,055	14,675	26,128	127	NA	NA	88,743
Percentage of Retail Sales	45.93	7.95	16.54	29.44	0.14	NA	NA	100.00
Revenue from Retail Sales (million dollars)	2,288	433	530	1,561	4	NA	NA	4,817
Percentage of Revenue	47.50	9.00	11.00	32.41	0.09	NA	NA	100.00
Average Retail Price (cents/kWh)	5.61	6.14	3.61	5.98	3.40	NA	NA	5.43

Table 9 Notes: Data are shown for All Sectors. Full Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full Service Providers may purchase electricity from others *(such as independent Power Producers or other full service providers) prior to delivery. Other Providers sell either the energy or the delivery services, but not both. Sales volumes and customer counts shown for* Other Providers refer to delivered electricity, which is a joint activity of both energy and delivery providers; for clarity, they are reported only in the Energy column in this table. The revenue shown under Other Providers represents the revenue realized from the sale of the energy and the delivery services distinctly. "Public" entities include municipalities, State power agencies, and municipal marketing authorities. "Federal" entities are either owned or financed by the Federal Government. "Cooperatives" are electric utilities legally established to be owned by and operated for the benefit of those using its services. The cooperative will generate, transmit and/or distribute supplies of electric energy to a specified area not being serviced by another utility. "Facility" sales represent direct electricity transactions from independent generators to end use consumers.

Table 10. Supply and Disposition of Electricity, 1990, 1995, and 2001 Through 2006
(Million Kilowatthours)

Category	1990	1995	2001	2002	2003	2004	2005	2006
Kentucky								
Supply								
Generation								
Electric Utilities	73,807	86,162	83,678	80,162	80,697	82,921	85,680	86,816
Independent Power Producers	-	-	11,448	11,369	10,566	11,097	11,622	11,449
Electric Power Sector Generation Subtotal	**73,807**	**86,162**	**95,126**	**91,530**	**91,263**	**94,018**	**97,302**	**98,266**
Combined Heat and Power, Commercial	-	-	98	-	-	-	-	-
Combined Heat and Power, Industrial	-	4	194	576	456	512	521	526
Industrial and Commercial Generation Subtotal	**-**	**4**	**291**	**576**	**456**	**512**	**521**	**526**
Total Net Generation	**73,807**	**86,166**	**95,418**	**92,107**	**91,719**	**94,530**	**97,822**	**98,792**
Total Supply	**73,807**	**86,166**	**95,418**	**92,107**	**91,719**	**94,530**	**97,822**	**98,792**
Disposition								
Retail Sales								
Full Service Providers	61,097	74,548	79,975	87,267	85,176	86,521	89,218	88,616
Facility Direct Retail Sales	-	-	-	-	44	-	133	127
Total Electric Industry Retail Sales	**61,097**	**74,548**	**79,975**	**87,267**	**85,220**	**86,521**	**89,351**	**88,743**
Direct Use	**-**	**3**	**182**	**186**	**188**	**188**	**389**	**400**
Total International Exports	**-**	**-**	**-**	**-**	**-**	**-**	*****	**-**
Estimated Losses	**4,581**	**5,659**	**4,286**	**6,459**	**5,690**	**6,765**	**6,687**	**6,515**
Total Disposition	**65,678**	**80,211**	**84,444**	**93,912**	**91,098**	**93,475**	**96,428**	**95,659**
Net Interstate Trade	**8,130**	**5,955**	**10,974**	**-1,805**	**621**	**1,055**	**1,394**	**3,133**
Net Trade Index (ratio)	**1.12**	**1.07**	**1.13**	**0.98**	**1.01**	**1.01**	**1.01**	**1.03**

R = Revised.
NA = Not applicable; NM = Not meaningful.
W = Withheld to avoid disclosure of individual company data.
- = Data not available.
* = *Value is less than half of the smallest unit of measure (e.g., for values with no decimals, the smallest unit is 1 and values under 0.5 are shown as *.)*
Totals may not equal sum of components because of independent rounding.
Table 10 Notes: Estimated Losses are reported at the utility level, and then allocated to States based on the utility's retail sales by State. Reported losses may include electricity unaccounted for by the utility. Net Interstate Trade represents the difference between the amount of electricity produced in the State and consumed in the State. Positive values indicate a State that is a net interstate exporter of electricity; negative values indicate a State that is a net interstate importer of electricity. The Net Trade Index represents a State's electricity self-sufficiency. Values greater than 1 indicate that, on an annual net basis, the State supplied electricity consumed outside the State; values less than 1 indicate that, on an annual net basis, the State consumed electricity produced outside the State.
General Notes: Table 4 "Other Renewables" includes wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind. The "Other" category includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies. However, Table 5 "Other Renewables" includes only biogenic municipal *solid waste, in addition to wood, black liquor, other wood waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal,* photovoltaic energy, and wind. In Table 5 "Other" includes Non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies. In Table 7, "Other Renewables" emissions include biogenic municipal solid waste, and other renewable waste.
Direct use is commercial or industrial use of electricity that (1) is self-generated (2) is produced by either the same entity that consumes the power or an affiliate, and (3) is used in direct support of a service or industrial process located within the same facility or group of facilities that houses the generating equipment. Direct use is exclusive of station use.

FN 7

Table 3. Top Five Retailers of Electricity, with End Use Sectors, 2006
(Megawatthours)

Entity	Type of Provider	All Sectors	Residential	Commercial	Industrial	Transportation
Kentucky						
1. Kentucky Utilities Co	Investor-Owned	17,786,364	5,907,821	5,795,584	6,082,959	-
2. Tennessee Valley Authority	Federal	14,674,996	-	-	14,674,996	-
3. Louisville Gas & Electric Co	Investor-Owned	11,964,643	4,017,524	4,879,464	3,067,655	-
4. Kenergy Corp	Cooperative	9,378,878	710,953	302,766	8,365,159	-
5. Kentucky Power Co	Investor-Owned	7,122,459	2,409,237	1,402,043	3,311,179	-
Total Sales, Top Five Providers		60,927,340	13,045,535	12,379,857	35,501,948	-
Percent of Total State Sales		69	50	65	81	-

See footnotes at end of tables.

Table 4. Electric Power Net Summer Capacity by Primary Energy Source and Industry Sector, 1990, 1995, and 2001 Through 2006
(Megawatts)

Energy Source	1990	1995	2001	2002	2003	2004	2005	2006	Percentage Share 1990	Percentage Share 2006
Kentucky										
Electric Utilities	**15,511**	**15,425**	**15,229**	**15,419**	**15,349**	**15,860**	**16,234**	**16,878**	**100.0**	**84.2**
Coal	14,306	14,011	12,561	12,496	12,435	12,441	12,621	12,670	92.2	63.2
Petroleum	185R	186R	122	108	108	72	72	70	1.2	0.3
Natural Gas	225R	439R	1,726	1,993	1,988	2,521	2,714	3,313	1.5	16.5
Hydroelectric	795	789	821	821	818	817	817	813	5.1	4.1
Other Renewables	-	-	-	-	-	9	10	12	-	0.1
Independent Power Producers and Combined Heat and Power	-	4	2,350	3,704	3,719	3,767	3,767	3,169	-	15.8
Coal	-	-	1,716	1,716	1,716	1,716	1,716	1,716	-	8.6
Petroleum	-	-	65	65	65	65	65	65	-	0.3
Natural Gas	-	-	518	1,872	1,887	1,943	1,943	1,343	-	6.7
Hydroelectric	-	-	-	-	-	-	-	2	-	*
Other Renewables	-	4	51	51	51	43	43	43	-	0.2
Total Electric Industry	**15,511**	**15,429** (4)	**17,579**	**19,123**	**19,068**	**19,627**	**20,001**	**20,047** (2)	**100.0**	**100.0**
Coal	14,306	14,011 (3)	14,277	14,212	14,151	14,157	14,337	14,386 (1)	92.2	71.8
Petroleum	185R	186R	187	173	173	137	137	135	1.2	0.7
Natural Gas	225R	439R	2,244	3,865	3,875	4,464	4,657	4,656	1.5	23.2
Hydroelectric	795	789	821	821	818	817	817	815	5.1	4.1
Other Renewables	-	4	51	51	51	52	53	55	-	0.3

See footnotes at end of tables.

(1) (2)
14,386 ÷ 20,047 = 71.76%

(3) (4)
14,011 ÷ 15,429 = 90.81%

Table 5. Electric Power Net Generation by Primary Energy Source and Industry Sector, 1990, 1995, and 2001 Through 2006
(Megawatthours)

Energy Source	1990	1995	2001	2002	2003	2004	2005	2006	Percentage Share	
									1990	2006
Kentucky										
Electric Utilities	**73,807,286**	**86,161,578**	**83,677,982**	**80,161,524**	**80,696,982**	**82,921,402**	**85,679,912**	**86,816,479**	**100.0**	**87.9**
Coal	70,500,461	82,539,467	79,381,504	75,308,162	76,367,048	78,574,428	81,188,722	83,068,626	95.5	84.1
Petroleum	118,646	130,598	120,418	135,412	130,280	93,651	96,557	79,520	0.2	0.1
Natural Gas	27,796	68,035	320,552	693,201	229,930	398,814	1,349,378	963,428	*	1.0
Other Gases	-	-	-	-	-	1,701	4,991	3,836	-	*
Hydroelectric	3,160,383	3,423,478	3,855,508	4,024,749	3,948,052	3,780,251	2,961,193	2,591,701	4.3	2.6
Other Renewables	-	-	-	-	-	57,029	62,098	87,713	-	0.1
Other	-	-	-	-	21,672	15,528	16,973	21,655	-	*
Independent Power Producers and Combined Heat and Power	-	**4,258**	**11,739,644**	**11,945,144**	**11,021,838**	**11,608,545**	**12,142,507**	**11,975,535**	-	**12.1**
Coal	-	-	11,417,074	7,966,084	7,693,492	7,546,083	7,894,391	8,129,862	-	8.2
Petroleum	-	-	3,142	2,933,086	2,814,631	3,527,448	3,584,128	3,261,378	-	3.3
Natural Gas	-	-	309,875	680,509	214,475	180,415	303,701	212,618	-	0.2
Other Renewables	-	4,258	9,553	365,465	299,240	354,600	360,287	371,677	-	0.4
Total Electric Industry	**73,807,286**	**86,165,836** (8)	**95,417,626**	**92,106,668**	**91,718,820**	**94,529,947**	**97,822,419**	**98,792,014** (6)	**100.0**	**100.0**
Coal	70,500,461	82,539,467 (7)	90,798,578	83,274,246	84,060,540	86,120,511	89,083,113	91,198,488 (5)	95.5	92.3
Petroleum	118,646	130,598	123,560	3,068,498	2,944,911	3,621,099	3,680,685	3,340,898	0.2	3.4
Natural Gas	27,796	68,035	630,427	1,373,710	444,405	579,229	1,653,079	1,176,046	*	1.2
Other Gases	-	-	-	-	-	1,701	4,991	3,836	-	*
Hydroelectric	3,160,383	3,423,478	3,855,508	4,024,749	3,948,052	3,780,251	2,961,193	2,591,701	4.3	2.6
Other Renewables	-	4,258	9,553	365,465	299,240	411,629	422,385	459,390	-	0.5
Other	-	-	-	-	21,672	15,528	16,973	21,655	-	*

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices and Quality for Coal, Petroleum, and Natural Gas, 1990, 1995, and 2001 Through 2006

Fuel, Quality	1990	1995	2001	2002	2003	2004	2005	2006
Kentucky								
Coal (cents per million Btu)	119	111	110	119	123	137	W	170
Average heat value (Btu per pound)	11,558	11,625	11,425	11,464	11,498	11,550	11,620	11,568
Average sulfur Content (percent)	2.59	2.42	2.15	2.16	2.12	2.09	2.21	2.23
Petroleum (cents per million Btu)	575	318	567	465	W	W	117	127
Average heat value (Btu per gallon)	138,943	118,024	139,286	137,640	132,664	131,967	132,710	132,305
Average sulfur Content (percent)	0.28	1.91	0.27	1.04	3.90	4.79	5.11	5.23
Natural Gas (cents per million Btu)	298	294	459	351	658	W	949	W
Average heat value (Btu per cubic foot)	1,020	1,022	1,020	1,003	1,017	1,017	1,026	1,025

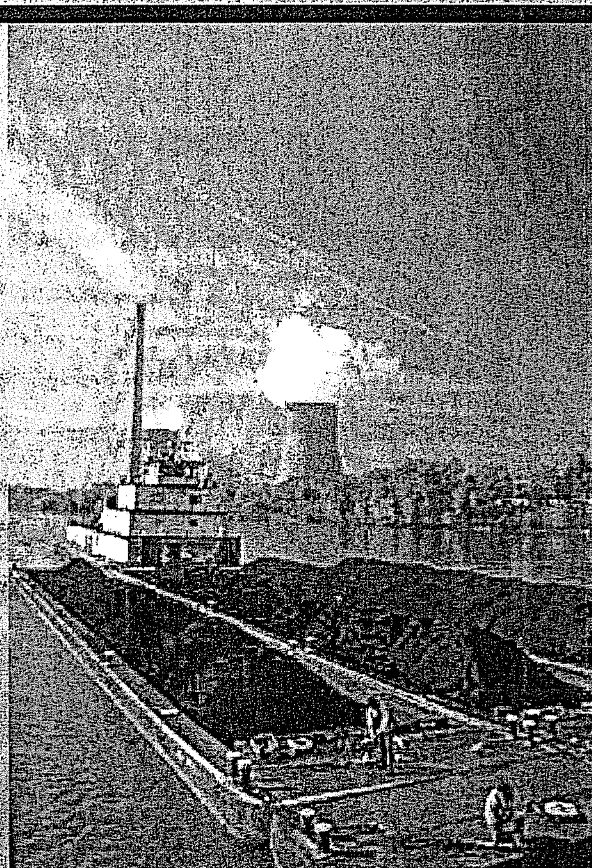
See footnotes at end of tables.

(5) 91,198,488 ÷ (6) 98,792,014 = 92.31% ✓

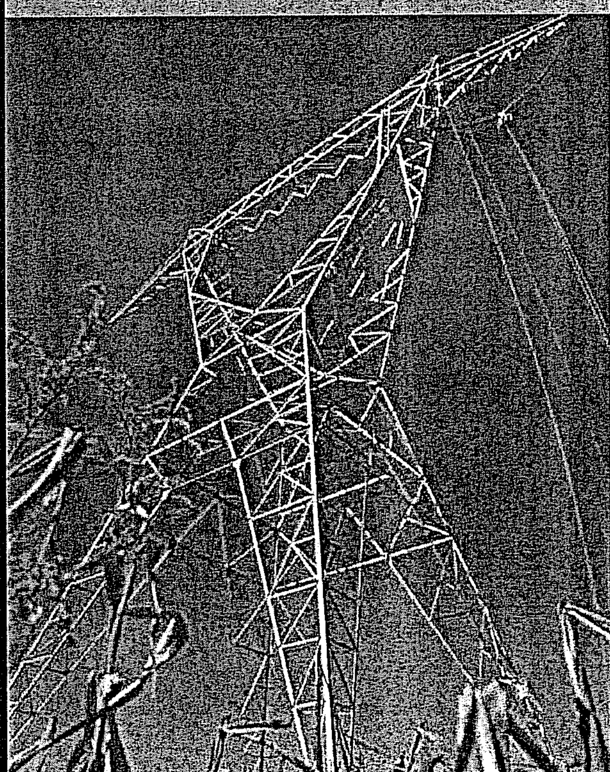
(7) 82,539,467 ÷ (8) 86,165,836 = 95.79% ✓

FN 10

42nd EEI Financial Conference



2007 Fact Book



Orlando, FL

November 4-7, 2007

AEP AMERICAN® ELECTRIC POWER

Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	in-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

FN 12

In the Matter of:

The 2005 Joint Integrated Resource Plan of	)
Louisville Gas and Electric Company and	) Case No.
Kentucky Utilities Company	) 2005-00162

VOLUME I – REDACTED
INTEGRATED RESOURCE PLAN

FILED: April 21, 2005

Location of Exempt Wholesale Generators ("EWGs") near or within the Companies' service territory may continue as the deregulated wholesale power marketplace evolves. The Companies anticipate receiving offers on occasion from EWG's to supply capacity needs and thus will include EWG's in any Requests for Proposals for purchased power that may be issued by the Companies in the future.

New Power Plants

The plan described in Table 5.(4) calls for Trimble County Unit 2, six new Greenfield combustion turbines and one Greenfield supercritical high sulfur coal unit. Clearly, new power plants are the most significant component of the 15-year least-cost plan.

Transmission Improvements

The Companies routinely identify transmission construction projects and upgrades required for maintaining the adequacy of its transmission system to meet projected customer demands. The construction projects currently identified are included in Volume III, Technical Appendix under the section labeled *Transmission Projects*.

Bulk Power Purchase and Sales and Interchange

The Companies have purchase power arrangements with Owensboro Municipal Utilities ("OMU"), Ohio Valley Electric Corporation ("OVEC") and Electric Energy, Inc. ("EEInc.") to provide additional sources of capacity. Under the OMU agreement, the Companies purchase (on an economic basis) the output not needed by OMU's system from two coal-fired, baseload units (combined capacity of approximately 400 megawatts). For 2005, the Companies expect to receive 196 megawatts of capacity from OMU. For each year after 2005, the expected capacity available to KU is projected to decrease due to the increases in OMU's customer load.

On May 11, 2004 the City of Owensboro, Kentucky and Owensboro Municipal Utilities filed suit against Kentucky Utilities Company in Daviess County, Kentucky District Court concerning a long-term power supply contract ("OMU Agreement") between KU and OMU. The dispute involves interpretational differences regarding certain issues under the OMU Agreement, including various payments or charges between KU and OMU, rights to excess power from the Smith units above that required to serve the OMU load, the ability to terminate the OMU Agreement and allocation between KU and OMU of the NO_x emissions allowances issued by the EPA. Kentucky Utilities removed the case to federal court in the Western District of Kentucky and filed an answer in that court denying the OMU claims and presenting certain counterclaims.

OVEC was formed for the purpose of providing electric power requirements projected for the uranium enrichment complex being built near Portsmouth, Ohio. However, beginning August 31, 2001, the power and energy from these plants was released from the original purpose and became available to the sponsoring companies. The Companies currently have access to 9.5% of the capacity and energy, which is approximately 225 MW of the installed capacity or approximately 209 MW reliably during the summer peak and varying capacity during the remaining months due to unit maintenance schedules. However, the Inter-Company Power Agreement ("ICPA") was renewed in 2004 and the Companies combined sponsorship will be 8.13% beginning in April 2006. Further details about OVEC and the Companies' sponsorship are contained in Section 6.

9/30/06 KU 10-Q

OMU LITIGATION

In May 2004, the City of Owensboro, Kentucky and Owensboro Municipal Utilities (collectively "OMU") commenced a suit now removed to the U.S. District Court for the Western District of Kentucky, against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. The dispute involves interpretational differences regarding issues under the OMU Agreement, including various payments or charges between KU and OMU and rights concerning excess power, termination and emissions allowances. The complaint seeks approximately $6 million in damages for periods prior to 2004 and OMU is expected to claim further amounts for later-occurring periods. OMU has additionally requested injunctive and other relief, including a declaration that KU is in material breach of the contract. KU has filed an answer in that court denying the OMU claims and presenting counterclaims. During 2005, the FERC declined KU's application to exercise exclusive jurisdiction over the matter. In July 2005, the district court resolved a summary judgment motion made by KU in OMU's favor, ruling that a contractual provision grants OMU the ability to terminate the contract without cause upon four years' prior notice, for which ruling KU retains certain rights to appeal. At this time the district court case is in the discovery stage and currently a trial date of January 2008 has been scheduled. In May 2006, OMU issued a notification of its intent to terminate the contract in May 2010, without cause, absent any earlier relief which may be permitted by the proceeding.

FN 14

(6) I have made copies for you of the studies that I have surveyed. I have also copied the relevant pages from earlier editions of Coal Facts that contain the results of earlier versions and updates of the Haywood/Baldwin studies. These might be useful because the present the data in varying ways and in varying levels of detail and have differing emphases in places.

(7) **PLEASE NOTE THAT THE 2007 HAYWOOD/BALDWIN STUDY (I.E., THE "UPDATED TO 2006" REPORT) IS INCORRECT RE THE VALUE OF PRODUCT.** They report $4.470 billion. The figure should be $4.975 billion. See the COAL FACTS page on severance tax. The value of product is the gross value of severed coal plus the gross value of processing. H/B only reported the first column. This is a mystery to me since they included the gross value of processing in the past. See, for example, p. 16 of the <u>2005-2006 Coal Facts</u>. There they report that the industry is a $4.13 billion industry. On p. 14 of the same <u>Coal Facts</u>, the total of the gross value of severed coal and the gross value of coal processing is $4.13. **THE INCORRECT VALUE CAUSES ALL OF THEIR FINDINGS TO BE LOW. THE ADDITIONAL ECONOMIC ACTIVITY SHOULD BE HIGHER (WHEN THEY APPLY THE MULTIPLIER), TAXES SHOULD BE HIGHER, ETC. ETC.**

(8) I have included for your reference a set of updated tables for the next (2008-2009) edition of <u>Coal Facts</u>. So, before you use data from the <u>2005-2006 Coal Facts</u>, please check and see if the data have been updated. The attachments to the data sheets are from the new data sets.