CASE NUMBER:

99-437

INDEX FOR CASE: 1999-437
AMERICAN ELECTRIC POWER
Integrated Resource Plan

IN THE MATTER OF THE INTEGRATED RESOURCE PLANNING REPORT OF
KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER TO THE
KENTUCKY PUBLIC SERVICE COMMISSION, OCTOBER, 1999

SEQ NBR	ENTRY DATE	REMARKS
0001	10/21/1999	Application.
0002	10/22/1999	Acknowledgement letter.
0003	11/09/1999	Letter granting petition for confidentiality filed 10/21/99 by AEP.
0004	11/15/1999	Order setting forth the procedural schedule to be followed in this case.
M0001	11/15/1999	E BLACKFORD AG-MOTION TO INTERVENE NOTICE OF FILING & CERTIFICATE OF SERVICE
M0003	11/16/1999	KY NATURAL RESOURCES IRIS SKIDMORE-MOTION FOR LEAVE TO INTERVENE
M0002	11/22/1999	MIKE KURTZ KIUC-PETITION TO INTERVENE
0005	11/23/1999	Order granting motion of the NREPC to intervene.
0006	11/23/1999	Order granting motion of Attorney General to intervene.
M0004	12/01/1999	MICHAEL FORBES UAW LEGAL SERVICES PL-REQUEST FOR PSC TO INTERVENE
0007	12/09/1999	Commission staff's request for information to KY Power - AEP response 1/13/2000.
M0006	12/16/1999	E BLACKFORD AG-MOTION FOR EXTENSION OF TIME
0008	12/17/1999	Order granting motion of the KIUC to intervene.
M0005	12/17/1999	E BLACKFORD AG-INITIAL REQUEST FOR INFORMATION
M0007	12/20/1999	NATURAL RESOURCES & ENVIROMENTAL PRO-MOTION FOR EXTENSION OF TIME
M0008	12/20/1999	NATURAL RESOURCES & ENVIRO PROTECTIO-REQUEST FOR INFORMATION TO THE KY POWER CO
0009	12/29/1999	Order ent.,AG's initial requests now due 12/16;KDOE's intial req's due 12/20. 0
M0009	01/13/2000	BRUCE CLARK AMERICAN ELECTRIC PO-RESPONSE TO FIRST SET OF DATA REQ PURSUANT TO ORDER OF DEC
M0010	01/24/2000	JUDITH VILLINES AMERICAN ELECTRIC P-RESPONSE TO AG 1ST SET OF DATA REQ ON DEC 16,99
M0011	01/26/2000	JUDITH VILLINES AMERICAN ELEC POWER-RESPONSE TO KDOE DATA REQ 1 SET DATED DEC 20,99
M0012	02/07/2000	E BLACKFORD AG-SUPPLEMENTAL REQ FOR INFORMATION
M0013	02/08/2000	IRIS SKIDMORE NATURAL RESOURCES-SECOND REQ FOR INFORMATION TO KY POWER CO
0010	02/09/2000	Commission Staff's Data Request to Kentucky Power Company.
M0014	02/29/2000	KY POWER-RESPONSE TO KDOE 2ND SET DATA REQ DATED FEB 8,00
M0015	02/29/2000	JUDITH VILLINES AMERICAN ELECTRIC PO-RESPONSE TO AG 2ND SET OF DATA REQ DATED FEB 7,99
M0016	02/29/2000	KY POWER-RESPONSE TO PSC STAFF 2ND SET DATA REQ DATED FEB 8,99
0011	03/24/2000	Informal Conference Memorandum; comments, if any, due 4/3/2000.
M0017	03/29/2000	E BLACKFORD AG-COMMENTS OF AG ON THE 99 IRP
M0018	03/31/2000	KY DIVISION OF ENERGY-COMMENTS RELATED TO KY POWER 99 IRP PLANNING REPORT TO THE PSC
M0019	04/19/2000	N. TIBBERTS/KENTUCKY POWER COMPANY-REPLY COMMENTS TO ATTORNEY GENERAL AND KENTUCKY DIVISION
M0020	05/05/2000	GEOFFREY YOUNG/NATURAL RESOURCES-MOTION FOR AN AMENDMENT TO THE PROCEDURAL SCHEDULE
M0021	05/25/2000	JUDITH VILLINES/KY POWER d/b/a AEP-OPPOSITION OF KY POWER TO MOTION FOR AN AMENDMENT TO PRO
0012	05/31/2000	Order granting motion; DOE's tendered additional comments are accepted.
0013	06/21/2000	Staff Report
0014	06/29/2000	Final Order closing case.

COMMONWEALTH OF KENTUCKY
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CERTIFICATE OF SERVICE

RE: Case No. 1999-437
AMERICAN ELECTRIC POWER

I, Stephanie Bell, Secretary of the Public Service Commission, hereby certify that the enclosed attested copy of the Commission's Order in the above case was served upon the following by U.S. Mail on June 29, 2000.

See attached parties of record.

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

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COMMONWEALTH OF KENTCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING REPORT OF THE KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER TO THE KENTUCKY PUBLIC SERVICE COMMISSION, OCTOBER 1999	)	CASE NO. 99-437

ORDER

The Commission initiated this proceeding in order that its Staff might conduct a review of the 1999 integrated resource plan ("IRP") submitted by Kentucky Power Company d/b/a American Electric Power ("Kentucky Power") pursuant to 807 KAR 5:058. Intervening in this case were the Attorney General's Utility and Rate Intervention Division and the Natural Resources and Environmental Protection Cabinet, Division of Energy.

Pursuant to 807 KAR 5:058, Section 12, the Commission Staff has issued a report on its review of Kentucky Power's 1999 IRP. Issuance of this report concluded the Staff's review of Kentucky Power's 1999 IRP.

IT IS THEREFORE ORDERED that this case is closed and removed from the Commission's docket.

Done at Frankfort, Kentucky, this 29th day of June, 2000.

By the Commission

ATTEST:

Executive Director

Paul E. Patton, Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Martin J. Huelsmann
Executive Director
Public Service Commission

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Edward J. Holmes
Vice Chairman

Gary W. Gillis
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June 21, 2000

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RE: Case No. 99-437 - Kentucky Power Company

Dear Ms. Blackford and Gentlemen:

Attached is a copy of the Commission Staff Report on the Integrated Resource Plan of Kentucky Power Company D/B/A American Electric Power ("Kentucky Power") which has been filed into the record of the above-referenced case. This report, prepared pursuant to 807 KAR 5:058, Section 12(3), summarizes the Staff's review of Kentucky Power's integrated resource plan filing and related information.

Sincerely,

Martin J. Huelsmann
Executive Director

Attachment

Paul E. Patton, Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Martin J. Huelsmann
Executive Director
Public Service Commission

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Chairman

Edward J. Holmes
Vice Chairman

Gary W. Gillis
Commissioner

MEMORANDUM

TO: Main Case File
Case No. 99-437

FROM: Case No. 99-437 Team

DATE: June 21, 2000

SUBJECT: Commission Staff Report

Attached for filing in this case is the Commission Staff Report on the Integrated Resource Plan of Kentucky Power Company D/B/A American Electric Power ("Kentucky Power"). This report, prepared pursuant to 807 KAR 5:058,Section 12(3), summarizes the Staff's review of Kentucky Power's integrated resource plan.

cc: Parties of Record

Kentucky Public Service Commission

Staff Report

On the

Integrated Resource Plan Report

Of Kentucky Power Company

Case No. 99-437

June 2000

Section 1
INTRODUCTION

In 1990, the Kentucky Public Service Commission (the Commission) established an integrated resource planning (IRP) process to provide for regular review by the Commission Staff of the long-range resource plans of the six major electric utilities under its jurisdiction. The Commission's goal in establishing the IRP process was to assure that all reasonable options for the future supply of electricity were being examined and pursued, and that ratepayers were being provided a reliable supply of electricity at the lowest possible cost.

Kentucky Power Company (Kentucky Power) submitted its 1999 IRP entitled Integrated Resource Planning Report to the Kentucky Public Service Commission in October 1999. Kentucky Power is one of seven electric utility operating companies which together comprise the American Electric Power (AEP) System. The major electric facilities of the seven companies are interconnected and centrally operated as a single integrated utility system. At the time of the 1999 IRP filing, AEP was undergoing regulatory review of a proposed merger with Central and South West Corporation.

Kentucky Power serves a population of about 386,000 in a 3,762 square mile area in eastern Kentucky. Kentucky Power serves approximately 170,000 residential, commercial and industrial customers, as well as providing electricity to other utility systems. Kentucky Power owns and operates the 1,060 MW coal-fired Big Sandy plant and has a 390 MW unit power agreement with the AEP Generating Company, an affiliate, for power from the Rockport plant in Indiana.

The report submitted by Kentucky Power provided its plan to meet customers' requirements over the 21-year planning period ending in 2019. Because Kentucky Power is part of an integrated electric utility system, the IRP also described the resource planning process and resulting plan of the AEP System.

The purpose of this report is to review and evaluate Kentucky Power's 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 and offer suggestions and recommendations to be considered in subsequent filings. Staff recognizes that resource planning is an ongoing and dynamic process. Thus, this review has been designed to offer suggestions to Kentucky Power on how to improve its 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 least-cost, least-risk plan for the ultimate customers served by Kentucky Power, recognizing the need to achieve a balance between the interests of ratepayers and shareholders.

The report also has an incremental component, noting any significant changes from Kentucky Power's most recent filing in 1996.

As part of the integrated AEP System, Kentucky Power's resource planning necessarily considers the plans of the AEP System as a whole. While load forecasts are developed for the Kentucky Power service territory, the load forecasts of all AEP operating companies are combined as a basis for determining future resource requirements. Demand-side and supply-side screening is conducted for the entire AEP System, as is the integration of supply and demand-side resource options and the development of the final resource plan.

Kentucky Power/AEP stated that it has adequate generation resources to meet its load requirements in the near term. In the longer term, with the additional supply side and DSM programs reflected in the IRP, Kentucky Power/AEP is expected to have adequate resources to serve its customers' requirements throughout the forecast period.

The remainder of this report is organized as follows:

- Section 2, Load Forecasting, provides a review of Kentucky Power's and AEP's projected load requirements and load forecasting methodology.
- Section 3, Demand-Side Management (DSM), summarizes Kentucky Power/AEP's evaluation of DSM opportunities.
- Section 4, Supply Side Resource Assessment, focuses on supply resources available to meet Kentucky Power/AEP's requirements.
- Section 5, Integration and Plan Optimization, discusses Kentucky Power/AEP's integrated assessment of supply and demand-side options into a resource plan.

Section 2
LOAD FORECASTING

INTRODUCTION

Kentucky Power's load forecasts are based mostly on econometric analysis of time-series data. Its energy requirements forecast is derived from two sets of econometric models – a set of monthly short-term models and a set of annual long-term models. For the first five forecast years through 2003, the forecast values are governed exclusively by the short-term models, while the last forecast year (2019) forecast values are governed by the long-term models. For the transition period 2004-2018, the forecast values are interpolated linearly between monthly values of the last short-term forecast year (2003) and the last forecast year (2019).

SHORT-TERM FORECASTING MODELS

Economic theory defines the short run as the period in which there are both variable and fixed factors. In the case of electricity, it is the stock of equipment that is essentially fixed in the short run, in which the consumption of electric energy is a function of the utilization rate of this equipment. For residential and commercial customers, weather is the most significant factor influencing the utilization rate, whereas for industrial customers, economic forces determine inventory levels and factory orders.

The goal of Kentucky Power's short-term forecasting models is to produce an accurate load forecast for five years into the future. Employing a combination of monthly and seasonal binary variables, time trends and monthly heating and cooling degree days accomplishes this. One assumption made in the case of the short-term forecasting models is that the error terms are autocorrelated, or related from one period to another. Thus, the model is estimated as an autoregressive one, which corrects for first-degree autocorrelation.

Kentucky Power disaggregates its energy sales into four general areas: Residential and Commercial, Industrial, Other, and Losses. The methodologies used for each area are discussed herein.

Aggregate residential and commercial energy sales are forecasted as described above, including binary variables to account for month-to-month variations in load due to non-weather causes, three powers of heating degree-days and two powers of cooling degree-days to capture the effects of weather, a time trend, and binaries to account for discrete changes in load.

Industrial energy sales are further broken down into Manufacturing and Mine Power Sales. In addition to monthly binaries, a time trend, and weather variables, the former includes the Federal Reserve Board (FRB) industrial production index for basic steel and the latter includes variables representing events such as the opening or closing of individual mines. The short-term forecasting model for Other energy sales, which is comprised of those for public street and highway lighting and sales to municipal customers, includes only monthly binaries and a time trend, while sales for resale also include weather variables.

In principle, short-term losses and unaccounted-for energy (i.e., "losses") are related to total energy, but in practice are often subject to significant discontinuities whose origin is often not well understood. Thus, the model specifications for this category for Kentucky Power include numerous binary variables.

LONG-TERM FORECASTING MODELS

The goal of Kentucky Power's long-term forecasting models is to produce a reasonable projection of load for up to 20 years in the future. As a result, the long-term models employ a full range of structural and demographic variables, input price variables, weather and other binary variables to produce forecasts conditioned on the outlook for the U.S. economy for the company's service area economy and for relative energy prices. While most of the explanatory variables enter the model in a straight-forward manner, the energy price variables enter in a lagged fashion.

The long-term models are estimated by Ordinary Least Squares, which makes no correction for autocorrelation. The estimation period for these models was 1975-1997. The energy forecasts actually used only one year (2019) generated by the long-term forecasting models. Linear interpolation was used to forecast the years between 2003 and 2019.

In order to produce forecasts of certain independent variables used in the internal requirements forecasting models, several supporting models were used, including a natural gas price model and a regional coal production model for the Kentucky Power service area.

In the long-term forecasts, energy sales are disaggregated into Residential, Commercial, Industrial, Other, and Losses. Hence, in this instance, energy sales to residential customers are separated from sales to commercial users. One difference is that the residential energy sales for Kentucky Power are forecasted using two models: the first projects the number of residential customers and the second projects the kWh usage per customer. The residential energy sales forecast is calculated as the product of the resulting customer and usage forecasts. The customer model employs a lagged dependent variable to represent the gradual adjustment of the number of residential customers to changes in total employment. The residential usage model includes service area total employment, heating and cooling degree-days and the real (effective) prices of natural gas and electricity.

A single model is used to forecast commercial energy sales. The model is specified as linear, with the dependent and independent variables in logarithm form. In general, regional economic activity, weather, and relative energy prices are considered to be the primary determinants of long-term commercial load growth.

The industrial energy sales models are broken down into Manufacturing and Mining Power. The manufacturing forecasting model relates sales to the FRB production index for manufacturing to the real prices of electricity and natural gas, and to service area manufacturing employment and binary variables. The other component, the model for Mine Power energy consumption, relates energy sales to regional local production, regional coal mining employment and the average electric price to Mine Power customers.

As in the short-term forecast, other energy sales are broken down into street and highway lighting, and municipal load. The former includes time-trend and binary variables and the latter includes demographic and economic trend variables. The two municipal customers, the cities of Vanceburg and Olive Hill, are treated as a single entity.

The final category, losses and unaccounted for energy, is modeled as a function of the Company's total internal energy sales and its estimated share of AEP System sales to non-affiliated companies. Binaries and a time-trend variable are used in the model.

SEASONAL PEAK INTERNAL DEMAND

Peak internal demands for Kentucky Power are forecasted using a regression model that relates monthly peak to monthly weather-normal energy, the average daily temperature on the day of the monthly peak, and a set of monthly and seasonal binary variables. The model is parameterized to allow for different effects of monthly weather-normal energy in different seasons, in which a season is defined as one of six two-month spans, the first of which is January-February. The estimation interval extends from January 1984 through August 1998 and the estimation procedure is ordinary least squares.

Uncertainty Analysis

For AEP, forecast uncertainty is of primary interest at the system level rather than the operating company level. Therefore, a "mini model" representative of the full AEP structure forecast was developed and the low and high values of the independent variables were determined and used as estimates. Following the determination of the low and high values, simulations using different variable values were performed. For AEP, the low case and high case energy forecasts for the last forecasted year, 2019, deviate by about minus and plus 9% from the base case forecast.

FORECAST RESULTS

Energy sales and peak demand forecasts for Kentucky Power are shown in Exhibit 1-1. Total internal energy requirements are expected to grow at a rate of 1.7% for Kentucky Power over the forecast period, from 6,992 GWh in 1998 to 10,136 GWh in

2019. Peak demand growth is forecast at 1.6% for the summer peak, increasing from 1,213 MW to 1,705 MW, and 1.8% for the winter peak, increasing from 1,432 MW to 2,090 MW.

Exhibit 1-2 shows AEP's energy sales and peak demand forecasts. AEP's internal generation requirements are projected to grow at a 1.2% rate, somewhat lower than Kentucky Power's. Kentucky Power's higher growth rate indicates that Kentucky Power will account for an increasing share of the AEP System's total energy requirements over the forecast period.

A comparison of Kentucky Power's 1999 forecast to its 1996 forecast indicates that total internal energy requirements are initially lower in the 1999 forecast but in the long term they become slightly higher. For instance, long-term sales growth of 1.6% was forecasted in the 1996 forecast, whereas sales growth of 1.7% is forecasted in the 1999 forecast. For the AEP System, the 1999 forecast for the year 2016 is 1.9% less than the 1996 forecast, and the long-term growth rate for the 1999 forecast is 1.2%, slightly lower than the 1996 forecast growth rate of 1.3%. Residential and commercial energy sales forecasts were increased by 7.8% and 11.0%, respectively, while the manufacturing and mine power sales forecasts were decreased by 3.4% and 7.8%, respectively.

For the increases in residential and commercial energy sales, Kentucky Power indicated that the use of an alternative regional economic forecast, coupled with a re-evaluation of expected long-term trends in residential consumption patterns, were the drivers of change. For the manufacturing sector, the overriding factor contributing to the decrease in the energy sales forecast was that anticipated load additions within the service area were smaller than expected.

DISCUSSION OF REASONABLENESS

In general, Staff is satisfied with Kentucky Power's forecasting. In its report on Kentucky Power's 1996 IRP filing, Staff had made the following recommendations:

1. Provide a full explanation for any changes in forecasting methodology including the pros and cons of the current and former methods.

2. Provide a comparison of forecasted winter and summer peaks with actual results for the period following Kentucky Power's 1996 IRP, along with a discussion of the reasons for the differences between forecasted and actual results.

3. Provide a comparison of the annual forecast of residential energy sales, using the current econometric models, with actual results for the period following the 1996 IRP. Include a discussion of the pros and cons of the current and former models.

EXHIBIT 1-1						
Kentucky Power Sales, Generation, and Peak Demand						
	Actual 1998	2003	2008	2014	2019	Growth Rate 1999-2019
Residential	2,156	2,499	2,777	3,112	3,390	1.9%
Commercial	1,195	1,399	1,600	1,841	2,042	2.5%
Industrial	3,131	3,298	3,530	3,807	4,039	1.2%
"Other"	91	95	110	127	142	2.2%
Total Internal	6,573	7,291	8,017	8,887	9,613	
Losses	419	455	476	502	523	0.8%
Internal Generation Requirements	6,992	7,746	8,493	9,389	10,136	1.7%
Winter Peak Demand	1,432	1,570	1,732	1,926	2,090	1.8%
Summer Peak Demand	1,213	1,312	1,434	1,582	1,705	1.6%

EXHIBIT 1-2						
AEP Sales, Generation, and Peak Demand						
	Actual 1998	2003	2008	2014	2019	Growth Rate 1999-2019
AEP Internal Generation Requirements (GWh)	117,071	122,358	131,408	142,269	151,320	1.2%
Kentucky Power's Share of AEP System	6.0%	6.3%	6.5%	6.6%	6.7%	
AEP Summer Peak Demand (MW)	19,414	20,757	22,411	24,395	26,049	1.4%
Kentucky Power's Share of AEP System	6.2%	6.3%	6.4%	6.5%	6.5%	
AEP Winter Peak Demand (MW)	18,546	20,244	21,687	23,419	24,873	1.3%
Kentucky Power's Share of AEP System	7.7%	7.8%	8.0%	8.2%	8.4%	

4. Kentucky Power should, to the extent possible, report on and reflect in its forecasts, the impacts of increasing wholesale and retail competition in the electric industry.

5. Kentucky Power should attempt, either in its forecasts or in its uncertainty analysis, to incorporate the impacts of potential environmental costs such as those associated with potential NO_x reductions that might be imposed on sources in the Eastern United States.

Kentucky Power addressed these recommendations on Pages 2-15 and 2-16 of its IRP. It indicated there had been no change in its load forecasting methodology since 1996 and it provided the comparisons of its actual results and its forecasts for the period 1996-1998. Kentucky Power stated that, with no definitive and comprehensive plan for deregulation of the electric industry having been developed, its forecast was prepared without any speculation on the outcome of industry deregulation. In the same vein, Kentucky Power indicated that because no clear guidelines on stricter NO_x emissions requirements existed at the time its forecast was prepared, it had not conducted any analyses on the possible effects of potentially stricter emissions requirements.

Staff accepts these responses to its earlier recommendations. However, we believe 5 comparable recommendations are equally valid for Kentucky Power's response in its next IRP. Therefore, Staff has the following recommendations for Kentucky Power's consideration in preparing its next IRP filing.

1. Provide a full explanation for any changes in forecasting methodology.

2. Provide a comparison of forecasted winter and summer peak demands with actual results for the period following Kentucky Power's 1999 IRP, along with a discussion of the reasons for the differences between forecasted and actual peak demands.

3. Provide a comparison of the annual forecast of residential energy sales, using the current econometric models, with actual results for the period following the 1999 IRP. Include a discussion of the reasons for the differences between forecasted and actual results.

4. Kentucky Power should, to the extent possible, report on and reflect in its forecasts, the impacts of increasing wholesale and retail competition in the electric industry.

5. Kentucky Power should attempt, either in its forecasts or in its uncertainty analysis, to incorporate the impacts of potential environmental costs such as those associated with potential NO_x reductions imposed on sources in the Eastern United States.

Section 3
DEMAND-SIDE MANAGEMENT

INTRODUCTION

In its 1999 IRP filing, Kentucky Power set forth its overall objectives for its demand-side management (DSM) activities. Those objectives are the same as has been detailed in the 1996 IRP and are as follows:

1. Promote energy conservation among all customer classes.
2. Reduce future peak demands.
3. Continue efforts and programs designed to provide the best possible service to customers.
4. Promote electric applications that improve system load factor.
5. Strive to retain existing customers.
6. Encourage new off-peak electrical applications.
7. Provide guidance and assistance to customers facing equipment replacement decisions.

The DSM screening and program evaluation processes employed by Kentucky Power/AEP are discussed below.

SCREENING METHODOLOGY

The 1999 DSM screening methodology reduced the number of screening stages by combining both the measure-screening and program-screening processes that had been included in the 1996 screening methodology. Kentucky Power has worked with the Kentucky Power Company DSM Collaborative, which was established in November 1994 to implement DSM projects, and the DSM Collaborative has continued to be the decision-maker on the program-screening process since the initial design and implementation of these programs.

The DSM Collaborative had re-screened and re-evaluated the DSM programs implemented in January 1996 and had redesigned and reevaluated the programs to improve their cost effectiveness and better target customers for the programs. These efforts resulted in the discontinuation of two programs, the Compact Fluorescent Bulb Program in 1996 and the Energy Fitness Program in 1999. In addition, the Mobile Home New Construction Program was expanded to a full-scale implementation program and design changes were made in the Targeted Energy Efficiency Program to improve its cost effectiveness.

The DSM screening process looked at the cost-benefit of each of the DSM programs initially approved by the Collaborative for implementation. The supply-side benefits were avoided energy costs and avoided demand costs based on marginal $/MWH and $/KW, respectively. Avoided demand cost was based on average demand impacts of the DSM measures at AEP's winter and summer peak. The avoided demand cost was calculated based on avoidance of a combustion turbine in summer 2005. Avoided transmission and distribution costs were estimated based on historical and projected capital expenditures for load growth. SO_2 emission credits and expected additional system sales were factored in and reductions in CO_2 and NOx emissions were estimated but not in dollar value. Measures were evaluated on a 20-year planning horizon using four cost benefit tests. The tests were the total resource cost (TRC) test, the ratepayer impact measure (RIM) test, the utility cost (UC) test and the participant (P) test, known as the "California Tests" as defined in the Standard Practice Manual, Economic Analysis of Demand-Side Management Programs issued by the California Public Utilities Commission and California Energy Commission, December 1987. Under the TRC test, the benefits and costs are viewed from the combined perspective of the utility and the participant, whereas under the RIM test, the benefits and costs are viewed from the ratepayer's perspective. The benefits and costs under the UC test are viewed from the utility's perspective, while under the P test they are viewed from the participant's perspective.

PROGRAM EVALUATION

The updated cost-benefit evaluations resulted in 8 expanded DSM programs for the AEP System and Kentucky Power. Of the 8 programs, the Collaborative requested to extend 6 of them for three years in the DSM Collaborative Report filed with the Commission on August 16, 1999. Five of the 6 programs were cost effective based on the TRC test, with benefit/cost ratios greater than 1.0. The only continuous program which was not cost effective on a stand-alone basis was the Targeted Energy Efficiency ("TEE") program, but Kentucky Power requested its continuation due to its impact on reducing consumption, making bills more affordable and reducing the level of customer arrearages, collection costs and uncollectible accounts that it incurred.

On February 28, 2000, the Commission issued an Order approving Kentucky Power's continuing DSM program for an additional three years.[1] In that Order, the Commission reiterated its concerns about continuing DSM programs that are not cost effective or that appear incapable of being made cost effective, and the Commission encouraged Kentucky Power to seek out ways to improve the cost effectiveness of the TEE program and to attempt to serve a larger percentage of non-electric hearing customers as a means of improving the program's overall cost effectiveness. The Commission also required Kentucky Power to file, on an annual basis, separate impact evaluations of the residential and commercial DSM programs being continued. In addition, the Commission required Kentucky Power to file separate benefit-cost evaluations for the first two years of the three-year extension by no later than August

[1] Case No. 95-427, The Joint Application Pursuant to 1994 House Bill No. 501 for the Approval of American Electric Power/Kentucky Power Company ("AEP/Kentucky") Collaborative Demand-Side Management Programs, and for Authority to Implement a Tariff to Recover Costs, Net Lost Revenues and Receive Incentives Associated with the Implementation of the AEP/Kentucky Collaborative Demand-Side Management Programs.

15, 2002. Moreover, the Commission ordered that Kentucky Power, at the end of the three-year extension, shall discontinue or modify any DSM program that is not cost effective or does not produce other benefits to the company or its ratepayers.

On March 28, 2000, the Commission issued an Order approving a filing by AEP/Kentucky's DSM Collaborative to eliminate the balance of over-collections from the industrial class by allocating it to the residential and commercial class.[2] However, that filing did not include any new programs or modifications to any existing programs.

In summary, with the changes noted above, Kentucky Power's continuing DSM plan consists of four residential programs and two commercial programs, with a projected total budget of approximately $1,030,000 for calendar year 2000. In addition to the TEE, the other three residential programs are known as High-Efficiency Heat Pumps Retrofit, Mobile Home High Efficiency Heat Pumps and Mobile Home New Construction. The two commercial programs are known as Smart Incentive and Smart Audit.

INTERVENOR COMMENTS

The Kentucky Division of Energy (DOE) provided extensive comments relative to Kentucky Power's DSM efforts. Among its comments were criticisms that Kentucky Power had declined to analyze any potential new DSM options or programs; that it declined to analyze demand-side and supply-side options on a consistent, quantitative basis - instead making the assumption that all future needs would be met by new generation and interruptible loads; that its existing DSM programs are capped at a "token" level; and that AEP has made a decision at the corporate level not to consider, propose, or initiate any major new DSM programs. To correct for these perceived shortfalls, the DOE suggested that the company should refocus its perspective from being an "electron vendor" to one of being an energy service company, and it made the following specific recommendations to Kentucky Power and/or AEP:

- Establish an AEP-owned energy service company (ESCO) or form joint ventures with (or purchase) one or more existing ESCOs.
- Use Local Integrated Resource Planning (LIRP).
- Initiate a comprehensive program in New Commercial Construction.
- Promote Cogeneration to Gain Thermal Efficiencies.
- Promote Distributed Generation and Green Power through net metering.
- Support statewide and regional market transformation initiatives.

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[2] Case No. 2000-070, The Demand Side Management Program and Demand Side Management Program Cost Recovery Filing of American Electric Power/Kentucky Power.

The DOE concluded its comments by suggesting that Kentucky Power focus on TRC analysis to identify new energy service offerings, shared savings arrangements, or market transformation initiatives with large savings potential.

In response, Kentucky Power noted that many of the problems discussed by DOE were institutional in nature and therefore could not be solved by any one entity alone. Nonetheless, Kentucky Power noted that while buildings and energy-using equipment are not as efficient as they could be, they are significantly more efficient in the 1990s then they were in the late 1970s due to efforts by various segments of society. Kentucky Power cited its two commercial DSM programs as examples of its contribution to addressing market barriers.

In addition, the Company denied that it has foreclosed future DSM options and maintained that it continues to give proper and appropriate consideration to both supply-side resources and demand-side programs. The Company also suggested that the TRC test advocated by DOE is less appropriate as the industry moves to a competitive retail environment. Furthermore, AEP stated that it has already initiated what DOE calls "a comprehensive re-examination of its relationship to the market," and that it is in a better position than an outside entity to determine the most appropriate programs to be implemented in its service territory.

The company summarized its rebuttals by suggesting that DOE's comments do not give adequate and accurate consideration to Kentucky Power's ongoing efforts or to the real world barriers that come into play. However, Kentucky Power did not directly address its position relative to most, if not all, of the six specific recommendations made by DOE. In its next IRP filing, Kentucky Power should discuss its position relative to those recommendations, including any efforts to implement the programs, technologies, or initiatives suggested by DOE.

DISCUSSION OF REASONABLENESS

In its report on Kentucky Power's 1996 IRP report, Staff made the following recommendations relative to DSM:

1. Expand on its statement that DSM will diminish in a competitive market.

2. Provide an analysis of the effects of wholesale competition on its DSM programs since their inception.

3. Provide a forecast of expected DSM given both wholesale and retail competition and compare the results with a DSM forecast based on continued regulation.

4. Estimate the effects on its avoided cost of EPA's NOx standards. Attempt to estimate the effect of CO_2 costs and provide a full description of how

these environmental costs are factored into program screening and evaluation.

5. Provide a complete description of how current programs are re-screened and re-evaluated.

Kentucky Power addressed these recommendations of Pages 3-7 through 3-10 of its IRP filing. It indicated it had streamlined its screening methodology by combining its measure-screening and program-screening processes. Kentucky Power stated it had factored CO_2 and NO_x emissions reductions into its DSM cost-benefit analysis but had assigned them no specific dollar values because there are no existing market values for either CO_2 or NO_x emissions.

Kentucky Power reiterated its position that DSM will diminish in a competitive environment. Kentucky Power expects the emphasis on DSM to shift from a societal perspective as reflected in the total resource cost test to the ratepayer perspective as reflected in the ratepayer impact measure test.

Kentucky Power stated that wholesale competition had not had an impact on its DSM programs and was not expected to have any impact in the future. Kentucky Power indicated it did not produce forecasts based on a wholesale and retail competitive environment but that anticipated increasing competition will reduce DSM levels because 1) cost-effectiveness would be judged from a shorter-term perspective and 2) the emphasis of the DSM evaluation would be from a ratepayer perspective rather than from a societal perspective.

On February 28, 2000, in Case No. 95-427, the Commission approved Kentucky Power's continuing DSM programs through 2002 and directed Kentucky Power to file, by no later than August 15, 2002, evaluations of its DSM programs and any requests to extend those programs beyond 2002. For that reason, staff makes no specific recommendations for Kentucky Power's next IRP filing beyond its earlier recommendation that Kentucky Power should address the six specific recommendations from DOE.

Section 4
SUPPLY-SIDE RESOURCE ASSESSMENT

INTRODUCTION

Kentucky Power owns and operates the 1,060 Megawatt, coal-powered Big Sandy Generating Station consisting of an 800 MW unit and a 260 MW unit. It has a Unit Power Agreement with AEP Generating Company to purchase 390 megawatts of capacity from the Rockport Generating Plant through the year 2004. The total generating capability for the AEP System is 23,759 MW, or 23,054 MW after adjusting for 705 MW of unit power sales.

AEP's major companies are interconnected by a high-capability transmission system consisting of an integrated 765-KV, 500-KV, 345-KV and 230-KV extra-high-voltage network, with an underlying 138-KV transmission network. This integrated system is centrally dispatched from the AEP System Control Center in Columbus, Ohio.

RESOURCE ASSESSMENT AND PLANNED ACQUISITION

At the time of filing Kentucky Power/AEP's 1999 IRP, there were no specific plans for new capacity additions on the AEP System. Kentucky Power indicated that when the time for commitment to specific capacity additions approached, all means of adding capacity, including self-build and external resource options, would be considered. Under this expansion plan, beginning in the year 2005, AEP would add 9,100 MW of new capacity through the year 2019 to maintain a reserve margin of 12 percent. Kentucky Power stated that the AEP System could require additional resources as early as 2003 with the high forecast, or as late as 2007 with the low forecast.

For the purposes of the 1999 IRP, the allocation of new capacity was determined based on the relative reserve margins of the AEP operating companies. This was accomplished by assigning each new capacity addition to the company or companies with the lowest reserve margin(s). Under that analysis, Kentucky Power's share of the capacity additions would be 1,100 MW starting with 300 MW to be added in the year 2005. However, commitments regarding ownership of new capacity had not been made at the time the IRP was filed and would not be made until new capacity was needed, and would take additional factors into account, including all pertinent circumstances existing at the time such decisions were made.

RELIABILITY ANALYSIS

The AEP System is planned, constructed, and operated as a single integrated power system; however, each company is responsible for providing adequate generating-capacity resources to supply its own requirements. A basic reliability principle of system planning is to maintain a reasonable balance among major system parameters, such as the size of the system load, the size of the largest generating plants, the strength of the transmission system, and the strength of interconnections with other power systems. For purposes of this IRP, Kentucky Power defined reliability as the degree to which the system is able to meet the power requirements of its customers on demand under both normal and abnormal conditions.

Reserve margin is the portion of capacity which exceeds demand. Continuity of supply can be assured only when the utility has sufficient supply-side resources to meet its customers' peak demands, plus an additional amount of reserve margin to provide for contingencies. These contingencies include:

1. Forced outages at generating units.
2. Reductions in generating unit capacity due to equipment failure or adverse operating conditions.
3. Reductions in electrical output due to transmission restrictions.
4. Reductions in generating unit capacity (or shutdown of units) due to actions by regulatory authorities; and
5. Load increases due to extreme weather conditions.

On the AEP System, the evaluation of reliability associated with capacity reserves involves developing the interrelation between daily peak load and available capacity for each day of the study period, taking into account scheduled maintenance requirements, capacity deratings, and contingencies such as forced outages. The concepts for evaluating a power system's installed reserves are reflected in AEP's Capacity Reserve Analysis (CRA) computer program. CRA simulates the operation of the AEP System for each hour of the study period and calculates the range of daily capacity margins likely to occur through that period.

A relationship exists between (1) system reliability level, (2) average system on-peak generating–unit availability, and (3) reserve margin. For planning purposes, estimates of AEP's reserve requirements are premised on the basis that, for nominal projected conditions, a marginal, but satisfactory, level of capacity-deficient days – days in which AEP would be seeking emergency assistance from other systems – should be no more than 5% to 10% (20 to 40) of the number of days in a year.

During the planning period, the AEP System projects its average system on-peak equivalent availability to attain 90% or better. Assuming an equivalent availability of 80% or better, a reliability level of 30 capacity-deficient days (the mid point of the 20 to 40 days previously cited), results in a required reserve margin of 8% or less. However, this would be insufficient to cover operating reserve requirements and certain outage requirements at the time of the annual peak demand. In order to provide for operating reserves plus the loss of the largest unit on the system, it is necessary for the AEP System to maintain a 12% reserve margin at the time of annual peak demand, excluding interruptible loads. Therefore, 12% has been used by AEP as an appropriate reserve margin for long-range resource planning studies.

SUPPLY-SIDE SCREENING AND ANALYSIS

Kentucky Power/AEP evaluated several different types of capacity and several different types of generation technology. Those included:

1. Baseload Capacity
   a. Pulverized coal with flue gas desulfurization
   b. Coal gasification combined cycle (CGCC) units
   c. Nuclear w/advanced pressurized water reactor (APWR)

2. Intermediate Capacity
   a. Gas-fired combined cycle
   b. Fuel cells – molten carbonate (MCFC)

3. Peaking Capacity
   a. Gas-fired combustion turbines
   b. Advanced battery energy storage

4. Intermittent Capacity
   a. Conventional hydroelectric
   b. Wind turbine farm
   c. Solar photovoltaic

For the purposes of developing its IRP rather than conducting detailed screening analyses (as was previously done) and essentially speculating as to the specific type, size, or means of acquisition of future individual generation resources, the company deemed it appropriate to consider these future resources on a generic, "undesignated," basis and to report them in terms of the aggregate MW of resources required (in multiples of 100 MW) for each of the forecasted years affected.

At the time of filing the IRP, the AEP System had less than 1 MW of non-utility generation available to it; however, it had committed to purchasing power from Summersville Hydro, a PURPA qualifying facility, beginning in January 2001 in amounts ranging from 17 MW during the summer to 25 MW during the winter.

AEP's base case resource expansion plan included the addition of 9,100 MW in new capacity over the period from 2005 through 2019 to maintain a reserve margin of about 12% of the total firm load obligation. This amount of new generation resources takes into account the assumed retirement, for study purposes only, of certain generating units that will have reached 50-70 years of service life.

ATTORNEY GENERAL'S COMMENTS

The Attorney General expressed concern about several supply-side resource issues. First, the AG mentioned the significance of the potential loss of the Rockport capacity in January 2005 and recommended that Kentucky Power should begin to explore a renewal of the lease with Indiana and Michigan Power. Secondly, the AG urged both Kentucky Power and the Commission to monitor several items that may affect the timing and nature of capacity additions potentially needed by the AEP System. These items were load growth, the effects of deregulation in those states in which the AEP sister companies operate, and potential availability of power from the Ohio Valley Electric Corporation (OVEC), which is partially owned by AEP. Thirdly, the AG criticized Kentucky Power for its "inadequate job of including the impact of pending environmental regulations, including Global Climate Change and NOx emissions," and urged the Company to include contingency costs for future CO_2 emissions in order to give renewable energy options proper financial weighting in the IRP.

In its reply comments, Kentucky Power contended that several of the AG's observations, including its conclusions regarding load growth and the potential implications of the Rockport agreement's expiration, were based on a misunderstanding and misreading of the underlying data. Kentucky Power also reiterated that there are currently no specific plans beyond 2001 for new generation resources on the AEP System, that all means for addition of new resources will be considered when appropriate, and that the planning process is a continuous activity such that the resource expansion plan presented in the IRP is subject to change.

Relative to the availability of OVEC power, the Company responded that it has very closely monitored the contractual and operational developments of the Portsmouth (Ohio) Gaseous Diffusion Plant, whose potential closing would free up capacity. While the Company indicated that it would certainly pursue such power if it becomes available, it also responded that it would be imprudent for the Company to base its planning on such a speculative scenario.

With respect to environmental issues, Kentucky Power stated that it would be premature, unnecessary, and inappropriate to include potential carbon taxes in the IRP report. The basis for this opposition was the Company's position that U.S. ratification of the Kyoto Protocal or enactment of laws to control greenhouse gas emissions is highly unlikely for the foreseeable future.

As events unfold over the next few years, the staff expects Kentucky Power/AEP to continue to closely monitor the availability of OVEC capacity from the Portsmouth Gaseous Diffusion Plant and, to the extent applicable, reflect such capacity in its planning process. Kentucky Power/AEP should also be more forward-thinking in its planning with respect to potential NOx and CO_2 requirements.

DISCUSSION OF REASONABLENESS

In its report on Kentucky Power's 1996 IRP, Staff made the following recommendations:

- Kentucky Power/AEP should continue to expand the list of options screened.

- Kentucky Power/AEP should screen purchased power in the same manner as other supply-side alternatives.
- Kentucky Power/AEP should fully consider the potential effects of environmental considerations, especially NOx requirements and CO_2 concerns, in its supply-side analysis and should thoroughly document its analysis of these issues.

Kentucky Power/AEP did not expand the list of options screened and stated that, absent specific information regarding potential purchases from other utilities, purchased power was not selected as an option for this expansion. Likewise, Kentucky Power/AEP opted not to give full consideration to the potential effects of the environmental considerations previously recommended.

Staff is not satisfied with Kentucky Power/AEP's responses to the recommendations included in the report on its 1996 IRP. We recognize that industry restructuring is underway in Ohio, where other AEP companies operate. We also recognize that the AEP-CSW merger recently received final approval from the Securities and Exchange Commission. While change is occurring, this does not free Kentucky Power from its responsibility to plan for the needs of its customers and to be responsive to the concerns of the regulators to which it reports. For these reasons, staff reiterates its previous recommendations on Kentucky Power's supply-side screening as set out in the report on Kentucky Power's 1996 IRP.

Section 5
INTEGRATION

INTRODUCTION

After development of the load forecast, resource requirements determination, and identification and screening of both supply-side and demand-side options, the next step in the IRP process is the integration of supply-side and demand-side options. This step involves the development of an integrated resource expansion plan reflecting the implementation of expanded DSM programs in various jurisdictions across the AEP System.

These expanded DSM impacts represent the amount by which the base load forecast was reduced in order to determine the resulting adjusted internal demand. For the AEP System, the estimated reduction in its base peak internal demand about midway through the forecast period (i.e., The winter of 2009-2010) due to expanded DSM programs is 60 MW. For Kentucky Power, the estimated reduction due to expanded DSM is 5 MW for that same period. Beyond 2014, such impacts decrease based on the assumption that there will be no new DSM conservation program participants after 2004, which would result in no replacements of the DSM measures at the end of their service lives. By the year 2019, this results in the total expanded DSM impacts on winter-season demand and annual energy being reduced to levels of 30 MW and 32 GWh, respectively. For Kentucky Power, the corresponding reduced total DSM impacts would be 2 MW and 3 GWh.

RESOURCE PLAN RESULTS

Under the resulting resource plan, starting in year 2005, the AEP System could require up to about 9,100 MW of new generating capacity through 2019. To allocate blocks of resource additions equitably, each successive resource block was generally assigned to the operating company or combination of operating companies with the lowest reserve margin. As a result, Kentucky Power was assigned 1,100 MW of new resource additions through the year 2019.

The AEP System integrated resource plan's reliability is based on several assumptions, including load growth projections averaging 1.4% per year and an AEP System average equivalent generating unit availability of 80% or greater. The projected number of capacity-deficient days on the AEP System is not expected to exceed about 10 days per year, which reflects the addition of new units commencing in the year 2005.

UNCERTAINTY ANALYSIS

The Company's long-term resource expansion reflects, to a large extent, assumptions that are subject to change. Some key factors that affect the timing of future capacity additions are the magnitude of future loads and capacity reserve requirements. The magnitude of the future load in any particular year is a function of load growth and DSM impacts, while capacity reserve requirements could vary depending on the desired reliability level and average system generating-unit availability.

To examine the impact that the uncertainty of some of the parameters had on the timing of new capacity on the AEP System, a sensitivity analysis was conducted in which the effects of variations in load growth were evaluated. Taking into account possible variations in the parameter values, additional resources could be required as early as 2003 in the high forecast or as late as 2007 in the low forecast. With a 12% minimum reserve criterion, the primary determinant for the year of first generation resource additions is the load forecast.

The results of sensitivity analyses demonstrate that changes in assumptions regarding key parameters could result in significant changes in the IRP expansion. Developments with respect to these parameters are monitored, to reduce uncertainty where possible. In addition, contingency plans to meet scenarios based on alternate assumptions are explored, to ensure that the expansion is flexible enough to be adaptable to meet changes in future circumstances.

ENVIRONMENTAL COMPLIANCE

The AEP System's strategy for meeting the Title IV air emission requirements of the Clear Air Act Amendments of 1990 includes the continual evaluation of alternative fuel strategies, opportunities to purchase sulfur dioxide (SO_2) allowances, and possible post-combustion technologies in order to lower the overall cost of compliance. Its plan anticipates the continued use of scrubbers at Ohio Power's Gavin Plant, the continued use of low-sulfur coal over much of the system, the use of the Phase I accumulated SO_2 allowance bank, and the switching to lower-sulfur fuels when economical. In addition, both units of the Big Sandy Plant have already been equipped with low-NOx burners, so no significant changes in fuel supply are anticipated at that plant.

DISCUSSION OF REASONABLENESS

Staff is generally of the opinion that Kentucky Power/AEP's methodology in determining the integrated plan is sound. However, as was noted in a previous section of this report, the Attorney General criticized Kentucky Power's IRP for a perceived failure to adequately include environmental impacts. Staff was critical in this area and also of Kentucky Power/AEP's failure to expand the number of supply-side options screened, including purchased power options. While the methodology is sound, the results are limited by the shortcomings in Kentucky Power/AEP's supply-side analysis. Staff recommends that Kentucky Power/AEP follow the same integration methodology in its next IRP, but with a broader view of supply-side options including potential environmental costs.

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
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FRANKFORT, KY. 40602
(502) 564-3940

May 31, 2000

To: All parties of record

RE: Case No. 1999-437

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING REPORT OF KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER TO THE KENTUCKY PUBLIC SERVICE COMMISSION, OCTOBER, 1999	)))))	CASE NO. 99-437

O R D E R

The Commission, having considered the motion of the Kentucky Division of Energy to modify the procedural schedule to allow for the filing of the additional comments tendered with its motion, the objection by Kentucky Power Company and finding good cause, HEREBY ORDERS that the motion is granted and the tendered additional comments are accepted for filing.

Done at Frankfort, Kentucky, this 31st day of May, 2000.

By the Commission

ATTEST:

Executive Director

RECEIVED

MAY 2 5 2000

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING)
REPORT OF THE KENTUCKY POWER)
COMPANY D/B/A AMERICAN ELECTRIC) CASE NO. 99-437
POWER TO THE KENTUCKY PUBLIC)
SERVICE COMMISSION, OCTOBER 1999)

**OPPOSITION OF
KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER
TO THE MOTION FOR AN AMENDMENT TO
THE PROCEDURAL SCHEDULE TO AUTHORIZE THE
KENTUCKY DIVISION OF ENERGY TO FILE
REPLY COMMENTS**

Kentucky Power Company d/b/a American Electric Power ("AEP") hereby objects to the Natural Resources and Environmental Protection Cabinet, Division of Energy's "Motion for an Amendment to the Procedural Schedule to Authorize the Kentucky Division of Energy to File Reply Comments." The proposed Reply Comments add no new information to this proceeding; rather, they reiterate the position previously stated by the Division of Energy. Moreover, many of the concerns and comments of the Division are more appropriately addressed at the KPCo DSM Collaborative than in this proceeding. The original procedural schedule gave all parties, including the Division of Energy, adequate opportunity to state their positions in writing and make them part of the record. The Division took full advantage of that opportunity and filed an extensive memorandum after having fully participated in the data requests and the informal conference. It has shown no good cause to further prolong this proceeding beyond the original procedural schedule. Accordingly, Kentucky Power Company requests that the Division's motion be denied.

Respectfully submitted,

Judith A. Villines

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CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing Opposition of Kentucky Power Company d/b/a American Electric Power's the Motion for an Amendment to the Procedural Schedule to Authorize the Kentucky Division of Energy to File Reply Comments was served by United States first class mail, postage prepaid, upon:

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This the 25th day of May, 2000.

Judith A. Villines

Judith A. Villines

KE057:KE137:3949:FRANKFORT

RECEIVED

MAY 05 2000

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING REPORT OF THE KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER TO THE KENTUCKY PUBLIC SERVICE COMMISSION, OCTOBER, 1999	)))))	**CASE NO. 99-437**

MOTION FOR AN AMENDMENT TO THE PROCEDURAL SCHEDULE TO AUTHORIZE THE KENTUCKY DIVISION OF ENERGY TO FILE REPLY COMMENTS AND THE REPLY COMMENTS

Comes the Natural Resources and Environmental Protection Cabinet, Division of Energy, Intervenor herein, and moves for an amendment to the procedural schedule in Case No. 99-437, to permit KDOE to file additional comments to clarify issues raised in the "Reply Comments of Kentucky Power Company on the Comments of the Office of Attorney General of the Commonwealth of Kentucky and of the Kentucky Division of Energy," dated April 17, 2000. If this motion is granted, KDOE respectfully offers the following comments for inclusion in the case record. The sequence of our comments generally follows that of KPCo's 4/17/00 filing.

1. **Market Barriers**

KDOE concurs with KPCo's statement that the "massive market failure" identified by E Source cannot be solved by any one entity alone.[1] We suggested a market transformation approach, which depends for its success on the cooperative involvement

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[1] Reply Comments of KPCo, 4/17/00, p.11.

of a wide range of participants, including those referenced in KPCo's reply comments. Because of its close and ongoing business relationships with commercial customers and its extensive knowledge of electric power systems, the utility company can be a very valuable participant in market transformation efforts and can play a leadership role. Alternatively, it can take a passive role or even decline to participate, thereby reducing the effectiveness of the overall effort. We suggest that AEP/ KPCo assign staff to work with other interested parties, including KDOE, to investigate and estimate the efficiency gains potentially available in the new commercial construction market and to develop market transformation strategies aimed at correcting the massive market failure to whatever degree is feasible.

2. Adequacy of KPCo's Integrated Resource Plan

In regard to the 6-step IRP process, KDOE maintains that steps 3, 4 and 5 were not effectively performed. KPCo states that because of uncertainty in the electric utility industry, it did not believe it was appropriate to "speculate" about future specific supply-side or demand-side options. The future is inherently uncertain, and any analytical activity that relates to the future can be called "speculation." In our view, however, the IRP process requires a utility to analyze, compare the relative merits of, and integrate specific supply-side and demand-side options on a quantitative basis. If "little or no DSM information directly applicable to AEP or KPCo is available,"[2] we believe that part of the task of integrated resource planning is to analyze a range of options and develop such information. To call such an analysis "speculation" does not negate KPCo's

[2] Reply Comments of KPCo, 4/17/00, p.14.

responsibility to perform it. By relying on "undesignated blocks of resource additions," KPCo in effect is saying that the company will definitely meet future resource requirements – somehow or other.

KDOE stands corrected in regard to overlooking the embedded DSM energy impact of 37 GWh in 1998 and subsequent years. We still feel, however, that the quantity of new demand-side resources projected to be added in future years is token at best, when compared to the potential efficiency gains available in KPCo's service area.

KPCo implies that the Collaborative's ongoing Commercial SMART Audit and SMART Incentive programs, operated at current or slightly expanded levels, can capture at least as much efficiency improvements as "new programs that have not been tested in the Company's service area."[3] Although these existing programs are beneficial and serve as a useful first step, KDOE notes that the bulk of the activity has been directed to the retrofit of existing commercial buildings and concentrates on lighting retrofits. In cases where new buildings are involved, a whole-system approach to design has not, to our knowledge, been taken. Rather, customers have been persuaded to substitute certain types of energy-efficient fixtures and equipment for standard equipment at a relatively late stage in the design and construction process.

KDOE believes that major, long-lasting reductions in demand and energy use could be obtained through a whole-system approach that reaches the designers much earlier in the process and influences more than their choice of fixtures. It may help to use some numbers to illustrate our point. KDOE guesses that the SMART Audit and

[3] Reply Comments of KPCo, 4/17/00, p.20.

SMART Incentive programs, as presently administered, may reduce the total energy use of a new commercial building by 15%. Analyses by E Source and the U.S. Department of Energy, however, suggest that a whole-building approach to design could reduce energy use by at least 75%, at an affordable capital cost. We consider the 60-plus percentage points of potential savings that the existing DSM programs leave unharvested to be a major lost opportunity, because that building may operate for decades and would be difficult to retrofit later in a cost-effective way.

KPCo seems to be assigning all responsibility for new DSM program development to the DSM Collaborative.[4] If the existence of the Collaborative absolves the company from investigating, analyzing and developing new DSM programs, KDOE believes it would be better not to have a Collaborative at all. Its main function over the past five years – monitoring existing programs – could be performed adequately by KPCo and AEP staff.

KDOE is willing to continue trying to interest the Collaborative in new DSM program ideas. We must note, however, that any voting member can block the implementation, development, or even in-depth consideration of new DSM programs. Further, while the Collaborative appears capable of monitoring ongoing programs, its non-utility members presently have little more technical expertise in developing new market transformation programs than any other group of community members. If KPCo is serious about exploring the opportunities – which we believe to be very large – it will

[4]Reply Comments of KPCo, 4/17/00, pp. 19-20.

allocate resources to analyzing them in some detail. This may require contracting with experts outside the company.

In regard to industrial DSM programs, KDOE believes that due to market barriers similar to those cited in the commercial sector (plus certain additional ones), industrial customers are missing huge opportunities for cost-effective energy savings and demand reductions. It should be possible to develop market transformation programs that are appealing enough to induce large industrial companies not to opt out of the DSM program.

In regard to the benefit/cost tests, KDOE is aware of the potential "stranded cost" problem and addressed it on page 9 of our original comments. KDOE supports the use of all four standard cost effectiveness tests, but believes that the TRC test is a good indicator of where large potential savings may exist in the energy services market. We also believe that the basic purpose of integrated resource planning is to minimize the total resource costs of providing energy services. Another good indicator of market potential is a present value life-cycle analysis of a design method or technology from the perspective of the customer.

3. Market Transformation

KDOE was pleased to learn about the existence of Datapult Energy Information Services and the "Learning from Light" education program, and supports their continued development.

The main purpose of our analysis was to outline some potentially huge business opportunities in the areas of improved end-use efficiency and distributed generation that

KPCo/AEP may wish to consider. If one particular company is not interested in exploring the full range of market opportunities which we believe exist, other competing companies will eventually find ways to profit by more effectively serving the market for value-producing energy services.

VERIFICATION

I, Geoffrey M. Young, state that I have written the above document and that to the best of my knowledge and belief all statements and allegations contained therein are true and correct.

Geoffrey M. Young

Geoffrey M. Young, Assistant Director
Division of Energy
Department for Natural Resources

Subscribed and sworn to before me by Geoffrey M. Young, this the 5th day of May, 2000.

Jean A. Cook

NOTARY PUBLIC

My Commission Expires: 1/10/2002.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing MOTION FOR AN AMENDMENT TO THE PROCEDURAL SCHEDULE TO AUTHORIZE THE KENTUCKY DIVISION OF ENERGY TO FILE REPLY COMMENTS AND THE REPLY COMMENTS was mailed, first class, postage prepaid, the 5th day of May, 2000, to the following:

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PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING	)	
REPORT OF KENTUCKY POWER COMPANY	)	CASE NO. 99-437
D/B/A AMERICAN ELECTRIC POWER COMPANY	)	

REPLY COMMENTS OF KENTUCKY POWER COMPANY ON THE COMMENTS OF THE OFFICE OF ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY AND OF THE KENTUCKY DIVISION OF ENERGY

INTRODUCTION

Kentucky Power Company ("KPCo" or "Company") submits these reply comments, prepared by the witnesses of record and transmitted through counsel, in response to the comments filed in this proceeding by the Office of the Attorney General of the Commonwealth of Kentucky (AG) on March 29, 2000, and by the Kentucky Division of Energy (KDOE) on March 31, 2000. KPCo appreciates the opportunity to provide responses to the many comments from the AG and the KDOE and shares their concerns on various issues raised in this proceeding. In formulating this response, the Company has attempted to briefly and fairly interpret the comments of both the AG and the KDOE. However, failure by the Company to comment on a particular position or view of either the AG or the KDOE should not be taken as an endorsement of that particular position or view.

Both the AG's and the KDOE's comments raise issues with respect to the Company's 1999 integrated resource plan, alleging that the Company has not given those issues adequate or proper consideration or treatment. The Company believes, however, that the information provided in the Company's 1999 Integrated Resource Planning ("IRP") Report is appropriate, given the changing nature of the electric utility industry, the move toward increasing competition and industry restructuring. In this regard, some of the specific concerns raised by the AG and the KDOE are addressed in the reply comments that follow. These comments are categorized in the following order:

A. Load Growth

B. Supply-side Resources

C. Environmental Issues

D. Demand-Side Management

A. LOAD GROWTH

The AG notes on page 3 of its comments that KPCo's projected annual load growth of about 2% per year "appears to be high" and "seems likely" to be "not realistic," because: (1) KPCo's load growth failed to meet the projections contained in its 1996 IRP Report, (2) the weather-corrected load appears to be flat in recent years, (3) weather-corrected loads experienced in 1999 were significantly below those projected in the 1999 IRP Report, and (4) load growth has been flat during a period of economic boom. As a result, the AG suggests, the need for generating capacity will be postponed.

The AG's superficial analysis of KPCo's load growth does not comport with the facts. To begin with, KPCo's total internal energy requirements are forecasted to grow at an average annual rate of 1.7% over the 1999-2019 period (IRP Report, page 1-6). In comparison, during the 1994-98 period, such requirements grew at an average annual rate of 1.9%, or 2.1% on a weather-normalized basis (based on data shown on Exhibit 2-30 of the IRP Report). Also, if information for year 1999 is considered (as provided by the Company in response to AG Request No. 6, First Set of Data Requests), energy requirements grew at an average annual rate of 1.9%, or 1.8% weather-normalized. Based on such historical trends, it can not be concluded, as the AG suggests, that the forecast is "high" or "unrealistic." Rather, the projected rate of growth of energy requirements is reasonable.

Similarly, using the same references as above, KPCo's summer peak internal demand is projected to increase at an average annual rate of 1.6% over the forecast period. Over the 1994-98 period, such demand grew at a rate of 3.0%, or 3.7% weather-normalized. If the 1999 experience is included in the analysis, the growth rate was 2.4%, or 1.6% weather-normalized. Again, based on these historical trends, rather than being "high" or "unrealistic," the forecast can be characterized as being reasonable.

Also, winter peak internal demand is projected to grow at an average annual rate of 1.8% over the forecast period. From 1994/95 to 1998/99, such demand grew at a rate of 1.2%, or 0.5% weather-normalized. However, on January 27, 2000, the Company experienced a new all-time peak internal demand of 1,558 MW (which is also the weather-normalized value). It is worth noting that this demand exceeded not only the peak demand forecasted for the 1999/2000 winter season (1,486 MW), it also exceeded the forecast for the winter of 2002/03 (1,533 MW). This experience refutes the AG's suggestion that the Company has overforecasted its annual peak demands in recent years. Thus, based on this latest information, from 1994/95 to 1999/2000, KPCo's winter peak internal demand grew at an average annual rate of 2.7%, or 2.1% weather-normalized. Again, in light of such historical trends, the forecast is neither "high" nor "unrealistic." Instead, it is reasonable.

From the above discussion, it is obvious that the AG's conclusions regarding KPCo's load growth are based on a misunderstanding and misreading of the underlying load data. Such conclusions are therefore unwarranted.

B. SUPPLY-SIDE RESOURCES

On page 2 of its comments, the AG states that the biggest issue facing KPCo in the near future is the loss of Rockport capacity in January 2005, which will cause KPCo to become extremely capacity deficient with respect to AEP System. As a result, KPCo "will be assigned 300 MW out of the 500 MW of additions scheduled for the entire AEP System in 2005." The AG also states that "the 300 MW for the KPCo system constitutes an increase in capacity of 30%. The rate implications for Kentucky ratepayers are significant." Thus, according to the AG, KPCo customers would "become at risk of large rate increases to cover the cost of capacity additions." (AG Comments, page 3.)

Furthermore, the AG suggests, on page 2 of its comments, that the Company "needs to begin now to evaluate its options, the most obvious of which is to explore a renewal of the lease [beyond 2004] with Indiana and Michigan (I&M) for the Rockport capacity, [inasmuch as] the lease has already been extended for the 5-year period between 2000 and 2004." The AG also recommends that KPCo initiate a conversation with I&M about extending the lease "before this capacity is committed to another utility."

With respect to the above comments, several observations can be made. First, the AG's assertion that the KPCo system capacity would increase by 30% in 2005 as a result of the addition of 300 MW is both misleading and incorrect. KPCo's system capacity in 2004 would be 1,450 MW, which includes both the Big Sandy Plant (1,060 MW) <u>and</u> the Rockport unit power purchase (390 MW). In 2005, assuming that the purchase expires and that a new 300-

MW resource is added, KPCo's system capacity would then be 1,360 MW. Thus, instead of having the KPCo system capacity increase by 30% (based on relating the 300-MW addition to the 1,060-MW Big Sandy plant, as the AG incorrectly did), the system capacity would actually decrease by 90 MW (i.e., 1,450 MW less 1,360 MW). To put it another way, the 300-MW addition (and its associated costs) would simply replace the 390-MW purchase (and its associated costs). The resulting rate implications would, therefore, be much different from what the AG implies.

Secondly, the AG mistakenly assumes that new generation resources are, indeed, firmly scheduled for 2005 and that the Company should, therefore, begin now to evaluate its options with respect to such resources, focusing particularly on simply extending the lease, since it was, after all, extended previously. In this regard, it is important to understand that the provision for extending the lease 5 years beyond 1999, i.e., through 2005, was incorporated into the original lease agreement, and that no provision was made for further lease extensions.

With regard to the firmness of new generation resource additions "scheduled" for the future, it is important to keep in mind that, as noted on page 1-9 of the IRP Report, there are currently no specific plans beyond 2001 for new generation resources on the AEP System. Size, technology type, ownership (among AEP operating companies) or means of acquisition, and precise timing of subsequent future generation resource additions on the AEP System have not yet been determined. When the time for commitment to specific generation resource additions approaches, all means for adding such resources, including self-build and external resource options, will be considered. In this regard, as stated on page 1-1 of the IRP Report, the planning process is a continuous activity; assumptions and plans (both short-term and long-term) are being continually reviewed as new information becomes available, and are modified as appropriate.

The resource expansion plan presented in the IRP Report reflects, to a large extent, assumptions that are subject to change. It is not a commitment to a specific course of action, since the future is highly uncertain, particularly in light of the move to increasing competition among suppliers in the marketplace and restructuring in the industry.

On the matter of capacity additions that will be needed in the future for the AEP System, the AG suggests that both KPCo and the Commission keep an eye on a number of items that may affect the timing and nature of such additions. In this regard, on pages 3-5 of the AG's comments, three items are suggested and discussed, namely: (1) load growth, (2) the effect of deregulation and (3) the availability of OVEC power.

With respect to the first item, load growth, along with its assertions on KPCo's load growth, as commented on above, the AG makes the general statement that "if load growth is less than projected, the need for generating capacity will be postponed." This, of course, states the obvious, assuming that the reduction in system load growth is significant enough to begin with, and that all other factors affecting the need for capacity remain unchanged.

With respect to the second item, the effect of deregulation, the AG observes that changes may occur in the load and capacity situation on the AEP System as a result of deregulation in those states in which the AEP sister companies operate, and concludes that "while it is too early to understand what effects deregulation in Ohio and other states will have on KPCo through the Intersystem Agreement, developments should be tracked closely." The Company has no quarrel with the AG on this matter. As already mentioned above, AEP/KPCo's planning process is a continuous activity. As new information becomes available, assumptions and plans are reviewed and modified as appropriate.

With respect to the third item, the availability of OVEC power, discussed on pages 4-5 of the AG's comments, the AG notes that financial problems associated with the uranium enrichment process could lead to a shutdown of the Portsmouth Gaseous Diffusion Plant, which is served by OVEC. The AG notes that "this possibility was not included in the IRP as a way to meet future capacity needs," and that "AEP should begin now to explore how existing contracts can be used or modified to assure that its low cost OVEC capacity will become available if the Portsmouth plant is closed."

As a major participant in OVEC, AEP has very closely monitored the contractual and operational developments of the Portsmouth facility. However, at this time, such a scenario is still speculative, and it would be imprudent for the Company to base its planning on such speculation. If, however, OVEC power does become available, AEP would certainly pursue its acquisition. In any event, AEP's current resource plan contains enough flexibility to adjust for the addition of such capacity.

C. ENVIRONMENTAL ISSUES

The AG's comments pertaining to the global climate change issue (beginning on page 6) contains some misunderstandings about AEP's voluntary program to reduce, avoid or sequester greenhouse gas emissions and the status of international negotiations to mandate legally-binding controls on such emissions.

In February 1995, AEP entered into a Participation Accord with the U.S. Department of Energy under the Climate Challenge Program. AEP pledged to undertake a broad array of supply-side and demand-side energy efficiency projects, tree planting and enhanced forest carbon management and other initiatives with the goal of avoiding and sequestering 9.5 million tons of carbon dioxide emissions by 2000. Contrary to the AG's understanding, AEP did not agree to reduce carbon dioxide emissions to 1990 levels, and the Company has been quite forthright in reporting the increase in emissions associated with rising electricity sales. It is true that if the Kyoto Protocol is ratified by the United States and enters into force, and the Congress passes implementation legislation mandating emission reductions on the Company, the burden of meeting the emission reduction target and timetable contained within the Protocol would be enormously challenging and costly to the Company. While it would be the Company's intention to rely extensively on the purchasing of "assigned amount units," "certified emission reductions" and "emission reduction units," as permitted under the Protocol, any actions to reduce emissions from Company operations would likely necessitate the retirement and replacement of existing coal-fired generation with natural gas generation.

The AG's comments also contain illustrations of the impact on the Company of a $50/ton carbon tax and suggest that costs in the magnitude indicated should be included in the Company's IRP Report. The Company believes that this would be premature, unnecessary and inappropriate. It is highly unlikely that the U.S. will ratify the Kyoto Protocol or enact laws to control greenhouse gas emissions for the foreseeable future. There is substantial political opposition to the Protocol. Even the President has indicated the treaty is unacceptable to the U.S. until it has been amended to include emission limitation commitments from developing countries, and also until the rules and procedures associated with implementing the Kyoto Protocol flexibility mechanisms are established to the satisfaction of the U.S. In addition, there is a need for effective compliance enforcement provisions. The Protocol cannot be amended until it enters into force, and entry into force is doubtful in the absence of U.S. ratification. Consequently, it is likely that the relevant United Nations organizations will negotiate a supplemental treaty to accompany the Kyoto Protocol, or an entirely new instrument will be negotiated to meet the demands of the U.S. This will take several years. Therefore, it is highly speculative to conclude that the Company will face carbon taxes or emission controls in the near future. The Company accordingly believes that it is unnecessary to include the impact of such uncertain policies on the Company in its IRP reports.

D. DEMAND-SIDE MANAGEMENT

Demand-side management (DSM) issues are addressed in, and are the major focus of, the KDOE's comments, which are organized in five sections. Section I, the Introduction (page 1), presents the purpose of the comments, which is "to outline a comprehensive alternative" to the integrated resource plan presented in KPCo's 1999 IRP Report. According to the KDOE, "this alternative is in closer agreement with the rationale that underlies integrated resource planning."

In Section II of its comments (pages 1-2), the KDOE presents its "vision of the future," which it sees as "a well-functioning [competitive] market for energy services." In Section III (pages 2-5), in contrast to the "competitive market scenario" of Section II, the KDOE discusses what it labels as "the present reality: pervasive and chronic market barriers," and includes a list of "some examples of chronic market failures in the new commercial construction market."

In Section IV (pages 6-10), the KDOE turns to a discussion of KPCo's 1999 integrated resource plan and essentially characterizes that plan as being inadequate, particularly with respect to DSM programs. Further, the KDOE asserts (bottom of page 9 to top of page 10) that the "strategy embodied in KPCo's IRP [Report] ... tends to lock KPCo into the role of a vender of commodity electricity, which is likely to become an extremely competitive business at some future time."

In Section V (pages 10-21), which is titled "An Alternative Scenario: Market Transformation," the KDOE states (on page 10) that "it is not too early for the company to initiate a comprehensive reexamination of its relationship to the market," and suggests that AEP's strategy should be "to refocus its perspective from being a vendor of electrons to an energy service company." The KDOE further suggests (on page 12) that AEP "initiate a number of programs and actions aimed at optimizing overall efficiency throughout the energy sector." In this regard, six initiatives are suggested for possible implementation: (1) establish an AEP-owned energy service company (ESCO), or form joint ventures with (or purchase) one or more existing ESCOs; (2) use Local Integrated Resource Planning (LIRP); (3) initiate a comprehensive program in new commercial construction; (4) promote cogeneration to gain thermal efficiencies; (5) promote distributed generation and green power through net metering; and (6) support statewide and regional market transformation initiatives.

The KDOE's comments raise a number of issues, which can be categorized into three general areas, namely: (1) Market barriers, (2) Adequacy of KPCo's integrated resource plan, and (3) Market Transformation. The Company's response to the KDOE's comments in each of these areas follows.

1. MarketBarriers

To begin with, the KDOE's "vision of the future" is essentially a portrayal of a utopian-like society in which people live and function in a perfectly competitive world. The Company would certainly concur with the KDOE's observation in Section III of its comments that such a scenario is far removed from reality. Market barriers and lost opportunities indeed exist today in the new commercial building construction market, as well as in the existing building market.

This matter is discussed in detail in the report entitled "Energy-Efficiency Buildings: Institutional Barriers and Opportunities," issued in 1992 by E-Source, Inc., and referenced on page 3 of the KDOE's comments.

Highlights of that E-Source report are presented in an article entitled "Institutional Inefficiency," by Amory Lovins, E-Source's principal technical consultant, and published in *IN CONTEXT #35*, Spring 1993, by the Context Institute. The article states that "the reasons for this massive market failure lie within the institutional framework that shapes how buildings are and have been financed, designed, constructed, commissioned, operated, maintained, leased, and occupied. Nearly all of the roughly two dozen actors who play a role in this process have perverse incentives that reward inefficient practice and penalize efficient practice." The article goes on to say that what is needed to fix these problems "is no less than reinventing the building design process, and with it, many current real-estate practices."

It is especially important to note, as reflected in the Amory Lovins article, and in the examples of chronic market failures listed in Section III of KDOE's comments, that the collective "massive market failure" problem is institutional in nature and can not be solved by any one entity alone, whether it be a utility, an ESCO, a government agency, building contractors, or any other directly involved organization or participant. As the article also points out, the "forces that created this dysfunction are legion," and include developers, lenders and their advisors, commercial appraisers, designers, architects, engineers, improperly sized mechanical and electrical equipment, poor building design, contractors operating on a fixed budget, and others.

Despite the enormity of the market failure problem, it should be recognized that actions have nevertheless been undertaken within various segments of our society to overcome barriers to a well-functioning competitive energy services market. The overall impact of such actions was acknowledged in a November 1994 report entitled "Moving From DSM To Value-Added Customer Services: A Framework For The Journey," by the Policy Topic Committee of the Association of Energy Services Professionals. As stated on page 2 of that report, "although buildings and energy-using equipment are not as efficient as they could be, they are significantly more efficient in the 1990's than they were in the late 1970's." This observation reflects the fact that some of the market barriers relative to the new commercial building construction market either have been, or are being, overcome and that the associated lost opportunities are being addressed. In this regard, some of the specific efforts undertaken by various segments in our society (i.e., government agencies, professional trade organizations and other groups), as well as by the Company, to address market barriers and related matters are discussed in the Company's response to KDOE Request No. 7, First Set. A copy of that response is attached herein as Exhibit A.

The KPCo DSM Collaborative's Commercial SMART Audit and SMART Incentive programs provide examples of the Company's own contribution to addressing some of the market barriers. Although these programs do not, and could not, eliminate all barriers to the incorporation of efficiency measures in new and existing buildings, they have succeeded in reaching the new and existing building market. In this regard, the SMART Audit Program has provided an effective mechanism to assist customers and/or developers in identifying energy conservation measures that can be implemented into their building design and operation. As of year-end 1999, since the inception of this program (in May 1996), 1,375 audits have been conducted in the KPCo service area.

The SMART Incentive Program has, likewise, been successful in reducing the financial barriers to the implementation of recommended energy conservation measures. As of year-end 1999, since the inception of this program, financial incentives have been provided to nearly 100 customers of existing and new buildings, resulting in cumulative energy savings estimated to aggregate about 4,430 MWh.

2. Adequacy of KPCo's Integrated Resource Plan

On page 6 of its comments, in discussing the 6-step IRP process presented in Chapter 4 of the IRP Report, the KDOE states that "other than the single demand-side option of interruptible loads, the IRP [Report] does not even consider the possibility of initiating significant new programs. It simply assumes that new generation will be the most effective way to meet all future resource needs (that are not covered by the interruptible load program)." Also, in the KDOE's view, "KPCo simply did not effectively perform step 3 [identification and screening of supply-side resource options], ... short-circuited step 4 by declining to analyze any potential new DSM options or programs, and ... short-circuited step 5 [integration of demand-side and supply-side options] by declining to analyze [such] options on a consistent, quantitative basis." As a result, the KDOE concludes that the IRP Report "may not serve as an adequate basis for cost-effective future resource acquisition decisions," and that although the electric industry in Kentucky may someday be restructured, ... it is still regulated, ... and that resource plans should reflect the present reality."

Notwithstanding such aspersions cast by the KDOE on the integrity of the Company's IRP process, the Company has given -- and continues to give -- proper and appropriate consideration to the roles that both supply-side resources and DSM programs should, and do, play with respect to that process. The Company's resource plans do, in fact, reflect the "present reality," namely, that, as stated in the IRP Report (page 1-1), "the future, now more than ever before, is highly uncertain, particularly in light of the move to increasing competition among suppliers in the marketplace and restructuring in the industry." As a result (and as stated on page 1-2 of the IRP Report), "the traditional concepts of utility forecasting, planning and operation, along with traditional ways of conducting business, will likely change in the future. The impacts of such changes are not known at this time."

Therefore, in developing its current integrated resource plan, the Company did not believe it was appropriate to speculate as to the specifics of future supply-side resources. Such resources were, instead, treated as "undesignated" blocks of resource additions. Nor did the Company likewise speculate as to the specifics of possible DSM programs (such as suggested by the KDOE) for which little or no information directly applicable to AEP or KPCo is available. In this regard, only those DSM programs for which such information is available, including programs associated with the KPCo DSM Collaborative, were incorporated into the integrated resource plan.

It is also important, however, to understand that, although the undesignated blocks of resource additions might be assumed to represent supply-side resources, this assumption does not need to be exclusively limited to such resources. In a broader sense, these undesignated blocks of resource additions represent the combined impact of both supply-side resources and DSM programs that are yet to be specifically identified. Thus, if some new DSM programs with appropriate and sufficient supportable information, including load impacts, come into play and can be incorporated into the integrated resource plan, the system load forecast would then be reduced to reflect such DSM impacts. This load reduction would, in turn, reduce the system's reserve margin requirements, and thereby reduce the magnitude of the undesignated resources.

Along with unjustly criticizing the Company's IRP process, the KDOE also makes a number of misleading and incorrect assertions, thus raising several DSM-related issues. These issues include (a) DSM impacts: KPCo vs. other utilities; (b) DSM impacts: industry average vs. economically justifiable level; (c) Potential new DSM programs for KPCo; and (d) DSM evaluation: societal vs. ratepayer perspective. Comments on each of these issues follow.

(a) DSM impacts: KPCo vs. other utilities

On page 7 of its comments, the KDOE draws comparisons between the projected DSM energy impacts for KPCo for the period 2000-2014, as reported in the IRP Report, and the estimated average DSM energy impact reported for the nation's large electric utilities for the year 1998, as reported in a December 1999 publication by the U.S. Department of Energy's Energy Information Administration (EIA), entitled "Electric Power Annual 1998, Volume II" (or, more specifically, in the chapter entitled "Electric Utility Demand-Side Management," starting on page 73 of that report). In this regard, the KDOE characterizes KPCo's DSM programs as "token," stating that KPCo's projected DSM energy impacts for years 2000 (4 GWh) and 2004 (7 GWh) represent 0.05% and 0.09%, respectively, of KPCo's forecasted total internal energy requirements. In comparison, as the KDOE notes, the average DSM impact for large utilities in the U.S. in 1998 was 1.5% of sales to ultimate customers, or 16 to 30 times greater than the DSM impacts forecasted for KPCo.

The KDOE's characterization and comparison regarding KPCo's DSM programs are both inappropriate and misleading for several reasons. In the first place, the comparison does not cover a common time base. Any comparison between KPCo's DSM energy impacts estimated for the *future* and the estimated average DSM impact for the nation's large utilities for the *past* (1998 in this case) is inherently faulty, because of its apples-vs.-orange nature, especially in light of the ongoing move toward increasing competition among suppliers in the marketplace and restructuring in the electric utility industry. As the above-cited EIA report states (on page 75), "utility sponsored [DSM] programs and cost continue to be affected by changes within the electric utility industry," and (on page 73) "with the changes that are occurring within the electric utility industry, there is a great deal of uncertainty about the direction of utility sponsored DSM programs."

The EIA report does provide information that reveals trends already under way within the electric utility industry with respect to DSM programs. In this regard, the report indicates (on pages 79-80) that, for the period 1994-1998, annual DSM energy savings for the U.S. electric utility industry peaked in 1996; and from 1996 to 1998, such savings decreased by 20%. For the ECAR region, of which KPCo is a member, the comparable savings were even greater, amounting to 37%. Also, from 1994 to 1998, U.S. electric utility DSM costs decreased by 48%; and for the ECAR region, the comparable costs decreased by 79%.

This EIA-reported information reinforces the Company's belief, expressed on page 3-1 of the IRP Report, that the natural trend toward reduced DSM activity will continue in the future. However, it should be understood that this belief applies to the electric utility industry and is not meant to suggest that energy conservation and related DSM activities are decreasing from an overall societal perspective. The comparative responsibility for undertaking or sharing such activities has been effectively shifting, and will continue to shift, from electric utilities to other segments of society. The information provided in the attached Exhibit A reflects this phenomenon.

Secondly, the KDOE's DSM comparison is inappropriate and misleading because, in addition to not using a common time base, the comparison does not use a consistent base for DSM participants. As noted on Table 4, page 1-8 of the IRP Report, KPCo's future DSM impacts reflect only "expanded" DSM programs, i.e., program installations assumed to be made in the future; they do not include the impacts of "embedded" DSM programs, i.e., program installations already in-place. On the other hand, the EIA-reported DSM energy impacts for a given past year reflect the effects caused by all in-place program participants in that year (as noted on Table 44, page 75, of that report).

A more appropriate basis for comparison would be to use both the year 1998 and total embedded DSM energy impact as the common parameters. In KPCo's case, as shown on Table 4, page 1-8, of the IRP Report, the embedded DSM energy impact for 1998 was 37 GWh. This translates to 0.53% of KPCo's 1998 internal energy requirements of 6,992 GWh, making KPCo's 1998 relative DSM energy impact significantly higher, by up to an order of magnitude, than the 0.05% or 0.09% figures quoted by the KDOE for years 2000 and 2004, respectively.

Another more appropriate basis for comparison is to relate KPCo's DSM impacts to the DSM impacts for the general geographical area in which KPCo serves, i.e., the ECAR region, rather than to the entire U.S. In this regard, it is of interest to note that, from the EIA report (Table 48, page 79), the 1998 DSM energy impact for the ECAR region was 2,311 GWh, or 0.44% of ECAR's 1998 energy consumption of about 530,000 GWh. In comparison, for 1998, KPCo's DSM energy impact of 0.53% was actually higher than for the ECAR region as a whole, and much closer to the U.S. industry average (1.5%) than asserted by the KDOE. In light of these comparisons, therefore, the KDOE's portrayal of KPCo's DSM programs as "token" is unwarranted.

(b) DSM Impacts: Industry Average vs. Economically Justifiable Level

On page 7 of its comments, the KDOE asserts, regarding DSM, that "the industry average is far below what is justifiable economically." However, the KDOE fails to provide any sound basis for determining what level of DSM is justifiable economically, and who or what agency or agencies are in a position to determine that level. From a utility's perspective, the cost-effectiveness of DSM is significantly affected by the price of electricity, which can vary considerably from one area of the country to the other, whether deregulation is in place or not. Additionally, reaching what the KDOE declares "is possible according to technical potential studies," [emphasis added] is quite different, and can be significantly higher, than what is possible on a market-potential basis. The market-potential perspective, rather than the technical-potential perspective, more appropriately takes into consideration energy efficiency measures that, in accordance with KRS 278.285 (1)(g), "are available, affordable, and useful to all customers."

The Company does agree with the KDOE that not all available efficiency gains have been reached. This, however, should not be construed to mean that utilities have not come reasonably close to this goal, nor that reaching this goal is the responsibility of the electric utility industry alone. As the information on Exhibit A clearly indicates, whatever the economically justifiable DSM level might be, that level will be influenced by the established Federal Energy Efficiency & Appliance Standards; state building codes; and energy efficiency information and practices promoted through local building, plumbing, electrical and HVAC contractors, professional trade organizations, public interest groups, utilities and energy services companies, along with the customer market. Thus, the KDOE's "vision of the future" reflects the cooperation of all these major players and others in order to reach that "higher energy-efficiency level." Such a scenario will, in fact, be market-driven, not utility-driven.

(c) Potential New DSM Programs

On page 8 of its comments, the KDOE asserts the following: "KPCo has not analyzed a wide range of potential new DSM programs and measures since 1994. The analyses that AEP/KPCo has conducted during the period from 1995 to 1999 have focused on refining and enhancing DSM programs that were already in existence in the KPCo service territory, or on identifying programs to be eliminated."

Such assertions are misleading and completely ignore the Company's responses to the data requests by the KDOE that relate to these assertions, i.e., Request Nos. 8, 9 and 12b, First Set, and Request No. 1, Second Set. As discussed in those responses, as well as in Chapter 3 (the DSM chapter) of the IRP Report, the KPCo DSM Collaborative determines the DSM programs to be implemented in KPCo, not just KPCo alone. Despite being a member (although nonvoting) of the Collaborative, the KDOE does a grave disservice to the Collaborative and its other members when it disregards the work of the Collaborative.

Notwithstanding the KDOE's erroneous views on this matter, the Company has analyzed both new and existing programs and measures throughout the time of the Collaborative's existence, beginning in 1995. However, regardless of number of programs or measures analyzed, the Collaborative's success should not be measured by that yardstick. A more meaningful measure is the ability to reach those customers who are in need of, or wanting to adopt, energy-efficiency measures in their everyday lifestyles and/or business climates.

It is important to understand that not all customers, including entire customer classes or customer segments, are willing to participate in utility-directed DSM programs. For example, a majority of KPCo's industrial customers chose to opt-out from participating in the Collaborative's DSM industrial programs, which resulted in a very small number of potential industrial customers available for DSM programs. This can be attributed to the fact that many industrial customers incorporate their own energy efficiency measures into their businesses in order to be more competitive in their environment. Nevertheless, the Collaborative is responsible for developing and offering DSM plans so as to provide programs that are in accordance with KRS 278.285, i.e., "are available, affordable and useful to all customers." In the final analysis, though, the customer market will determine who participates and who does not, and which DSM measures are useful and which are not.

It is also worth pointing out that, as stated in the Executive Summary of the KPCo Collaborative DSM Programs filed September 27, 1995, "the purpose of the Collaborative [is] to jointly develop a demand-side management plan for the company, including program designs, budgets, and cost recovery mechanisms in a manner consistent with KRS 278.285." The Collaborative has, in fact, accomplished that, and has requested approval from the Commission to continue this process through 2002. This will result in a total of seven years of implementing DSM programs to reach KPCo customers. Inasmuch as the Collaborative has developed a package of DSM programs that have been successful, expansion of such proven DSM programs can at least be just as successful, compared to new programs that have not been tested in the Company's service area.

Also, despite the KDOE's incorrect assertions on the matter, the analyses that AEP/KPCo conducted during the 1995-1999 period have not focused solely on refining and enhancing existing DSM programs. Such analyses were necessary, in any event, to evaluate to what extent changes could, or needed to, be made to maintain or enhance cost-effectiveness. Furthermore, new programs and measures were also included in the analyses. For those existing programs where decreased participation, decreased load impacts, and/or rising program costs occurred, so as to negate the program's cost-effectiveness, such programs were eliminated. As a result, budget funds were transferred to programs that were cost-effective. Again, as mentioned above, the determination of DSM programs to be implemented in KPCo's service territory is the joint responsibility (requiring joint cooperation and effort) of all the members of the KPCo DSM Collaborative. It is not the responsibility of a single entity.

The KDOE also complains, on page 8 of its comments, that the KDOE had proposed major new DSM initiatives at several Collaborative meetings, but that "most of these suggestions were politely but firmly rejected." According to the KDOE, such programs were rejected because "AEP has made a decision at the corporate level not to consider, propose, or institute any major new DSM programs."

The KDOE's views on this matter distort reality. The proposals that were suggested by the KDOE representative to the Collaborative are described in KDOE's comments as "major new initiatives in the areas of new commercial construction and industrial energy efficiency." More specifically, these proposals included: (1) targeting DSM measures to alleviate distribution circuit overloads, and (2) providing financing alternatives for commercial & industrial customers. Both of these issues were addressed at the Collaborative meetings, and justifiable reasons were provided for their rejection. The reasons addressed several issues, including (1) why targeting DSM measures to alleviate AEP's distribution circuit overloads may not be applicable or cost-effective, because of the inability of such measures to achieve sufficient load impacts to prevent or significantly delay distribution system upgrades, and (2) why the Company's Smart Financing Program was changed in 1996 to provide direct incentives, rather than to provide financing. With respect to this second issue, it is of interest to note that the 1992 E-Source report that was used as a primary source document for the KDOE's comments recommended that "direct incentives" be incorporated in new commercial building construction. In addition, as explained in the Company's response KDOE Request No. 9, First Set, new measures and program modifications have been reviewed by the Collaborative for inclusion in the Commercial SMART Financing Program.

(d) <u>DSM Evaluation: Societal Perspective vs. Ratepayer Perspective</u>

On page 9 of its comments, the KDOE expresses its belief that the TRC test, which reflects the "societal" perspective, is still the most appropriate benefit/cost test to use in integrated resource planning. This belief, however, is not appropriate in the real world.

This issue was addressed in the Company's responses to Commission Staff Request No. 23, First Set, and KDOE Request No. 10, First Set. In those responses, the Company notes that, in anticipation of deregulation, and industry restructuring, the emphasis of the DSM evaluation process has been shifted from a societal perspective, as reflected in the TRC test, to the ratepayer perspective, as reflected in the RIM test (which, unlike the TRC test, takes into account utility revenue loss resulting from DSM program implementation). A major problem associated with analyzing DSM programs on a societal basis under a deregulated environment is the potential loss of the long-term benefits that in many cases are not realized until many years (typically 15 to 20 years) after the start of program implementation. Simply put, once the customer is given the choice to select an energy supplier, the projected load impact benefits can be lost to the utility that initially implemented the DSM program. What the KDOE fails to realize is that these costs cannot be recovered without increasing rates, thereby, making the utility less competitive in a deregulated environment. The TRC test does not take that factor into consideration, whereas the RIM test does.

The shift from the societal to the ratepayer perspective reflects a trend in how utilities have generally been viewing DSM as the industry moves to a competitive retail environment. Even though this view is not solely that of AEP alone, the KDOE believes that AEP should be the exception and use the TRC test (to the exclusion of other tests) in the IRP process. However, the KDOE's comments do not directly explain why the TRC test should be used (despite saying, on page 8, "for reasons that are explained in Section V below."), and lacks any sound explanation for its position on this matter. Additionally, once deregulation fully takes place, it is not clear what form an "integrated resource plan" will take, or how it would be appropriately evaluated.

3. Market Transformation

The KDOE's conception of AEP as being simply "a vendor of electrons" is an incorrect and unjust portrayal of AEP's business. AEP has always been a provider of the most reliable and efficient power to its customers at the lowest cost possible, as well as a provider of cost-effective energy services. AEP is an efficiency-oriented company interested in providing maximum value to its customers. Numerous examples of conservation and load management programs (aside from DSM programs) conducted by AEP were described in KPCo's earlier IRP Reports to the

Commission (See chapter 4 of both the 1991 and 1993 IRP Reports). Some of these ongoing activities and previous accomplishments have included programs in the general areas of Customer Research Programs, Information Programs, Technical Assistance Programs, Field Tests, Pilot Programs, SMART Programs, Special Tariffs and the Green Lights Program.

In view of the move toward industry restructuring, deregulation and associated increasing competition, AEP has, in fact, initiated what KDOE calls "a comprehensive reexamination of its relationship to the market." Moreover, AEP believes that it is in a better position than an outside entity to determine the most appropriate customer-oriented programs and initiatives to be implemented in its service territory. As a result, AEP is now offering value-added customer services to its customers in preparation for the competitive environment. For example, Datapult Energy Information Services is a portfolio of services that gives commercial and industrial firms an affordable means to significantly reduce energy, maintenance and administrative costs. Datapult offers two main areas of services: (1) Datapult Energy Monitoring Services, which monitors electricity, gas and water use, temperature and other information, and is used to identify opportunities to reduce energy and maintenance costs; and (2) Datapult Billing Services, which manages the customer's various utility bills and consolidates them into one statement, and can reduce accounting transaction costs.

Another Datapult service, Datapult In Education, provides money-saving energy monitoring and conservation services to secondary and elementary schools. This service also offers students and faculty Internet-access to the school's energy-use information in a simple graphical format for educational purposes.

AEP's Internet web site also provides educational information for customers on various topics. Examples of such topics are: (1) "Residential Information and Tips," which includes information on saving energy and electrical safety, and posts the most recent "Consumer Circuit" bill-insert information (referenced in Exhibit A); (2) "Geothermal Heating and Cooling," which provides information on the geothermal concept, how it works and its use; (3) "Customer Choice," which provides an overview of what customer choice is, state plans and activities, and service provider information; and (4) "Educational Programs," which is provided for schools, students, educators, and parents, and which includes information on teacher workshops that offer graduate credit.

AEP also has an environmental education program called "Learning From Light." Under this program, which is the first of its kind, AEP works with schools in which solar panels have been installed, to help those schools track their energy usage, and to educate students about solar energy. AEP assists those schools in monitoring the electricity that is generated from the solar panels. The amount of energy saved is determined through the use of the Datapult Energy Monitoring System. Two examples of the application of this program are the Bluffsview Project, located at the Bluffsview Elementary School in Worthington, Ohio, and the Abilene Project, located at Abilene Christian University in Abilene, Texas.

In summary, while KPCo appreciates the KDOE's enthusiasm for and interest in DSM measures, the KDOE comments do not give adequate and accurate consideration to KPCo's ongoing efforts in this area or to the real world barriers and factors that come into play. Accordingly, the KDOE"s comments are without merit in the context of KPCo's integrated resource planning report.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a true and exact copy of the foregoing Reply to Comments was served by first class mail, postage prepaid, upon:

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On this the 17th day of April, 2000.

Judith A. Villines

Judith A. Villines

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Request for Information, First Set
Dated December 20, 1999

Request No. 7:

On page 3-2, the IRP notes, "Increasing appliance efficiency standards and years of consumer educational programs will make energy efficiency the normal practice in the future." A similar statement is made on page 3-5.

a. Please describe the scope of these customer education programs, as well as any estimates that KPCo may have made of their impacts on customers' behavior and on energy use.

b. Does KPCo believe that the normal operation of market forces (i.e., Adam Smith's "Invisible Hand") will cause customers to implement all energy efficiency measures that are cost effective?

c. Does KPCo believe that there are significant barriers that act to prevent customers from implementing all the energy efficiency measures that would be cost effective?

Response:

To begin with, the statement referenced on page 3-2 of KPCo's IRP Report relates to the continuation of the federal government-implemented Energy Efficiency & Appliance Standards and of customer education programs provided by federal and local government agencies, professional trade organizations, public interest groups and energy services companies, as well as local utility companies.

To elaborate further, the Federal Energy Efficiency & Appliance Standards were established by the U.S. Congress through the 1987 National Appliance Energy Conservation Act & 1988 Amendments, and the 1992 National Energy Policy Act. These standards are continuing to be upgraded and expanded, with the next set of new efficiency standards scheduled to be in place in October 2000 for room air conditioners, and in July 2001 for refrigerators. Additionally, the U.S. Department of Energy has proposed to increase efficiency standards for central air conditioners and heat pumps, and to implement a final ruling on such standards by December 2000. The continuation of these federally mandated standards for product manufacturers will provide consumers with the availability of high-efficiency products such as household appliances, heating and cooling systems, lighting, plumbing products and water heaters, thus enhancing the use of high-efficiency products in the home.

Request No. 7

Response (cont'd)

a. Customer education programs on energy efficiency are available to consumers today through many sources. Examples of such education programs follow.

Energy Star, a partnership between the U.S. Department of Energy (DOE) and the U.S. Environmental Protection Agency, promotes energy-efficient products from all major manufacturers, by labeling such products with the Energy Star label and educating consumers about the benefits of energy efficiency. Products having the Energy Star label include various household appliances, home electronics equipment (TVs, VCRs, home audio, computers, printers, etc.), heating and cooling systems, residential lighting fixtures, windows, roofing material and home insulation.

The Federal Trade Commission's Appliance Labeling Rule requires that EnergyGuide labels be placed on all new refrigerators, freezers, water heaters, dishwashers, clothes washers, room air conditioners, central air conditioners, heat pumps, furnaces and boilers. EnergyGuide labels identify energy consumption characteristics of household appliances, thus allowing the consumer the opportunity to compare annual energy consumption and operating costs of similar appliance models.

The DOE also provides a wealth of information on energy-efficient products through programs such as the Federal Energy Management Program and the Energy Efficiency and Renewable Energy Network. Numerous publications on energy-efficient products are provided to consumers by various professional trade organizations and public interest groups, such as: American Council for an Energy-Efficient Economy (ACEEE), Air Conditioning Refrigeration Institute (ARI), Association of Home Appliance Manufacturers (AHAM), Consortium for Energy Efficiency, Edison Electric Institute (EEI), and Gas Appliance Manufacturers Association. Home building suppliers, such as Lowe's and 84 Lumber, provide brochures on energy-efficient products and construction practices for both contractors and do-it-yourself home builders. Also, aside from utility-sponsored DSM education programs, energy service companies have provided energy product and service information to customers.

In addition to the numerous education programs that are provided to consumers by federal and local government agencies, professional trade organizations, public interest groups and energy services companies, KPCo has incorporated customer education in its DSM programs and provides pertinent information via monthly bill inserts. No estimates have been made of the impacts of KPCo's customer education programs on customer energy use.

Customer education information was also developed by the KPCo DSM Collaborative (which includes a KDOE representative) in conjunction with several DSM programs. A description of the type of information provided with each of these programs follows.

Request No. 7

Response (cont'd)

- The Energy Fitness Program provided to participating customers an educational booklet and an AEP "SMART Energy Savings Tips" video. These educational sources discussed simple energy-saving measures that homeowners could perform to reduce their overall energy consumption. The measures discussed in the booklet and video were in addition to those measures provided and installed in the Energy Fitness Program.

- The Targeted Energy Efficiency Program provides an educational booklet to participating customers. The weatherization staff representatives who conduct the audit discuss with the homeowner the energy-saving measures contained in the booklet, along with the benefits attributable to the installation of the energy conservation measures in the customer's home.

- The Mobile Home New Construction Program is promoted by participating mobile home dealers. The dealers promote high-efficiency heat pumps and provide a "flyer" to each potential participant, explaining the benefits and the potential energy savings associated with the installation of a zone-3 insulation package and a high-efficiency heat pump in a new mobile home.

- The Commercial SMART Audit Program provides an audit report on each participant's facility. The report describes in detail the conditions found at the time the audit was conducted and the recommended energy-saving measures to be installed at the facility. The Class I Audits (less than 100 kW) are mailed to each program participant, and the Class II Audits (at least 100 kW) are delivered to the customer personally by the Company's business services representative or Efficiency Services Supervisor.

The Company also provides bill insert information through its "Consumer Circuit" Program, which includes literature with the monthly bills to all residential customers. The literature explains the benefits of implementing various energy-efficiency measures in the home. Examples of some of the topics included are: NEED Project Education On Energy, Tips For Conserving Electricity, The Heat Pump: A Smart Choice, Efficient Lighting Makes Environmental Sense, Plant Trees To Reduce Your Electricity Usage, Need An Energy-Efficient Water Heater Fast?, and Prepare Now For A Cozy Winter.

b. No; the notion that the normal operation of market forces or Adam Smith's "Invisible Hand" will cause customers to implement all energy efficiency measures that are cost-effective is incongruous and vague; it does not consider energy efficiency measures already in place today, nor the additional non-marketing factors contributing to the establishment of energy efficiency measures in a customer's lifestyle.

Request No. 7

Response (cont'd)

It should be recognized that the implementation of cost-effective energy efficiency measures is not necessarily determined or performed solely by the customer, but rather through other mechanisms, such as mandated Federal Energy Efficiency & Appliance Standards, the establishment of upgraded home building codes, and the availability of energy-efficient products to building, plumbing, electrical and HVAC contractors. Additionally, the promotion of energy efficiency measures through entities such as professional trade organizations, public interest groups and energy services companies encourages customers to implement such measures.

c. Based on the availability of energy efficiency measures on the market today for both contractors and consumers, along with improved Federal Energy Efficiency & Appliance Standards and upgraded home building codes, the Company believes that many of the significant market barriers that may have prevented the implementation of cost-effective energy efficiency measures, such as product or service unavailability, unreliable information, uncertainty of product performance, long payback periods and access to financing, are being overcome. Energy efficiency measures have become established standards for both product manufacturers and building contractors. Additionally, energy efficiency measures will continue to be instituted by government agencies and product manufacturers in the future, along with energy efficiency services and products provided by energy service companies, to promote and establish energy efficiency according to the customer's needs and lifestyle.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

MAR 31 2000

PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING REPORT OF THE KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER TO THE KENTUCKY PUBLIC SERVICE COMMISSION, OCTOBER, 1999	)))))	**CASE NO. 99-437**

KENTUCKY DIVISION OF ENERGY'S COMMENTS RELATED TO THE KENTUCKY POWER COMPANY'S 1999 INTEGRATED RESOURCE PLANNING REPORT TO THE PUBLIC SERVICE COMMISSION

I. INTRODUCTION

The purpose of this analysis is to outline a comprehensive alternative to the integrated resource plan (IRP) presented in the Kentucky Power Company's (KPCo) report to the Commission dated October 21, 1999, in Case No. 99-437. The Kentucky Division of Energy (KDOE) believes that this alternative is in closer agreement with the rationale that underlies integrated resource planning, and offers significant profitable long-term opportunities for the utility company and its shareholders as well as tangible economic benefits for its customers.

II. KDOE'S VISION OF THE FUTURE: A WELL-FUNCTIONING MARKET FOR ENERGY SERVICES

In a well-functioning market, customers would have, or could obtain, adequate information about the life-cycle costs and benefits of their purchasing and investment decisions. Customers would be capable and rational economic decision-makers; i.e., they would be less concerned about the unit price of electricity than about the size of their energy bills and the net value that various competing packages of energy services could provide to their businesses or homes. Businesses would apply the same financial criteria (payback periods or return-on-investment "hurdle rates") to cost-reducing investments as they do to investments that promise to increase sales. In transactions involving multiple parties, accurate information about future energy costs would be reflected in negotiated contractual arrangements, so that those parties bearing the costs of energy upgrades would be compensated by those parties enjoying the benefits. Designers who took the extra time necessary to improve the efficiency and performance of their buildings would be compensated for their efforts by their clients. Financing would be available at market rates for cost-effective energy upgrades. A sufficient number of sellers would compete to serve the market for energy services. Electricity prices would approach marginal costs, which would change throughout the day and year because of generation, transmission, or distribution system constraints, thus passing price signals on to customers. Environmental effects would be monetized at the societally efficient rate, or at least there would be a functioning market for "green power." There might even be a well-developed market in saved energy, or "negawatts,"[1] in Amory Lovins' phrase.

III. THE PRESENT REALITY: PERVASIVE AND CHRONIC MARKET BARRIERS

In stark contrast to the competitive market scenario described in Section II above, present-day markets are riddled with barriers that prevent customers from obtaining the most economically advantageous energy services available to them. As pointed out in a Strategic Issues Paper produced by E Source, "Well over half of the energy used to cool and ventilate buildings in countries like the United States can be saved by improvements that typically repay their cost within a few years." Other analyses "have found comparable potential savings in

[1] "Saving Gigabucks with Negawatts," Amory B. Lovins, *Public Utilities Fortnightly*, March 21, 1985, pp. 19-26.

lighting, drivepower, office equipment and other end-uses."[2] The report continues, "To a theoretical economist, these are astounding statements: it is inconceivable that in a market economy, such large and profitable savings would remain untapped. But to a practitioner who knows how buildings are created and run, it is not only conceivable but obvious."[3] The rest of the report provides a detailed examination of the process by which buildings are designed, built and operated, and how inefficiencies are introduced at every stage through practices which are typical of the commercial construction market. Most of the barriers result from split incentives, perverse incentives, lack of information, and lack of communication between the numerous parties involved. Although each participant may be behaving rationally within his or her narrow area of responsibility, the overall result is a system that chronically undervalues energy efficiency.

Some examples of chronic market failures in the new commercial construction market are listed below:

- Real estate developers and investors, who make early building decisions, discount energy-related issues heavily, focusing on minimizing construction time and cost.
- U.S. rules on taxes and depreciation exacerbate the focus on first cost.
- Developers have very little information about the efficiency gains that are possible.
- Financial institutions may reject innovative designs, fearing delays in approval by code officials.
- Commercial appraisers and securities rating agencies know little about energy and have no way to evaluate designers' projections of energy performance.
- Site planning decisions may be made by professionals with little knowledge of energy before an architect is even hired, despite the fact that "Just proper choice of architectural form, envelope, and orientation can often save upwards of a third of the building's energy at no extra cost – 44% in one recent California design."[4]

[2] "Energy-Efficient Buildings: Institutional Barriers and Opportunities," E Source, Inc., 1992, Boulder, Colorado, p.6.
[3] Ibid.
[4] Ibid., p.11.

- Most architects do not know enough about mechanical systems design and do not work closely with the HVAC professionals.

- Mechanical designers and equipment vendors have economic incentives to oversize systems.

- Few HVAC designers perform dynamic thermal simulations; many use rules of thumb, and some leave system sizing decisions to the equipment manufacturers.

- "For chillers, the most costly and critical component of conventional HVAC systems, the best models are not in the catalogs: a designer must know, and take the trouble, to custom-design an unlisted combination of impeller, gears, heat exchangers, etc."[5]

- The emphasis on "just-in-time" design leaves little time for optimizing whole systems.

- Some designers may worry that if they "achieve large energy savings, someone may ask why they didn't do so long ago."[6]

- Most often, no single member of the design team has overall responsibility for the entire interactive system.

- Even if an interdisciplinary team approach is desired, each profession communicates using different terms and has different incentives, making cooperation difficult.

- "Mechanical engineers are rarely consulted at the conceptual design stage, when the opportunities for energy savings are largest."[7]

- Design fees are not structured to compensate for the extra time needed to optimize systems; in fact, fee structures reward speed above all.

- "Designers' concerns about potential liability are most easily and safely met by oversizing equipment at the client's expense: the designers will pay neither capital nor operating costs, but they know they could be sued or lose clients if occupants are uncomfortable."[8]

- Construction contractors frequently substitute less efficient equipment for what may have been specified; designers are usually not present to catch discrepancies or errors.

- Commissioning of the building's mechanical systems is rarely performed to make sure they work as specified.

[5] Ibid., p.13.
[6] Ibid., p.14.
[7] Ibid., p.18.
[8] Ibid., p.20.

- Thorough documentation on how to run a building optimally is not provided to building operators.

- Although much HVAC equipment fails to meet its specified capacity and efficiency ratings, measurement that could catch such discrepancies is not done.[9]

- Building operators are not trained in or rewarded for energy-efficient operation, and may frequently disable automatic control systems to minimize complaints.

- "HVAC systems worldwide suffer from a pervasive, indeed a nearly universal, lack of high-quality monitoring. Without good data on how systems and components *actually work*, understanding of how best to improve them remains limited..."[10]

- Suppliers of parts and replacement equipment are not rewarded for selling high-efficiency products.

- Commercial leasing brokers are unfamiliar with energy, and tend to use rules of thumb rather than building-specific analyses.

- Commercial leases do not provide both parties an incentive to cooperate to implement energy efficiency upgrades.

- Few commercial tenants know enough about energy efficiency to demand it in the market.

Given this (non-exhaustive) list of barriers in the new commercial construction market, it should not be surprising when analysts reach the conclusion that huge gains in efficiency are technically feasible at very reasonable cost. The Environmental Energy Technologies Division of the Lawrence Berkeley National Laboratory estimates that "If only tune-ups and performance monitoring of existing buildings were performed, average energy use could be reduced by about 20%. If proven efficiency measures were applied when a building is retrofitted (usually about every 15 years), about 50% reduction could be attained. The full range of efficiency measures that can be designed and incorporated into new buildings could bring about an energy reduction of as much as 75%."[11]

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[9] Ibid., p.28.
[10] Ibid., p.30.
[11] Lawrence Berkeley National Laboratory, "Creating High-Performance Commercial Buildings," *EETD News*, Fall 1999, pp. 1-2.

IV. KENTUCKY POWER COMPANY'S INTEGRATED RESOURCE PLAN

When considering future resource needs, KPCo's 1999 IRP states that "AEP should have enough installed generation to reliably serve its anticipated peak demand and energy requirements through about the year 2004. For the years beyond 2004, assuming that the loads materialize as projected, it appears that new generation resources will be needed."[12] The IRP regulation governing integrated resource planning by electric utilities requires a discussion of all options, including "conservation and load management or other demand-side programs not already in place."[13] Other than the single demand-side option of interruptible loads, the IRP does not even consider the possibility of initiating significant new DSM programs. It simply assumes that new generation will be the most cost-effective way to meet all future resource needs (that are not covered by the interruptible load program).

At the beginning of Section 4C, KPCo outlines a 6-step IRP process.[14] The steps are:

1. Development of the base-case load forecast
2. Determination of overall resource requirements
3. Identification and screening of supply-side resource options
4. Identification and screening of DSM options
5. Integration of supply-side and demand-side options
6. Analysis and review

In our view, KPCo did not effectively perform step 3. Rather than "speculating as to the specifics of possible future generation resource additions"[15], KPCo simply made certain assumptions about the kinds of future resources that would be added. KPCo short-circuited step 4 by declining to analyze any potential new DSM options or programs, and it short-circuited step

[12] KPCo 1999 IRP, p. 1-9.
[13] 807 KAR 5:058, Section 8.
[14] KPCo 1999 IRP, p. 4-7.
[15] Ibid., p. 1-9.

5 by declining to analyze demand-side and supply-side options on a consistent, quantitative basis – instead making the assumption that all future needs would be met by new generation (and interruptible loads). KDOE is concerned that a document in which three of the six steps are not effectively performed may not serve as an adequate basis for cost-effective future resource acquisition decisions. Although the electric industry in Kentucky may someday be restructured, we must point out that at present it is still regulated on a traditional cost of service basis, that in any event the distribution part of the industry will remain a regulated monopoly, and that resource plans should reflect the present reality.

Existing DSM programs are capped at a level that we must describe as token. In terms of energy impacts, KPCo projects savings of 4 GWH in 2000 and 7 GWH in 2004, which represents 0.05% and 0.09% of its total internal energy requirements, respectively.[16] Annual energy savings are projected to remain constant at 7 GWH from 2004 through 2014 and then decline. Most of these savings come from the residential sector, with only 1 GWH per year from the commercial sector and with no DSM programs planned for the industrial sector at all.[17] In comparison, for the country's 508 large electric utilities in 1998, energy savings resulting from DSM programs averaged 1.5% of electric sales to ultimate consumers.[18] The average large utility's DSM energy impacts are thus 16 to 30 times greater than those of KPCo. While it is true that these impacts have been declining somewhat in recent years as the utility industry has been restructured in certain states and some companies has cut back on DSM programs, it is clear that the scale of KPCo's DSM programs have never approached the industry average.

Furthermore, the industry average is far below what is justifiable economically. We are not aware of any evidence indicating that the DSM programs operated by other utilities come close to harvesting all of the available efficiency gains that are cost-effective from a societal

[16] KPCo 1999 IRP, Exhibits 2-12 and 2-13.
[17] Ibid., Exhibit 2-13.
[18] Energy Information Administration (USDOE), "Electric Utility Demand Side Management 1998".

perspective. The magnitude of the total savings, even for those utilities with relatively extensive DSM programs, is certainly far below what is possible according to technical potential studies, and existing utility DSM programs have always been a work in progress. According to Amory Lovins:

> "It is no secret to my clients and audiences since the 1970s that most utilities' efficiency programs in most sectors and most end-uses, though cost-effective, are in fact suboptimized. They're pretty good, but they could be better. They choose poorer technologies, or combine them less artfully, than the packages we analyzed; or they deliver them with poorer quality control or in less streamlined fashion than best practice; or they incur excessive transaction costs; or they use a well-known collection of thoroughly avoidable ways to overpredict actual savings."[19]

KPCo has not analyzed a wide range of potential new DSM programs and measures since 1994.[20] The analyses that AEP/KPCo has conducted during the period from 1995 to 1999 have focused on refining and enhancing DSM programs that were already in existence in the KPCo service territory, or on identifying programs to be eliminated.[21] In several meetings during the course of the DSM Collaborative's existence, the KDOE representative proposed major new initiatives in the areas of new commercial construction and industrial energy efficiency, areas where we believe the potential savings to be very large. Most of these suggestions were politely but firmly rejected, either by KPCo or by other members of the Collaborative, with the notable exception of the Mobile Home New Construction Program in 1995.[22] At meetings during the latter part of 1999, it became clear that in view of the possible future restructuring of the electric utility industry in Kentucky, AEP has made a decision at the corporate level not to consider,

[19] Lovins, Amory, "Apples, Oranges, and Horned Toads: Is the Joskow & Marron Critique of Electric Efficiency Costs Valid?" *Electricity Journal*, May, 1994, p.40.
[20] KPCo's response to KDOE Information Request #2, 2nd set.
[21] KPCo's responses to KDOE Information Requests #8, 9, and 12, 1st set, and #2, 2nd set.
[22] KPCo's response to KDOE Information Request #9e, 1st set.

propose, or institute any major new DSM programs. Several statements in the IRP confirm this impression.[23]

Part of the explanation for KPCo's approach may be found in its observation that "in anticipation of deregulation, the emphasis of the DSM evaluation process has been shifted from a societal perspective, as reflected in the Total Resource Cost (TRC) test, to the ratepayer perspective, as reflected in the Ratepayer Impact Measure (RIM) test".[24] KDOE, however, believes that the TRC test is still the most appropriate benefit/cost test to use in integrated resource planning, for reasons that are explained in Section V below.

There are short-term economic reasons why KPCo might want to pursue this kind of apparently low-risk strategy. Investments in certain demand-side resources might not be recovered if the industry is restructured and a particular customer chooses another energy service provider. The likelihood that KPCo will be left with net stranded costs, however, is virtually nil. States that have implemented restructuring have all made provision for the recovery of net stranded costs by utilities. Any regulatory costs resulting from increased DSM investments over the next several years would almost certainly be swamped by the large "negative stranded costs," or stranded benefits, that KPCo shareholders would stand to gain through industry restructuring. A recent study gave a range of estimates with stranded benefits for KPCo ranging from approximately $295 million in the "Technical Innovation" scenario to $694 million in the "High Electricity Price" scenario.[25] KPCo therefore has little reason to fear that large-scale DSM programs will cause the company's prospects to shift from a stranded benefit to a stranded cost scenario. The strategy embodied in KPCo's IRP only seems to be a low-risk one, however,

[23] KPCo 1999 IRP, pp. 3-5, 3-9, 3-10, and Exhibit 3-5.
[24] KPCo 1999 IRP, p. 3-5.
[25] Resource Data International (RDI), "Stranded Costs and Electricity Exports in a Restructured Electric Industry," Interim Report No.2 for the Kentucky Special Task Force on Electricity Restructuring, August, 1999, Appendix A-1.

because it tends to lock KPCo into the role of a vendor of commodity electricity, which is likely to become an extremely competitive business at some future time.

It should be noted that no criticism is being made of KPCo's administration of its existing DSM programs. Considering the limited resources that have been made available, KPCo's program staff have worked with dedication and skill to implement the programs effectively, make improvements in them when needed, and shift resources from underperforming programs to ones that were performing better than projected.

V. AN ALTERNATIVE SCENARIO: MARKET TRANSFORMATION

Even though KPCo does not anticipate a need to acquire resources until 2005, and there is no timetable yet in effect for electric industry restructuring in Kentucky, it is not too early for the company to initiate a comprehensive reexamination of its relationship to the market. The strategy we suggest is for AEP to refocus its perspective from being a vendor of electrons to an energy service company. Such a redefinition would have profound implications, and it could be implemented whether or not the industry is ever restructured in Kentucky.

It has long been a truism that customers do not need or desire energy or electricity per se, but rather the services – warmth, light, hot water, cooling, drive power – that it provides for them. An economically rational customer will seek to maximize the net value of energy services purchased (i.e., the value added by the energy services minus the energy bill). An energy company that helps its customers maximize this value should enjoy a large market demand for its services.

Is it realistic to think that a company that sells a commodity can change its approach to one of helping its customers maximize value, even when it might result in less of the commodity being sold? The book *Natural Capitalism*, by Paul Hawken, Amory Lovins, and Hunter

Lovins,[26] describes several companies that are making the transition. Carrier, the world's largest manufacturer of air conditioning equipment, is now offering a "comfort lease" that ensures a certain indoor temperature during hot weather. Carrier can choose from a range of means to deliver the comfort: by doing lighting retrofits, installing high-performance windows, or installing its air conditioning equipment. "The less equipment Carrier has to install to deliver comfort, the more money Carrier makes. If Carrier retrofits a building so it no longer needs a lot, or even any, of its air conditioning capacity, Carrier can remove those modules and reinstall them elsewhere."[27]

The same concept is prevalent overseas:

> "Ten million buildings in metropolitan France have long been heated by *chauffagistes*; in 1995, 160 firms in this business employed 28,000 professionals. Rather than selling raw energy in the form of oil, gas, or electricity – none of which is what the customer really wants, namely warmth – these firms contract to keep a client's floorspace within a certain temperature range during certain hours at a certain cost. The rate is normally set to be somewhat below that of traditional heating methods like oil furnaces; *how* it's achieved is the contractors' business. They can convert your furnace to gas, make your heating system more efficient, or even insulate your building. They're paid for results – warmth – not for how they do it or how much of what inputs they use to do it. The less energy and materials they use – the more efficient they are – the more money they make. Competition between *chauffagistes* pushes down the market price of that "warmth service." Some major utilities, chiefly in Europe, provide heating on a similar basis, and some, like Sweden's Goteborg Energi, have recently made it the centerpiece of their growth strategy."[28]

Other examples:

- "Some utilities and third parties have been offering "torque services" that turn the shafts of your factory or pumping station for a set fee; the more efficiently they do so, the more they can earn."[29]

[26] Rocky Mountain Institute, Snowmass, Colorado, 1999-2000
[27] *Ibid.*, p. 135.
[28] *Ibid.*
[29] *Ibid.*, p. 136.

- Dow Chemical has started moving toward providing "dissolving services" rather than merely leasing solvents; their German affiliate plans to charge by the square centimeter degreased instead of by the amount of solvent used, thereby providing an incentive for its technicians to use less solvent rather than more. (Even better would be to use environmentally safer or no solvents.)

- Ciba's Pigment Division is moving to provide "color services" rather than merely selling dyes and pigments.

- Cookson in England leases the insulating service of refractory liners for steel furnaces.

- Pitney Bowes handles your firm's mail instead of just leasing postal meters.

- Interface in Atlanta leases floor-covering services rather than selling carpet. Interface is responsible for keeping it clean and fresh, replaces parts of it when indicated by monthly inspections, and reduces overall life-cycle costs. Interface has also developed a new polymeric floor covering material, called Solenium, that combines many of the performance advantages of carpet and hard flooring and can replace carpet altogether.[30]

In each case, the firms providing the service may sell somewhat less of their commodity or product, but are able to meet the customer's actual needs in a more efficient way. They are paid for results – providing value to the customer – rather than for the quantity of inputs. The incentives of the service provider and the customer are no longer at odds; both parties are interested in performing the needed function in the most efficient way possible. This concept may represent a cutting-edge trend in our economy.

If AEP were to change the focus of its activities from a being a low-cost vendor of electrons to a provider of cost-effective energy services, it would initiate a number of programs and actions aimed at optimizing overall efficiency throughout the energy sector. Some of these initiatives would have immediate profit potential, while others would help transform energy markets so that customers would value more highly, and demand, the kinds of services provided by AEP. The longer-term initiatives would also help establish AEP's image in the market as an efficiency-oriented company interested in providing maximum value to its customers.

[30] *Ibid.*, pp. 137-141.

In the following section, we suggest a number of initiatives that could be investigated for possible implementation:

A) Establish an AEP-owned energy service company (ESCO), or form joint ventures with (or purchase) one or more existing ESCOs.

If AEP is to transform itself into an energy service company, it needs to begin gaining direct experience in this market as soon as possible.

B) Use Local Integrated Resource Planning (LIRP)

The method of local integrated resource planning, as described in a 1995 strategic issues paper by E Source, is designed to determine if costs could be reduced by deferring transmission and distribution upgrades through the use of geographically-focused demand-side programs.[31] Through a request for information and a follow-up request, we have concluded that AEP/KPCo does not presently consider implementing targeted demand-side programs when planning how to meet future transmission and distribution (T&D) needs.[32] While the installation of the world's first Unified Power Flow Controller is a commendable initiative that reduces system losses and helps advance the industry's technology base, it still leaves unexplored the demand-side measures that might reduce total resource costs even more.

The E Source paper provides case studies illustrating how a number of utilities have used LIRP to forestall costly T&D upgrades. In 1993, Ontario Hydro planners were facing rapidly-growing demand in the Collingwood area and projected a T&D upgrade costing C$83 million. After conducting a LIRP analysis, however, they developed a strategy that combined load-shifting residential water heaters, improving lighting efficiency, scheduling the operation of industrial furnaces, and making much smaller T&D upgrades, for a total cost of C$24.3 million, which included the cost of analyzing and administering the alternative strategy. Similar results

[31] E Source, "Local Integrated Resource Planning: A New Tool for a Competitive Era," Boulder, Colorado, 1995.
[32] KPCo's response to KDOE Information Requests #15, 1st set and #3, 2nd set.

were obtained in numerous other locations. Overall, Ontario Hydro credits LIRP with deferring some C$1.7 billion in T&D investments through September, 1995. LIRP has become the standard method of planning customer service and T&D planning. In the words of one distribution planner, "LIRP has become our business."[33]

The New York State Electric and Gas Corporation was able to avoid a $6.5 million T&D upgrade by providing an interruptible service rate to one large user and contract to dispatch the user's two 300-kW backup generators, all at a hardware cost of $45,000.[34]

The E Source paper concludes with a summary of advantages utilities can obtain by making use of the LIRP approach. The following benefits, which are reprinted from the E Source Strategic Issues Paper, would apply whether or not the utility industry is restructured in Kentucky:

- *"Improves utilization of existing T&D system assets while increasing grid reliability,* leading to lower costs per unit of electricity delivered, and deferred or avoided capital expenditures.

- *"Expands knowledge of the true cost of supplying electricity to a particular area at a specific time.* This information would be vital should a utility wheel power from another supplier to a retail customer. Such information can also be used by internal business units.

- *"Provides risk insurance during power sector restructuring.* With the future structure of the electricity industry uncertain, deferring capital expenditures makes additional economic sense from a risk reduction perspective. No one can predict who will own the grid in the future, or what compensation might be provided should ownership change.

- *"Reduces the need to obtain regulatory and public approval for potentially contentious T&D projects.* By reducing the need for new and upgraded powerlines and other T&D hardware, utilities clearly benefit in the public relations arena.

- *"Avoids long-term commitments to one-time, high-cost, supply-side options by investing in more flexible and modular technologies.* Incrementally adding capacity is likely to ensure that capital investment accurately reflects the needed demand rather than potentially overinvesting in a supply-side option---a particular concern for

[33] E Source, 1995, pp. 6-8.
[34] Ibid., p. 10.

utilities that are experiencing slow growth in demand or that now service demand that might disappear.

- *"Provides experience with additional modular technologies whose costs are falling as production scales up.* Examples include advanced gas turbines, fuel cells, photovoltaics, chemical-battery storage, and flywheels.

- *"Provides customers with higher-quality service.* This should occur since the LIRP process is driven by the customer's concerns and needs. In fact, the LIRP approach could be used in determining the needs of individual customers, a key marketing foundation that could aid customer retention in the future.

- *"Maintains profitable load.* Once a utility looks closely at customer uses, it may discover a potential loss of load to competing fuels. Upon such a finding, the utility can develop a load retention program, as appropriate. LIRP may also reveal that some loads are not economic to serve and thus are good candidates for fuel switching or other measures.

- *"Assists a utility in getting various department plans in sync with each other.* Once a utility starts using LIRP as the start of its planning process, the utility can produce marketing, customer service, and sales plans that are more consistent with its distribution plans. This also increases the likelihood of producing a coordinated interface and a consistent relationship with customers.

- *"Leads to better utilization of generating assets.* Peak clipping options (storage and generation) would result in higher utilization of baseload generators. Smaller generating units also can lead to smaller reserve capacity requirements, and distributed generation can cut grid losses."[35]

C) Initiate a Comprehensive Program in New Commercial Construction

To overcome the litany of chronic market barriers to energy-efficient new construction outlined in Section III above, a multi-pronged approach is advisable. The magnitude of the potential savings can be estimated by performing a technical potential study or by comparing the efficiency of typical new buildings being constructed today with state-of-the-art buildings in other jurisdictions. Since AEP/KPCo has subscribed to E Source,[36] an excellent way to start the analysis of the technical potential would be to study the E Source Technology Atlas Series, which include the following titles: "Commercial Space Cooling and Air Handling," "Lighting,"

[35] Ibid., pp. 22-23.
[36] KPCo's response to KDOE Information Request #6, 1st set.

"Drivepower," "Space Heating," and "Residential Appliances." A major theme of these highly detailed, thoroughly-documented works is that there are major efficiencies to be gained through the whole-system integration of properly-sized technologies. Initial costs can frequently be reduced through careful, whole-system design.

Indirect economic benefits such as increased retail sales[37] or improvement in the performance of students or workers[38],[39] can make total benefit/cost ratios extremely high. For example, while the energy savings generated by the daylight-oriented whole-building design of Lockheed's 600,000 square foot office building in Sunnyvale, California paid back the initial extra costs in four years, absenteeism in a known population of workers dropped by 15%, which represents annual cost savings equal to the entire incremental cost of the improved design. To this could be added productivity gains estimated at another 15%, bringing the payback period down to a matter of weeks.[40]

There are several ways KPCo could enter the market for energy-efficient design services. One way would be to establish an architectural/design firm, or purchase or form a joint venture with one or more existing firms. Another would be to initiate a program providing training, design incentives, and awards for energy-efficient architects, engineers, and HVAC system designers. A joint venture with a manufacturer of energy-efficient mobile homes or modular homes would be another possible way to share in the efficiency gains.

An instructive example of what other investor-owned utilities are doing is the Pacific Gas & Electric Energy Center (PEC), established by PG&E in December, 1991. The PEC provides educational programs, consulting services and building performance tools to architects, HVAC

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[37] Heschong Mahone Group, "Skylighting and Retail Sales," submitted to Pacific Gas and Electric Company on behalf of the California Board for Energy Efficiency Third Party Program, 1999.

[38] Romm, Joseph J. and William D. Browning, "Greening the Building and the Bottom Line: Increasing Productivity Through Energy-Efficient Design," Rocky Mountain Institute, Boulder, Colorado, 1994, p. 11.

[39] Heschong Mahone Group, "Daylighting in Schools: An Investigation into the Relationship Between Daylighting and Human Performance," submitted to Pacific Gas and Electric Company on behalf of the California Board for Energy Efficiency Third Party Program, 1999.

[40] Romm and Browning, op. cit., pp. 8-9.

engineers, electrical engineers, lighting designers, building owners, facility managers, and facility engineers. Its goal is to train professionals and create a sustainable market demand for energy-efficient design and products. It applies a whole-building approach aimed at optimizing owner value, user comfort, and energy efficiency.[41] A recent study concluded that the PEC is effectively reaching its intended audience and is causing long-lasting behavioral changes that lead to more energy-efficient buildings.[42]

A multi-pronged program aimed at transforming the market for energy-efficient new commercial buildings would encompass training and technical assistance for the numerous parties involved in the design, construction, and financing aspects of this market sector. It could include an awards program to recognize and reward the parties involved in producing and operating highly-efficient new buildings. It could work with building code officials to "raise the floor" of performance, thus complementing the awards program at the high-performance end. Another way to impact the low-efficiency end of the market would be to amend the hookup fee policy so that energy-efficient new buildings would be charged a low fee, or even would receive a rebate for hooking up to the grid, while energy sieves would be charged a much higher fee to cover some of the additional costs of distributing power to an inefficient building over its lifetime. Such a policy would affect initial costs, which would get the attention of a segment of the market that might not otherwise respond to information about energy efficiency.

D) Promote Cogeneration to Gain Thermal Efficiencies

KPCo presently "neither encourages nor discourages the installation of combined heat and power (cogeneration) systems by industrial firms in its service territory."[43] The rates paid to cogenerating customers for their excess energy, however, are significantly lower than the retail

[41] Pacific Energy Center web site.
[42] Reed, John H. and Nicholas P. Hall, "PG&E Energy Center Market Effects Study," TecMRKT Works, Arlington, Virginia, May, 1998.
[43] KPCo's response to KDOE Information Request #8, 2nd set.

energy prices charged by KPCo. The KPCo Tariff M.G.S. (Medium General Service), for example, for customers with a normal demand between 5 and 100 kW, lists prices of 4.262 to 5.23 cents per kWh purchased, while the COGEN/SPP I Tariff for cogenerators below 100 kW lists prices of 1.45 to 1.72 cents per kWh sold back to KPCo. The latter rates are based on the utility's "avoided costs," and serve as a disincentive for firms to cogenerate.

Central power plants are on the order of 33% efficient, with the remaining two-thirds or so of the fuel energy converted to waste heat. Combined heat and power systems, however, can make beneficial use of 80% or more of the energy content of the fuel.[44] A firm seeking to optimize the efficiency of the energy sector as a whole would develop programs to enable customers with sizeable thermal loads to put this vast amount of wasted energy to use, and would develop shared savings arrangements to enable both parties to benefit from the increase in system efficiency. One possible way for KPCo to enter this market would be to form a joint venture with a cogeneration project developer, as Cinergy has done with Trigen Energy.

E) Promote Distributed Generation and Green Power through Net Metering

Some analysts believe that the electric industry of the future will make much greater use of small-scale, distributed generation units, and that such a trend would fit well with the needs of a more competitive industry.[45] Distributed resources "could be applied at or near customer sites to manage multiple energy needs and to meet increasingly rigorous requirements for power quality and reliability. Distributed generators could also be deployed at utility sites – for example, at substations for transmission and distribution grid support. Some experts predict that 20% or more of all new generating capacity built in the United States over the next 10 to 12 years could be for distributed applications..."[46]

[44] Casten, Thomas R. and Mark C. Hall, "Barriers to Deploying More Efficient Electrical Generation and Combined Heat and Power Plants," Trigen Energy Corp., revised March, 2000.
[45] Moore, Taylor, "Emerging Markets for Distributed Resources," *EPRI Journal*, March/April, 1998, pp. 8-17.
[46] *Ibid.*, pp. 9-10.

In an effort to promote cost-effective distributed generation and renewable energy technologies, approximately thirty states have instituted "net metering."[47] Net metering laws (enacted by legislatures) or orders (instituted by public utility commissions) require electric utilities to purchase excess power from small-scale, renewable sources at the same retail rate they charge those customers. In effect, the owner of a small photovoltaic system can "run the meter backwards" when the system is producing more power than needed. Net metering policies usually set an upper limit on the size of the systems that are covered, and usually prohibit the utility from erecting other barriers such as unreasonably burdensome interconnect and safety requirements. Certain renewable energy technologies, including photovoltaics, can provide system benefits by producing at their peak output on hot, sunny, summer days when the system may be facing its peak annual load.

Net metering would make small-scale distributed generation by customers more economically feasible. Because power is generated on-site, distributed generation would reduce transmission and distribution losses and improve the efficiency of the electricity grid. Certain renewable energy technologies such as photovoltaics can reduce costs system-wide by producing at their peak output on hot, sunny, summer days when the system may be facing its peak annual load.

F) Support Statewide and Regional Market Transformation Initiatives

The term "market transformation" refers to a set of planned interventions in the market that lead to longer-lasting impacts than traditional utility-sponsored DSM programs that are dependent on ongoing rebates for their effectiveness.[48],[49]

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[47] Starrs, Thomas J., "Summary of State Net Metering Programs (Current)," updated September, 1999.
[48] Meyers, Edward M., Stephen M. Hastie, and Grace M. Hu, "Using Market Transformation to Achieve Energy Efficiency: The Next Steps," Electricity Journal, May, 1997, pp. 34-41.
[49] Hall, Nick and John Reed, "Market Transformation: Expectations vs. Reality," *Home Energy*, July/August, 1999, pp. 16-20.

Although some market transformation initiatives may not offer as much potential for short-term profit as some of the other measures discussed above, the participation of AEP/KPCo in market transformation activities could help the company establish its image in the market as an expert in energy efficiency, and as a company dedicated to maximizing the value its customers receive from the energy they purchase.

Regional market transformation alliances have been established in California, the Northwest, the Northeast, and the Midwest. Efforts typically involve a wide range of participants, and may include utilities, energy users, manufacturers, vendors, engineers, architects, construction firms, developers, building code officials, building owner associations, real estate professionals, lending institutions, federal agencies such as the U.S. Department of Energy and U.S. Environmental Protection Agency, state energy offices, and other parties.[50]

Kentucky companies and other interested organizations would be eligible to join the Midwest Energy Efficiency Alliance (MEEA). The mission of MEEA is "to work as a regional network of organizations to develop, design and implement energy efficiency and renewable energy resources in the rapidly-changing Midwest energy markets. The goals are to increase public value, improve environmental quality, lower energy costs, and promote sustainable economic development."[51]

The Northwest Energy Efficiency Alliance, founded in 1997, has already reduced regional demand by 16 MW through market transformation initiatives related to compact fluorescent light bulbs, residential clothes washers, and semiconductor manufacturing process improvements.[52] The California Board for Energy Efficiency administers a variety of market transformation programs, including increasing the use of performance contracting with energy

[50] Meyers et al., op. cit., p. 40.
[51] Midwest Energy Efficiency Alliance web page, updated 2/23/00.
[52] Northwest Energy Efficiency Alliance, "Northwest Utilities to Invest $100 Million in Energy Efficiency through a Regional Alliance," press release, March 17, 2000.

service companies, work with lighting manufacturers and distributors to bring energy-efficient lighting products to the market, home duct system improvements, and design tools for commercial architects and engineers.[53] Northeast Energy Efficiency Partnerships, Inc., has launched market transformation programs in diverse areas including residential appliances, energy codes, high-efficiency motors, and commercial lighting design.[54]

To sum up, there are opportunities for significant improvements in energy efficiency in every sector of the energy market. A good way to identify promising market opportunities is to focus on total resource costs. Wherever a TRC analysis indicates a large savings potential, the market may be ripe for the development of a particular new energy service offering, shared savings arrangement, or market transformation initiative. Rather than drifting into a future role as one of a large number of competing vendors of commodity electricity, KDOE hopes that KPCo will seriously consider initiatives like those outlined in this section, and will develop ways of adding more value to the energy sector in Kentucky.

[53] California Board for Energy Efficiency, "About the CBEE," web page updated 9/15/99.
[54] Northeast Energy Efficiency Partnerships Initiatives web page.

VERIFICATION

I, Geoffrey M. Young, state that I have written the above document and that to the best of my knowledge and belief all statements and allegations contained therein are true and correct.

Geoffrey M. Young

Geoffrey M. Young, Assistant Director
Division of Energy
Department for Natural Resources

Subscribed and sworn to before me by Geoffrey M. Young, this the 31 day of March, 2000.

Martha Sherman

NOTARY PUBLIC

My Commission Expires: March 3, 2004.

Respectfully submitted,

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COUNSEL FOR NATURAL RESOURCES
AND ENVIRONMENTAL PROTECTION

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing **KENTUCKY DIVISION OF ENERGY'S COMMENTS RELATED TO THE KENTUCKY POWER COMPANY'S 1999 INTEGRATED RESOURCE PLANNING REPORT TO THE PUBLIC SERVICE COMMISSION** was mailed, first class, postage prepaid, the 31st day of March, 2000, to the following:

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MAR 29 2000

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:

THE INTEGRATED RESOURCE PLANNING REPORT)
OF KENTUCKY POWER COMPANY d/b/a AMERICAN) Case No. 99-437
ELECTRIC POWER COMPANY)

COMMENTS OF THE ATTORNEY GENERAL
ON THE 1999 IRP OF KENTUCKY POWER COMPANY
D/B/A AMERICAN ELECTRIC POWER COMPANY

In October of 1999, Kentucky Power Company(KPC)filed its 1999 Integrated Resource Plan (IRP), which covered both its future plans for Kentucky, and the future plans of its parent company, American Electric Power (AEP). The integrated plan includes a load forecast and the Company's plans for both supply and demand side resources to meet projected future needs. The plan also looks at other issues including transmission, fuel procurement, and acid rain compliance. The Office of Attorney General of the Commonwealth of Kentucky has reviewed the plan and offers the following comments.

In general, the IRP does provide a comprehensive roadmap that should allow KPC to meet future needs of customers. To ensure that future customer needs are satisfied at the lowest possible cost to customers in

Kentucky, certain areas require special vigilance from both KPC and the Commission.

The biggest issue facing KPC in the near future is the loss of the Rockport capacity in January 2005. Kentucky Power is already capacity deficient with respect to the AEP system. When the lease for Rockport expires at the end of 2004, KPC will become extremely capacity deficient. As a result, KPC will be assigned 300 MW of the 500 MW of additions scheduled for the entire AEP system in 2005. While 500 MW is not significant for the AEP system as a whole, the 300 MW for the KPC system constitutes an increase in capacity of 30%. The rate implications for Kentucky ratepayers are significant.

Due to the long lead times associated with adding some types on new capacity, KPC needs to begin now to evaluate its options. The most obvious option is to explore a renewal of the lease with Indiana and Michigan (I&M) for the Rockport capacity. The lease has already been extended once for the 5-year period between 2000 and 2004. While the current lease contains no provisions for renewal beyond 2004, KPC should explore this option. If operating in a deregulated market changes customer loads, I&M may find that predictable revenues from a unit power sale to KPC may provide revenue stability. KPC should initiate this conversation with I&M, before this capacity is committed to another utility.

The capacity deficiency associated with the loss of Rockport by KPC is only a problem if the AEP system as a whole becomes capacity deficient. As long as the AEP system has enough capacity, KPC's deficiencies are covered by the other AEP utilities through the Intersystem Agreement. Because of KPC's responsibility for the added capacity, it is only when capacity must be added to the AEP system that KPC customers become at risk of large rate increases to cover the cost of capacity additions. Therefore, it behooves both KPC and the Commission to keep an eye on a number of items that may affect the timing and nature of capacity additions that will be needed for the AEP system.

The first item that should be tracked is load growth. The IRP projects annual load growth at about 2% per year. This projection appears to be high. The IRP reveals that KPC's load growth failed to meet the projections contained in its 1996 IRP (Exhibit 2-34). In addition, the weather corrected load growth shown in Exhibit 2-30 appears to be flat in recent years. Actual weather corrected loads experienced in 1999 were significantly below those projected in this 1999 IRP. Furthermore, load growth has been flat during a period of economic boom. Should the economy turn downward, as economic cycles suggest it will, is seems likely that the projected 2% annual load growth is not realistic. If load growth is less than projected, the need for generating capacity will be postponed.

The second item that should be tracked is the effect of deregulation in those states in which the AEP sister companies operate, which will affect the AEP system capacity available for KPC use. Changes may occur in load and in the number of plants maintained by the system as a result of deregulation.

Ohio has deregulation legislation in place now. Competition in Ohio may produce differences in the amount of capacity available to satisfy sister company needs under the Intersystem Agreement. If other AEP companies deregulate and gain or lose customers in amounts greater than standard monopoly load growth as a result of local deregulation, the amount of surplus AEP system capacity available to supply capacity deficient KPC could be affected. Deregulation could also render less efficient power plants uneconomical. The retirement of uneconomical plants could cause the current capacity surpluses on the AEP system to be reduced, thus causing KPC to add expensive new capacity. While it is too early to understand what effects deregulation in Ohio and other states will have on KPC through the Intersystem Agreement, developments should be tracked closely.

The third item which should be tracked is the availability of OVEC power. The Ohio Valley Electric Corporation (OVEC) owns 2300 MW of low cost generating capacity that supplies electricity to the U.S. Enrichment Corporation's Portsmouth Gaseous Diffusion Plant. The financial problems associated with enriching uranium at the two remaining plants in the United States make it likely that one of the U.S. enrichment plants will be closed. Under the agreement, neither plant can be closed until 2005 unless the Enrichment Corporation's financial condition significantly deteriorates. But, given the current financial difficulties, it seems likely that one the remaining plants will be closed barring a bailout from Congress.

If the plant closed is the Portsmouth facility, the OVEC capacity could become available to the participating utilities. AEP companies own 42% of OVEC or 966 MW. Should this capacity become available, AEP could postpone the need to add capacity until 2007. This possibility was not included in the IRP as a way to meet future capacity needs. AEP should begin now to explore how existing contracts can be used or modified to assure that its low cost OVEC capacity will become available if the Portsmouth plant is closed.

This report did an inadequate job of including the impact of pending environmental regulations, including Global Climate Change and NOx emissions. AEP has indicated that it will not include these environmental considerations until they become law. Unless environmental considerations are included in planning, future capacity additions may exacerbate these problems instead of correct them, causing higher rates for customers for many years into the future. A prime example is the global climate change.

AEP has signed on to the Clinton Administration's Global Climate Change Initiative. Under this agreement, AEP is to voluntarily reduce its carbon dioxide emissions to 1990 levels by 2010. But the IRP shows that AEP will substantially miss meeting this commitment. AEP's CO2 emissions were 107 million tons in 1990. The IRP projects CO2 emissions to be 142 million tons in 2010, a 33% increase from 1990 levels. The Kioto Protocol goes further, calling for a 7% reduction below 1990 levels. If these voluntary reductions are made mandatory, AEP will have a very difficult time reducing CO2 emissions. This could be expensive for AEP.

For example, if AEP must pay a $50 fee for every ton of CO2 over its 1990 emissions, under the IRP projections, by 2010 AEP will have to pay an annual penalty of $1.75 BILLION. This cost would be passed on to ratepayers. If AEP had to pay $50 per ton for all CO2 emissions, such as with a carbon tax, that cost to ratepayers would be over $7 BILLION annually. With such potentially high liability, this contingency must be included in the IRP.

AEP has one lone planned capacity addition which will produce no CO2 emissions - a hydro plant in West Virginia. Including a cost for future CO2 emissions would give renewable energy options which have no emissions proper financial weighting in the IRP. Even if AEP does not include CO2 and NOx costs in its primary IRP plan, additional plans should be considered that include these costs so the Commission can see the marginal cost associated with proactive actions in light of likely future environmental regulations.

Respectfully Submitted

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601
(502) 696-5458

CERTIFICATE OF SERVICE AND NOTICE OF FILING

I hereby give notice that I have filed the original and ten copies of the foregoing with the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601 and certify that this the 29th day of March, 2000 I have served the parties by mailing a true copy of same to:

Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
P. O. Box 1428
Ashland, KY. 41105 1428

Honorable Judith A. Villines
Stites & Harbison
P. O. Box 634
Frankfort, KY. 40602 0634

John Stapleton

Director of Energy
Natural Resources and Environmental Protection
663 Teton Trail
Frankfort, KY. 40601

[signature]

Paul E. Patton, Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Martin J. Huelsmann
Executive Director
Public Service Commission

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B. J. Helton
Chairman

Edward J. Holmes
Vice Chairman

Gary W. Gillis
Commissioner

March 24, 2000

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American Electric Power
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Mr. Michael Kurtz
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Ms. Iris P. Skidmore
Counsel for Natural Resources
And Environmental Protection
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, Kentucky 40601

Mr. John Stapleton
Division of Energy
663 Teton Trail
Frankfort, Kentucky 40601

RE: Case No. 99-437
American Electric Power - Kentucky

Dear Madams and Sirs:

Enclosed please find a memorandum that has been filed in the record of the above referenced case. Any comments regarding the memorandum's contents should be submitted to the Commission within five days of receipt of this letter.

Sincerely,

Martin J. Huelsmann
Executive Director

Attachment

EDUCATION PAYS

INTRA-AGENCY MEMORANDUM

KENTUCKY PUBLIC SERVICE COMMISSION

FILED

MAR 24 2000

PUBLIC SERVICE COMMISSION

TO: Case File No. 99-437

FROM: Jeff Shaw

DATE: March 24, 2000

RE: Informal Conference of March 15, 2000
Regarding AEP/Kentucky Power's 1999
Integrated Resource Plan Filing

On March 15, 2000, an informal conference was held at the Commission's offices in Frankfort, Kentucky, for the purpose of discussing issues related to American Electric Power/Kentucky Power Company's ("AEP/Kentucky) 1999 Integrated Resource Plan ("IRP"). The parties represented at the conference were AEP/Kentucky, the Office of the Attorney General ("AG") the Natural Resources and Environmental Protection Cabinet's Division of Energy ("NREPC") and the Commission Staff. A list of the attendees is attached to this memorandum.

Issues raised by the AG included the impact of deregulation in Ohio on AEP/Kentucky since it has affiliates operating in Ohio and whether those affiliates had any plans to spin off their generation assets or whether they might be faced with having to retire generating units that were no longer economic to operate. AEP/Kentucky indicated that its Ohio affiliates had no plans to spin off their generation assets at the present time and that it did not foresee deregulation in Ohio having any negative impact on its Kentucky operations. It also indicated that it had not significantly studied the issue of units potentially being retired because they were no longer economic to operate. The AG also questioned whether the merger of AEP and CSW would result in lower cost power produced in the AEP, or East Zone, of the merged entity, being shipped to the CSW, or West Zone, of the merged entity, to the detriment of the East Zone customers, which include AEP/Kentucky's customers. AEP/Kentucky stated that the dispatch of power after the merger would not negatively impact its customers and that the synergies produced by the merger would benefit its customers.

The AG also raised questions about AEP/Kentucky's plans for future capacity needs and the extent to which those plans reflected the scheduled termination of the Rockport Unit Power Agreement and the possibility that the Ohio Valley Electric Corporation ("OVEC") capacity presently used to power the U.S. uranium enrichment plant in Portsmouth, Ohio, might become available to AEP if that facility were to close. AEP/Kentucky indicated its plans were very fluid and likely subject to change in the next few years because of continuing changes in the electric industry, but that it did not believe it could make any plans at the present time that were contingent upon having either the Rockport or OVEC capacity available as a future supply resource.

In response to questions from the AG, AEP/Kentucky acknowledged that its IRP did not give a great deal of emphasis to environmental issues. AEP/Kentucky stated that uncertainties regarding ongoing litigation over environmental requirements made incorporating such issues into its IRP fairly unpredictable. It also indicated that it would be re-evaluating environmental issues subsequent to the completion of the AEP-CSW merger, which was approved by the Federal Energy Regulatory Commission ("FERC") the day of the conference, but which still awaits final approval from the Securities and Exchange Commission.

The AG also raised questions regarding AEP/Kentucky's actual load growth having been less than its forecasted load growth and whether there might be inherent problems in AEP/Kentucky's forecasting models. AEP/Kentucky stated that it had been reviewing that situation and had not discovered any inherent problems with the models.

NREPC stated that AEP/Kentucky needed to be looking more closely at energy efficiency measures in conjunction with restructuring of the electric industry because there is expected to be a thriving energy efficiency industry in the future. NREPC stated that the IRP was deficient in the area of Demand-Side Management ("DSM") programs and that it appeared that AEP/Kentucky was more interested in minimizing costs rather than maximizing energy savings. AEP/Kentucky indicated that it wanted to offer energy efficiency measures to its customers, but not at the cost of raising customers' rates. NREPC stated that the long-term benefits of such measures would outweigh the short-term impacts of rate increases and that since supply-side options with potential rate impacts were included in the IRP, then demand-side options should not be slighted in the IRP because they had rate impacts. AEP/Kentucky stated that its low costs made many energy efficiency programs compare unfavorably with supply-side options, but that the inclusion of "undesignated resources" in its IRP meant that those resources could be either supply-side or demand-side options, depending on the circumstances existing at the time decisions had to be made regarding future resource options.

Staff inquired about the status of regulatory approvals regarding the AEP-CSW merger and about the status of the AEP/Kentucky customer survey that had been delayed being sent to customers in late 1999. AEP/Kentucky indicated that if the FERC approval was given as expected, the SEC approval was the only remaining approval to be obtained. AEP/Kentucky indicated that it would be sending out the customer survey about April 15, 2000, and that the survey had been expanded in some areas in comparison to the 1996 survey that had been previously provided in response to a Staff data request.

Staff asked if there were any recent developments of which AEP/Kentucky was aware regarding the plans of Dynegy Corp. to construct a merchant plant near AEP/Kentucky's Big Sandy Generating Station in Louisa, Kentucky. AEP/Kentucky was aware that Dynegy had obtained an option on land near its Big Sandy station, but was not aware of any other recent developments.

Staff mentioned AEP's 12 percent reserve margin used for capacity planning purposes and that this margin, per the IRP, was, to some extent, related to the reserves of neighboring utilities. Staff asked whether AEP/Kentucky had re-evaluated this reserve level in view of the fact that two its neighboring utilities, Louisville Gas and Electric Company and Kentucky Utilities, which had merged in 1997, had reduced the overall reserve margin they used for planning purposed to 12 percent from the higher reserve margins they had previously used as stand-alone companies. AEP/Kentucky indicated that this was an issue it was constantly reviewing on an ongoing basis and that it was aware that the recent trend across the electric industry was toward reduced reserve margins. Staff also asked about the projected availability factors included in the IRP and the reasons for why AEP/Kentucky was projecting availability factors that exceed the levels it had achieved historically. AEP/Kentucky stated that it expected higher availability factors due to improved maintenance technologies and an increased emphasis, on its part, on preventative maintenance.

The conference concluded with Staff reminding the parties that Intervenors could file any comments on the IRP by March 31, 2000, and that AEP/Kentucky could file any reply comments by April 17, 2000.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
FEB 08 2000
PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING REPORT OF THE KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER TO THE KENTUCKY PUBLIC SERVICE COMMISSION, OCTOBER, 1999	)))))	CASE NO. 99-437

KENTUCKY DIVISION OF ENERGY'S SECOND REQUEST FOR INFORMATION TO THE KENTUCKY POWER COMPANY

Comes the Natural Resources and Environmental Protection Cabinet, Division of Energy (KDOE), Intervenor herein, and makes the following second request for information for the purpose of evaluating the effectiveness of the proposed integrated resource plan (IRP):

1. During KDOE's participation in the DSM Collaborative, we do not recall the Collaborative being involved in the process of developing Kentucky Power Company's (KPCo) 1996 or 1999 IRP Reports to the Commission. Does KPCo believe that it might be beneficial to get the perspective of the Collaborative on aspects of IRP planning that relate to demand-side management? Please explain the response.

2. Please refer to KDOE's Request No. 8, 1st Set. We interpret the first sentence of the response to mean that 1994 was the last time AEP analyzed a wide range of DSM options and measures. If this interpretation is incorrect, please explain.

3. In responding to KDOE's Request No. 15, 1st Set, dealing with local integrated resource planning (LIRP), KPCo stated that it uses both system-wide and localized planning perspectives. The response then referred to page 3-7 of the 1999 IRP report. There is a sentence in the second full paragraph that relates to this topic: "Avoided costs for transmission and distribution, expressed in $/kW, were estimated based on historical and projected capital expenditures for general system development projects that are related to load growth."

To KDOE, this implies that KPCo uses system-wide average values for T&D costs when calculating avoided costs. If this is the procedure KPCo is using, it represents precisely the opposite of the LIRP concept. According to the E Source Strategic Issues Paper referenced in KDOE's Request No. 15, 1st Set, LIRP's early applications have been "at the project level to assist in targeting expensive T&D upgrade or expansion projects that might be deferrable. Once such projects are identified, LIRP methodology guides planners through a comprehensive technical and economic evaluation of the *local* alternatives to the specific targeted upgrade." (page 3, under "LIRP Defined," emphasis in original)

To paraphrase KDOE's Request No. 15, 1st Set, in more specific terms:

a. Did KPCo identify particularly expensive T&D upgrade or expansion projects that might be deferrable, and having identified such projects, conduct a comprehensive technical and economic evaluation of the local supply-side and demand-side alternatives to the specific targeted upgrades?

b. Does KPCo plan to use such an approach, also known as LIRP, in the future?

4. In responding to KDOE's Request No. 16, 1st Set, dealing with hookup fees, KPCo referred to the Company's schedule of Tariffs, as approved and on file with the Commission. The Tariff Library web page linked to the Commission's internet site appears to be

missing the relevant pages, and the recent relocation of the Commission's offices has made other methods of obtaining these pages from the Commission difficult.

a. Please provide a copy of the pages that specify how hookup fees are calculated for residential, commercial, and industrial customers.

b. Please explain the economic rationale that underlies the hookup fee formulas now in effect.

5. KDOE's Request No. 17, 1st Set, asked about cofiring coal with sawdust at low percentages. In its response, KPCo raised two concerns: whether enough sawdust (biomass) would be available, and the economics – whether the biomass could be purchased cheaply enough and whether costly modifications would need to be made to the power plants.

a. Was AEP aware that at several power plants in the Southeast, cofiring of coal with limited percentages of sawdust has been accomplished in a cost-effective manner?

b. Would the availability of sawdust at very low or zero cost affect AEP's conclusions about the economics?

c. Were the economic benefits that could accrue to the forest products industry [i.e., avoided waste disposal costs] factored into AEP's preliminary evaluations of biomass cofiring? If not, why not?

6. In its Joint Integrated Resource Plan, submitted to the Commission on November 22, 1999, LG&E/KU found it advantageous to include the following demand-side programs [among others]:

- Direct load control of residential and commercial central air conditioners and water heaters and residential swimming pool pumps – 110.7 MW, with the first phase of 22.1 MW occurring in 2001 and with four comparable additional phases in the years 2002 to 2005;

- A special rate to enable the utility to use standby generation resources of participating commercial and industrial customers during peak load periods – 82.4 MW, with the first phase of 20.6 MW in 2002 and with three comparable phases in subsequent years (Reference: Case No. 99-430, Volume III, Sections IV and VII).

Has KPCo considered the potential net economic benefits that could accrue both to customers and shareholders by giving the utility some degree of influence or control over the energy use of participating customers during peak load periods, as programs such as those described above attempt to do?

7. Net metering has been instituted in some 30 states, and has been proposed to take effect on a national level through legislation titled the "Home Energy Generation Act," introduced by U.S. Representative Jay Inslee. Potential advantages of net metering include encouraging distributed generation, increasing the diversity of generation sources, reducing line losses, and reducing overall system costs if the customer-generator produces power during peak periods [e.g., a customer-owned photovoltaic system that produces at maximum output on a hot, sunny summer day].

a. If net metering were to be instituted on a national or statewide level, what would be the estimated impact on energy use and demand in the KPCo service area over the next 20 years?

b. Has KPCo considered proposing a net metering policy or tariff?

8. To what extent has KPCo encouraged the installation of combined heat and power (cogeneration) systems by industrial firms in its service area? Please provide quantitative information if available.

Respectfully submitted,

IRIS SKIDMORE
RONALD P. MILLS
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, Kentucky 40601
Telephone: (502) 564-6676

COUNSEL FOR NATURAL RESOURCES
AND ENVIRONMENTAL PROTECTION

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing KENTUCKY DIVISION OF ENERGY'S SECOND REQUEST FOR INFORMATION TO THE KENTUCKY POWER COMPANY was mailed, first class, postage prepaid, the 8th day of February, 2000, to the following:

Mr. Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
1701 Central Avenue
P.O. Box 1428
Ashland, Kentucky 41105-1428

Hon. Judith A. Villines
Hon. Bruce F. Clark
Attorney at Law
Stites & Harbison
P.O. Box 634
Frankfort, Kentucky 40602

Hon. Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601

Hon. David F. Boehm
Hon. Michael L. Kurtz
Boehm, Kurtz & Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, Ohio 45202

Iris Skidmore

ri-2nd-american electric-is-2-00

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN RE THE MATTER OF:

THE INTEGRATED RESOURCE PLANNING REPORT)
OF KENTUCKY POWER COMPANY d/b/a AMERICAN) Case No. 99-437
ELECTRIC POWER COMPANY)

THE ATTORNEY GENERAL'S
SUPPLEMENTAL REQUESTS FOR INFORMATION

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office for Rate Intervention, and submits these Requests for Information to Delta Natural Gas Company, Inc., to be answered in accord with the following:

(1) In each case where a request seeks data provided in response to a staff request, reference to the appropriate request item will be deemed a satisfactory response.

(2) Please identify the company witness who will be prepared to answer questions concerning each request.

(3) These requests shall be deemed continuing so as to require further and supplemental responses if the company receives or generates additional information within the scope of these requests between the time of the response and the time of any hearing conducted hereon.

(4) If any request appears confusing, please request clarification directly from the Office of Attorney General.

(5) To the extent that the specific document, workpaper or information as requested does not exist, but a similar document, workpaper or information does exist, provide the similar document, workpaper, or information.

(6) To the extent that any request may be answered by way of a computer printout, please identify each variable contained in the printout which would not be self evident to a person not familiar with

the printout.

(7) If the company has objections to any request on the grounds that the requested information is proprietary in nature, or for any other reason, please notify the Office of the Attorney General as soon as possible.

(8) For any document withheld on the basis of privilege, state the following: date; author; addressee; indicated or blind copies; all persons to whom distributed, shown, or explained; and, the nature and legal basis for the privilege asserted.

(9) In the event any document called for has been destroyed or transferred beyond the control of the company state: the identity of the person by whom it was destroyed or transferred, and the person authorizing the destruction or transfer; the time, place, and method of destruction or transfer; and, the reason(s) for its destruction or transfer. If destroyed or disposed of by operation of a retention policy, state the retention policy.

Respectfully Submitted,

/s/ Blackford

ELIZABETH E. BLACKFORD
ASSISTANT ATTORNEY GENERAL
1024 CAPITAL CENTER DRIVE
FRANKFORT KY 40601
(502) 696-5453
FAX: (502) 573-4814

NOTICE OF FILING AND CERTIFICATE OF SERVICE

I hereby give notice that the original and ten copies of the foregoing were filed this the 7th day of February, 2000, with the Kentucky Public Service Commission at 211 Sower Blvd., Frankfort, Kentucky, 40601, and certify that on this same date true copies were served on the parties by mailing same, postage prepaid to:

Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
P. O. Box 1428
Ashland, KY. 41105 1428

Honorable Judith A. Villines
Stites & Harbison
P. O. Box 634
Frankfort, KY. 40602 0634

John Stapleton

Director of Energy
Natural Resources and Environmental Protection
663 Teton Trail
Frankfort, KY. 40601

SUPPLEMENTAL DATA REQUESTS OF THE ATTORNEY GENERAL

1. Follow-up to Item 2. For each of the last 5 years please provide:

a) Kilowatt-hours sold off-system by Kentucky Power to other AEP companies.

b) Kilowatt-hours sold off-system by Kentucky Power to non-affiliated companies.

c) Kilowatt-hours purchased by Kentucky Power from other AEP companies.

d) Kilowatt-hours purchased by Kentucky Power from non-affiliated companies.

e) If Kentucky Power looses its Rockport capacity in 2005 and this capacity is replaced with peaking units as called for in the IRP, please quantify how this will affect Kentucky Power's off-system purchases and sales, assuming the load levels contained in the IRP.

2. Follow-up to Items 7 and 8. The preliminary CO2 emissions in 1999 were 120 million of tons. The projected CO2 emissions for 2000 are 131 millions of tons. Please explain this apparent increase of 9% between 1999 and 2000.

3. Follow-up to Item 10. For each of the past 10 years, please provide the number of tons of coal and MCF of gas used by Kentucky Power, as reported in the annual FERC Form 1.

4. Follow-up to PSC Item 2. Please explain in detail how Kentucky Power and the other AEP companies operating under the AEP Interconnection Agreement, will be affected by joint dispatch with CSW, if the AEP-CSW system is jointly dispatched? Will the AEP Interconnection Agreement need to be amended?

5. Follow-up to KDOE Item 17. This response mentions two concerns and a preliminary evaluation that shows this technology does not appear to be economically viable. Given the volume of sawdust readily available from sawmills in eastern Kentucky, please provide the evaluation that lead to the conclusion that the technology was not economically viable.

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Paul E. Patton
Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Martin J. Huelsmann
Executive Director
Public Service Commission

CERTIFICATE OF SERVICE

RE: Case No. 99-437
Kentucky Power Company d/b/a American Electric Power

I, Stephanie Bell, Secretary of the Public Service Commission, hereby certify that the enclosed copy of the Commission Staff's data request in the above case was served upon the following by U.S. Mail on February 9, 2000.

Parties:

Mr. Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
1701 Central Avenue
P.O. Box 1428
Ashland, Kentucky 41105-1428

Ms. Elizabeth Blackford
Assistant Attorney General
Division of Rate Intervention
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Frankfort, Kentucky 40402-2000

Ms. Iris Skidmore
Counsel for Natural Resources
And Environmental Protection
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Mr. John Stapleton
Division of Energy
663 Teton Trail
Frankfort, Kentucky 40601

Stephanie J. Bell
Secretary of the Commission

Enclosure

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Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Martin J. Huelsmann
Executive Director
Public Service Commission

February 8, 2000

Mr. Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
1701 Central Avenue
P.O. Box 1428
Ashland, Kentucky 41105-1428

RE: Case No. 99-437
Kentucky Power Company d/b/a American Electric Power

Enclosed is one copy of the Commission Staff's supplemental information request in the above case.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

Enclosure

EDUCATION PAYS

COMMONWEALTH OF KENTCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INTEGRATED RESOURCE PLANNING REPORT OF KENTUCKY POWER COMPANY d/b/a AMERICAN ELECTRIC POWER TO THE KENTUCKY PUBLIC COMMISSION, OCTOBER, 1999	)))	CASE NO. 99-437

COMMISSION STAFF'S SUPPLEMENTALREQUEST FOR INFORMATION TO KENTUCKY POWER COMPANY – AMERICAN ELECTRIC POWER

The Commission Staff requests that an original and 6 copies of the following information be provided to the Staff, with a copy to all parties of record, by no later than the due date set out in the procedural schedule previously established for this case. Each copy of the data requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 5. Include with each response the name of the person responsible for responding to questions relating to the information provided.

1. Refer to the response to Item 4 of the Staff's initial information request which indicates that the forecasting service provided by DRI was significantly more expensive than the RFA forecasting service. Provide the savings realized by AEP as a result of switching from DRI to RFA and show the portion of that savings allocated to or realized by Kentucky Power.

2. Refer to the response to Item 7 of the Staff' initial information request which indicates that, among other things, cost was one of the reasons for switching from an AEP-produced regional economic forecast to the forecast developed by Woods & Poole. Identify the amount of cost savings realized as a result of this change and the portion of the savings allocated to or realized by Kentucky Power.

3. Refer to the attachment to the response to Item 9 of the Staff's initial information request, where a number of binary variables are included in the regression equations. Explain the significance of each of the years chosen as binary variables.

4. Refer to the response to Item 13, part C, of the Staff's initial information request, where it is stated that "Such a short term energy requirements forecast has not been developed and, therefore, the requested results are not available". Given that the long-term forecasting models include incomes and energy prices (stated on page 2-2) as regressors, explain why a short-term energy requirements forecast has not been developed to include these variables.

5. Refer to the response to Item 14 of the Staff's initial information request.

   a. Part (a) states that "The requested re-estimation has never been developed and, therefore, cannot be provided." If this is so, explain why some of the short-term models are estimated via Proc Autoreg and the Yule-Walker method (also known as Prais-Winsten), which SAS is capable of performing.

b. In the response to part b, it is stated that "A low Durbin-Watson statistic is a well-known symptom ... of specification problems such as omitted variables." Given this, explain why no income variable was included in the USE equation.

6. Refer to the response to Item 15 of the Staff's initial information request. Explain why there currently is little need for modeling forecasts by major SIC codes as was done in previous IRPs.

7. Refer to the attachment to the response to Item 25 of the Staff's initial information request concerning average on-peak equivalent availability factors ("EAF").

   a. Regarding AEP-operated fossil steam units, identify the factors which caused the annual EAF to increase to 84 percent in 1996 when it had not exceeded 79.8 percent during any of the six previous years.

   b. After reaching 85.5 percent in 1997, the annual EAF for AEP-operated steam units declined slightly in each of the two following years, reaching 82.2 percent in 1999. Given this history, explain in detail the basis for projected EAF ranging from 86.2 to 88.1 percent throughout the forecast period.

8. Refer to the response to Item 28 of the Staff's initial information request regarding the mix of contract and spot coal purchases by AEP. For the contract purchases for the last three years shown (1996-1998), provide the following information:

   a. Tons mined – by state of origin.

   b. Tons by type, i.e. – low sulfur, medium sulfur, high sulfur, etc.

   c. Tons purchased - by AEP operating company.

9. Refer to the response to Item 29 of the Staff's initial information request.

   a. Provide the cost incurred for the dual-fuel capability modification of Conesville Units 1-3 as part of AEP's compliance plan.

   b. Identify the emission reductions that have been realized as a result of the modifications of these units to enable them to burn an alternative fuel.

   c. Given the results with these units, identify the extent to which similar modifications at other units might be included as part of AEP's future compliance plans.

Respectfully submitted.

Richard G. Raff

Richard G. Raff
Staff Attorney

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

December 29, 1999

To: All parties of record

RE: Case No. 1999-437

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
1701 Central Avenue
P. O. Box 1428
Ashland, KY 41105 1428

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1024 Capital Center Drive
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Honorable David F. Boehm
Honorable Michael L. Kurtz
Boehm, Kurtz & Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, OH 45202

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING REPORT OF KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER COMPANY	)))	CASE NO. 99-437

O R D E R

On December 16, 1999, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"), filed his Initial Information Requests in this proceeding, along with a Motion for an Extension of Time in which to file such requests. The AG states that he was unaware of the procedural schedule established for this proceeding until receiving the Commission Staff's Initial Data Request dated December 9, 1999.

The AG proposes that Kentucky Power Company d/b/a American Electric Power Company ("KPC/AEP") be permitted until January 24, 2000 to respond to the AG's information request, rather than January 13, 2000 as set out in the procedural schedule. The AG proposes to issue any supplemental information requests by February 8, 2000 as set out in the procedural schedule so that the procedural schedule may thereafter be maintained as it presently exists.

The AG asserts that he has spoken with KPC/AEP and its Counsel and that the AG has permission to represent to the Commission that KPC/AEP has no objections to the AG's request for an extension of time as described in the AG's motion of December 16, 1999.

On December 20, 1999, the Kentucky Natural Resources and Environmental Protection Cabinet, Department for Natural Resources, through its Division of Energy ("KDOE"), filed its Initial Information Requests in this proceeding, along with a Motion for an Extension of Time in which to file such requests. KDOE states that it was unaware of the procedural schedule established for this proceeding until receiving the AG's Initial Data Request dated December 16, 1999.

KDOE proposes that KPC/AEP be permitted until January 26, 2000 to respond to its initial information request, rather than January 13, 2000 as set out in the procedural schedule. KDOE and the AG propose to issue any supplemental information requests by February 8, 2000, as set out in the procedural schedule so that the procedural schedule may thereafter be maintained as it presently exists.

KDOE asserts that its Counsel has spoken with Counsel for KPC/AEP and that KPC/AEP has agreed to KDOE's request for an extension of time as described in its motion of December 20, 1999.

Having considered the motion and the constraints of the existing procedural schedule, and being otherwise sufficiently advised, the Commission finds that:

1. The AG's request for an extension of time to December 16, 1999 to file initial requests for information to KPC/AEP is reasonable and should be granted.

2. KDOE's request for an extension of time to December 20, 1999 to file initial requests for information to KPC/AEP is reasonable and should be granted.

3. KPC/AEP's responses to the AG's initial data requests shall be filed no later than January 24, 2000 and its responses to KDOE's initial data requests shall be filed no later than January 26, 2000.

IT IS THEREFORE ORDERED that:

1. The AG's request for an extension of time of seven days from the date set out in the procedural schedule, until December 16, 1999, to issue his initial requests for information to KPC/AEP is granted.

2. The AG's proposal to extend KPC/AEP's response date to its initial requests for information to January 24, 2000 is granted.

3. KDOE's request for an extension of time of eleven days from the date set out in the procedural schedule, until December 20, 1999, to issue its initial requests for information to KCP/AEP is granted.

4. KDOE's proposal to extend KPC/AEP's response date to its initial requests for information to January 26, 2000 is granted.

Done at Frankfort, Kentucky, this 29th day of December, 1999.

By the Commission

ATTEST:

Helen C. Helton

Executive Director

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
DEC 20 1999
PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING REPORT OF THE KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER TO THE KENTUCKY PUBLIC SERVICE COMMISSION, OCTOBER, 1999	)	**CASE NO. 99-437**

MOTION FOR EXTENSION OF TIME

Comes the Natural Resources and Environmental Protection Cabinet, Department for Natural Resources, Division of Energy (hereinafter KDOE), Intervenor herein, and moves the Commission to grant it an extension of time to and including December 20, 1999, in which to file the initial data request submitted herewith. In support of this motion, the KDOE states as follows:

1. On November 5, 1999, an employee of the Natural Resources and Environmental Protection Cabinet's Office of Legal Services examined the Commission's official public file for this matter.

2. On November 15, 1999, the Commission entered a procedural schedule setting a deadline of December 9, 1999 for filing initial interrogatories.

3. On November 16, 1999, the KDOE filed its motion to intervene in this proceeding. Since the KDOE filed its motion to intervene after the entry of the procedural schedule, the procedural schedule was not served on the KDOE.

4. On November 23, 1999, the Commission entered an order granting the KDOE's motion to intervene. This order made no reference to the procedural schedule. In addition,

although the order was served on John Stapleton, Director of the KDOE, the order was not served on counsel for the KDOE.

5. On December 17, 1999, counsel for the KDOE first became aware of the scheduling order when the KDOE was served with a copy of the motion of the Attorney General for an extension of time to file its initial data requests.

6. Counsel for the KDOE has spoken to counsel for Kentucky Power Company d/b/a American Electric Power Company and has permission to represent that the Company does not object to this motion for an extension of time.

7. Counsel for the KDOE and for Kentucky Power Company d/b/a American Electric Power Company and have also agreed that the company should have until January 26, 2000 to respond to KDOE's initial data requests. KDOE will send any supplemental requests no later than February 8, 2000, in accordance with the procedural schedule, so that the schedule may thereafter be maintained as written.

WHEREFORE, the KDOE moves the Commission for the entry of an order granting it an extension of time to file its initial data requests.

Respectfully submitted,

Ronald P. Mills

IRIS SKIDMORE
RONALD P. MILLS
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, Kentucky 40601
Telephone: (502) 564-6676

COUNSEL FOR NATURAL RESOURCES
AND ENVIRONMENTAL PROTECTION

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing MOTION FOR EXTENSION OF TIME was mailed, first class, postage prepaid, the 20th day of December, 1999, to the following:

Mr. Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
1701 Central Avenue
P.O. Box 1428
Ashland, Kentucky 41105-1428

Hon. Judith A. Villines
Attorney at Law
Stites & Harbison
P.O. Box 634
Frankfort, Kentucky 40602

Hon. Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601

Hon. David F. Boehm
Hon. Michael L. Kurtz
Boehm, Kurtz & Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, Ohio 45202

Ronald P. Mills

Ronald P. Mills

met-kypower-rpm1299

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING REPORT OF THE KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER TO THE KENTUCKY PUBLIC SERVICE COMMISSION, OCTOBER, 1999	)))))	**CASE NO. 99-437**

KENTUCKY DIVISION OF ENERGY'S FIRST REQUEST FOR INFORMATION TO THE KENTUCKY POWER COMPANY

Comes the Natural Resources and Environmental Protection Cabinet, Division of Energy, Intervenor, herein, and makes the following request for information for the purpose of evaluating the effectiveness of the proposed integrated resource plan (IRP):

1. In its February, 1994 report on the 1993 integrated resource plans of the major jurisdictional electric utilities in Kentucky, the staff of the Kentucky Public Service Commission (PSC) noted at page ES-2 that there are two methods of forecasting loads, econometric based load forecasting and end-use forecasting. According to the report, "End use forecasting allows for more explicit treatment of efficiency improvements and relies on explicit forecasts of saturation and unit energy consumption estimates, which can then be used in screening and planning DSM programs." No advantages for econometric based forecasting were cited. In developing its load forecast (1999, Section 2), did the Kentucky Power Company (KPCo) consider using end-use forecasting? Please explain why or why not.

2. On page 2-11, KPCo states that "No explicit adjustments were made to the forecast to account for national appliance efficiency standards or the National Energy Policy Act of 1992." Is this statement equivalent to an assumption that these governmental actions will not affect the trend in energy efficiency one way or the other? Please explain the response. If KPCo *had* decided to make explicit adjustments to account for these governmental actions, how would the adjustments have been applied to the model?

3. In developing its IRP, did KPCo perform a study to estimate the total quantity of demand-side energy efficiency and load shifting measures that would be available within its service area (i.e., a technical potential study), the cost of implementing such measures, and the revenue requirements that would be needed to acquire various portions of these potential resources through DSM programs?

4. Did KPCo estimate the square footage of residential, commercial, and industrial floor space that is being newly constructed each year in its service area? If so, what are the estimated square footage figures?

5. Did KPCo survey the energy efficiency of the new buildings being constructed in its service area? If so, please provide the results of this analysis.

6. Has KPCo availed itself of information from organizations such as E-Source, which is a source of comprehensive information on energy efficiency technologies and programs? To what extent, if any, was information from such sources used in developing the IRP?

7. On page 3-2, the IRP notes, "Increasing appliance efficiency standards and years of customer educational programs will make energy efficiency the normal practice in the future." A similar statement is made on page 3-5.

a. Please describe the scope of these customer education programs, as well as any estimates that KPCo may have made of their impacts on customers' behavior and on energy use.

b. Does KPCo believe that the normal operation of market forces (i.e., Adam Smith's "Invisible Hand") will cause customers to implement all energy efficiency measures that are cost effective?

c. Does KPCo believe there are significant market barriers that act to prevent customers from implementing all the energy efficiency measures that would be cost effective?

8. When was the last time AEP performed an extensive analysis on a wide range of DSM options, or measures, as discussed in the second paragraph of Section D on page 3-5? Were the results of this analysis shared with the KPCo DSM Collaborative?

9. The next paragraph on page 3-5 states that "In the case of KPCo, the DSM Collaborative, since its inception in November 1994, has been the decision-maker on the program screening process." A similar statement is made on page 3-6: "In this regard, the Collaborative continues to be the decision-maker on the DSM program-screening process and governs which DSM programs are to be screened for potential implementation in KPCo's service territory."

a. Aside from the Collaborative, which other organizational units or employees, if any, within KPCo or AEP have been assigned to develop new DSM program ideas for the KPCo service territory?

b. Did KPCo ever inform the DSM Collaborative that the Collaborative was the decision-maker on the program screening process? If so, approximately when?

c. Did KPCo ever describe to the DSM Collaborative just what tasks and responsibilities go along with being the decision-maker on the program screening process? If so, approximately when?

d. What resources, if any, has KPCo made available to the Collaborative to enable the Collaborative to carry out its responsibilities as the decision-maker on the program screening process? [for example, budget to develop new DSM program ideas, access to expert consultants, training, etc.]

e. To what degree has KPCo been open to suggestions for new DSM programs brought up by members of the Collaborative?

10. Whose conclusion was it that "in anticipation of deregulation, the emphasis of the DSM evaluation process has been shifted from a societal perspective, as reflected in the Total Resource Cost (TRC) test, to the ratepayer perspective, as reflected in the Ratepayer Impact Measure (RIM) test" [page 3-5], the Collaborative's or KPCo's? If it was a conclusion of the Collaborative, please provide a copy of the minutes of the meeting where this conclusion was reached.

11. Please describe in more detail how "the uncertainties regarding (a) customer choice of energy supplier in the future and (b) DSM cost-recovery mechanisms in the AEP System's different state jurisdictions serve to hinder the effectiveness and meaningfulness of the DSM evaluation process" [page 3-6].

12. On page 3-6, the IRP states that "The Collaborative has re-screened and re-evaluated the DSM programs originally filed for approval with the Commission in September 1995 and implemented in January 1996."

a. What does the word "re-screened" mean in this context? Does it mean anything more than "re-evaluated"?

b. Has KPCo ever asked the Collaborative to screen "a wide range of DSM options or measures", other than these existing programs? If so, please provide the approximate dates, and the "long list" of DSM options and measures considered.

13. When deciding on the set of DSM programs to recommend for implementation, did KPCo consider "the extent to which the plan provides programs which are available, affordable, and useful to all customers" [Reference KRS 278.285 (1)(g)]? Please discuss the degree to which the set of recommended DSM programs meets this statutory criterion.

14. Exhibit 3-3 projects that DSM impacts will level off and then decline over time. Has KPCo considered the possibility that technological advances in demand-side technology will continue to open new opportunities for cost-effective energy efficiency improvements?

15. The method of local integrated resource planning (LIRP), as described in a strategic issues paper by E-Source (1995) titled, "Local Integrated Resource Planning: A New Tool for a Competitive Era," is designed to determine if costs could be reduced by deferring transmission and distribution upgrades through the use of geographically-focused demand-side programs. [Other names for LIRP include "targeted area planning," "local area

investment planning," "distributed resources planning," or "area wide asset and customer service."]

a. Did KPCo use the LIRP approach to determine whether any planned transmission or distribution projects could economically be deferred? If so, please provide the results of the studies.

b. Does KPCo plan to use the LIRP approach in the future?

16. Please provide a detailed description of the method KPCo uses to determine how much to charge a new residential, commercial, or industrial customer to hook up their building to the grid. Please explain why this particular method or formula was chosen.

17. Did KPCo evaluate the cofiring of coal with sawdust at low percentages (e.g., less than 2 or 3 percent sawdust by weight) at existing coal-fired plants, which would provide a valuable service for the sawmill operations located in or near KPCo' service territory and also would reduce SO_2 emissions? Please explain the response.

Respectfully submitted,

Ronald P. Mills

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RONALD P. MILLS
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, Kentucky 40601
Telephone: (502) 564-6676

COUNSEL FOR NATURAL RESOURCES
AND ENVIRONMENTAL PROTECTION

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing KENTUCKY DIVISION OF ENERGY'S FIRST REQUEST FOR INFORMATION TO THE KENTUCKY POWER COMPANY was mailed, first class, postage prepaid, the 20th day of December, 1999, to the following:

Mr. Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
1701 Central Avenue
P.O. Box 1428
Ashland, Kentucky 41105-1428

Hon. Judith A. Villines
Attorney at Law
Stites & Harbison
P.O. Box 634
Frankfort, Kentucky 40602

Hon. Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601

Hon. David F. Boehm
Hon. Michael L. Kurtz
Boehm, Kurtz & Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, Ohio 45202

Ronald P. Mills

Ronald P. Mills

ri-kypower-rpm1299

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
DEC 1 6 1999
PUBLIC SERVICE COMMISSION

IN RE THE MATTER OF:

THE INTEGRATED RESOURCE PLANNING REPORT)
OF KENTUCKY POWER COMPANY d/b/a AMERICAN) Case No. 99-437
ELECTRIC POWER COMPANY)

THE ATTORNEY GENERAL'S
INITIAL REQUESTS FOR INFORMATION

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office for Rate Intervention, and submits these Requests for Information to Delta Natural Gas Company, Inc., to be answered in accord with the following:

(1) In each case where a request seeks data provided in response to a staff request, reference to the appropriate request item will be deemed a satisfactory response.

(2) Please identify the company witness who will be prepared to answer questions concerning each request.

(3) These requests shall be deemed continuing so as to require further and supplemental responses if the company receives or generates additional information within the scope of these requests between the time of the response and the time of any hearing conducted hereon.

(4) If any request appears confusing, please request clarification directly from the Office of Attorney General.

(5) To the extent that the specific document, workpaper or information as requested does not exist, but a similar document, workpaper or information does exist, provide the similar document, workpaper, or information.

(6) To the extent that any request may be answered by way of a computer printout, please identify each variable contained in the printout which would not be self evident to a person not familiar

with the printout.

(7) If the company has objections to any request on the grounds that the requested information is proprietary in nature, or for any other reason, please notify the Office of the Attorney General as soon as possible.

(8) For any document withheld on the basis of privilege, state the following: date; author; addressee; indicated or blind copies; all persons to whom distributed, shown, or explained; and, the nature and legal basis for the privilege asserted.

(9) In the event any document called for has been destroyed or transferred beyond the control of the company state: the identity of the person by whom it was destroyed or transferred, and the person authorizing the destruction or transfer; the time, place, and method of destruction or transfer; and, the reason(s) for its destruction or transfer. If destroyed or disposed of by operation of a retention policy, state the retention policy.

Respectfully Submitted,

ELIZABETH E. BLACKFORD
ASSISTANT ATTORNEY GENERAL
1024 CAPITAL CENTER DRIVE
FRANKFORT KY 40601
(502) 696-5453
FAX: (502) 573-4814

NOTICE OF FILING AND CERTIFICATE OF SERVICE

I hereby give notice that the original and ten copies of the foregoing were filed this the 16th day of December, 1999, with the Kentucky Public Service Commission at 730 Schenkel Lane, Frankfort, Kentucky, 40601, and certify that on this same date true copies were served on the parties by mailing same, postage prepaid to:

Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
P. O. Box 1428
Ashland, KY. 41105 1428

Honorable Judith A. Villines
Stites & Harbison
P. O. Box 634
Frankfort, KY. 40602 0634

John Stapleton
Director of Energy
Natural Resources and Environmental Protection
663 Teton Trail
Frankfort, KY. 40601

Attorney General's Initial Requests for Information

1. On page 1-1 of the IRP, reference is made to the need to add a Wyoming-Cloverdale 765-KV line. With respect to this planned addition:

a. Does any of this proposed line pass through Kentucky Power's service territory?

b. Will this project require a Certificate of Convenience and Necessity from the Public Service Commission of Kentucky? If so, when will the application be made?

c. Will Kentucky Power customers be charged for this new line in their rates? If yes, please indicate when and by what mechanism this charge will be added to rates.

2. With respect to the Rockport lease with Kentucky Power, discussed on page 1-9 of the IRP, please provide the following information for each of the last 5 years:

a. Amount of annual lease payment, and whether this amount will change if the agreement is renewed through 2004.

b. Number of kilowatt-hours produced by Kentucky Power's portion of the plant.

c. Number of kilowatt-hours produced, in part (b), that were actually used by Kentucky Power.

d. Number of kilowatt-hours produced, in part (b), that were sold to other AEP companies under the AEP Interconnection Agreement.

e. Number of kilowatt-hours produced, in part (b), that were sold to non-AEP affiliated companies.

f. Average fuel cost per kilowatt-hour.

g. Average non-fuel variable cost per kilowatt-hour.

h. Annual fixed O&M cost paid by Kentucky Power for its portion of the plant.

i. Total margin made in each given year for power from Kentucky Power's portion of Rockport sold to other AEP companies under the AEP Interconnection Agreement.

j. Total margin made in each given year for power from Kentucky Power's portion of Rockport sold to non-AEP affiliated companies.

k. If the Rockport lease agreement is not renewed in 2000 or 2005, what will AEP do with this capacity? Would not the capacity still be available to serve Kentucky Power under the AEP Interconnection Agreement?

3. On page 1-9 of the IRP reference is made to upcoming electric restructuring.

a. On December 15, 1999, the Kentucky Legislative Task Force on Electric Restructuring released its recommendation that Kentucky not pass any restructuring legislation during the next legislative session. Would Kentucky Power agree that there will be no electric restructuring in Kentucky in the near future and that Kentucky Power will continue under current regulation and will need to continue to plan to meet future load needs?

b. Please supply the status of any restructuring activities in each of the states in which AEP operates.

4. Table 5 on page 1-10 of the IRP shows that Kentucky Power, one of the smallest AEP companies, will be assigned the majority of the capacity 500 MW addition in 2005. Considering the lead time associated with building new capacity, including planning, is it the case that planning for this major addition to Kentucky Power's capacity will need to begin before Kentucky Power files its next IRP in 3 years.

5. On page 2-10 and 2-11 of the IRP, there is a discussion of how, when energy prices rise, customers respond by acting more energy efficiently. Nevertheless, the National Energy Policy Act of 1992 is being implemented during a period where electric prices are declining relative to inflation. Please explain in detail how your model can accommodate the reductions in energy use due to the National Energy Policy Act of 1992 when energy prices are declining.

6. Referring to Exhibit 2-30 in the IRP, please supply the actual data on this exhibit for calendar year 1999 for:

a. Kentucky Power Company's Recorded Summer Peak Load

b. Kentucky Power Company's Summer Peak Load - Weather Normalized

c. Kentucky Power Company's Recorded Winter Peak Load (through December 1999)

d. Kentucky Power Company's Winter Peak Load (through December 1999) - Weather Normalized

e. Kentucky Power Company's Recorded Energy

f. Kentucky Power Company's Energy - Weather Normalized

g. AEP System's Recorded Summer Peak Load

h. AEP System's Summer Peak Load - Weather Normalized

i. AEP System's Recorded Winter Peak Load (through December 1999)

j. AEP System's Winter Peak Load (through December 1999) - Weather Normalized

k. AEP System's Recorded Energy

l. AEP System's Energy - Weather Normalized

7. On page 3-7 of the IRP, it is stated that the evaluation Carbon Dioxide emissions was considered in the DSM evaluation. For each of the last 10 years, 1989-1999, please supply the following:

a. Total carbon dioxide emissions associated with supplying Kentucky Power's energy demand.

b. Total carbon dioxide emissions associated with supplying the internal energy demand for the total AEP System.

c. Total carbon dioxide emissions associated with supplying both the internal energy demand for the total AEP System and making off-system sales (AEP's total carbon dioxide emissions).

8. On page 3-7 of the IRP, it is stated that the evaluation Carbon Dioxide emissions was considered in the DSM evaluation. For each of the years in the IRP planning period, through 2019, and based on the plans in the IRP, please supply the following:

a. Total carbon dioxide emissions associated with supplying Kentucky Power's energy demand.

b. Total carbon dioxide emissions associated with supplying the internal energy demand for the total AEP System.

c. Total carbon dioxide emissions associated with supplying both the internal energy demand for the total AEP System and making off-system sales (AEP's total carbon dioxide emissions).

9. On page 4-8 of the IRP, reference is made to AEP subsidiaries' participation in the Ohio Valley Electric Corporation (OVEC). With respect to that participation, please supply the following:

a. Percent of participation and associated number of Megawatts for each of the 4 sponsoring AEP companies.

b. Number of Kilowatt-hours sold to OVEC by AEP for each of the last 5 years.

c. Number of Kilowatt-hours bought by OVEC from AEP for each of the last 5 years.

d. In December 1999, the United States Enrichment Corporation's President William Timbers stated that his company is "analyzing whether to shutting down one of its two production plants", and that upgrades were being made to the Paducah plant to match that capabilities of the Piketon plant. Has AEP included in the IRP the very real possibility that the Piketon plant may be shut down in the near future and that AEP's OVEC capacity may become available for AEP's use?

10. On page 4-15 of the IRP, coal and natural gas use is discussed. For each of the past 10 years 1989-1999, please supply:

a. Total tons of coal burned to supply Kentucky Power's energy demand.

b. Total tons of coal burned to supply the internal energy demand for the total AEP System.

c. Total tons of coal burned by AEP to supply both the internal energy demand for the total AEP System and make off-system sales.

d. Total MCF of natural gas burned to supply Kentucky Power's energy demand.

e. Total MCF of natural gas burned to supply the internal energy demand for the total AEP System.

f. Total MCF of natural gas burned by AEP to supply both the internal energy demand for the total AEP System and make off-system sales.

11. On page 4-15 of the IRP, coal and natural gas use is discussed. For each year of the IRP planning period (through 2019) and based on the plans in the IRP, please supply:

a. Total tons of coal projected to burned to supply Kentucky Power's energy demand.

b. Total tons of coal projected to burned to supply the internal energy demand for the total AEP System.

c. Total tons of coal projected to burned by AEP to supply both the internal energy demand for the total AEP System and make off-system sales.

d. Total MCF of natural gas projected to burned to supply Kentucky Power's energy demand.

e. Total MCF of natural gas projected to burned to supply the internal energy demand for the total AEP System.

f. Total MCF of natural gas projected to burned by AEP to supply both the internal energy demand for the total AEP System and make off-system sales.

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COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

December 17, 1999

To: All parties of record

RE: Case No. 1999-437

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie J. Bell

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
1701 Central Avenue
P. O. Box 1428
Ashland, KY 41105 1428

Honorable Judith A. Villines
Attorney at Law
Stites & Harbison
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Honorable Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY 40601

John Stapleton
Director of Energy
Natural Resources and Environmental
 Protection
663 Teton Trail
Frankfort, KY 40601

Honorable David F. Boehm
Honorable Michael L. Kurtz
Boehm, Kurtz & Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, OH 45202

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INTEGRATED RESOURCE PLANNING	)	
REPORT OF KENTUCKY POWER COMPANY	)	CASE NO.
D/B/A AMERICAN ELECTRIC POWER TO THE	)	99-437
KENTUCKY PUBLIC SERVICE COMMISSION,	)	
OCTOBER, 1999	)	

O R D E R

This matter arising upon the motion of the Kentucky Industrial Utility Customers, Inc. ("KIUC") for full intervention, and it appearing to the Commission that the KIUC has a special interest which is not otherwise adequately represented, and that such intervention is likely to present issues and develop facts that will assist the Commission in fully considering the matter without unduly complicating or disrupting the proceedings, and this Commission being otherwise sufficiently advised,

IT IS HEREBY ORDERED that:

1. The motion of the KIUC to intervene is granted.

2. The KIUC shall be entitled to the full rights of a party and shall be served with the Commission's Orders and with filed testimony, exhibits, pleadings, correspondence, and all other documents submitted by parties after the date of this Order.

3. Should the KIUC file documents of any kind with the Commission in the course of these proceedings, it shall also serve a copy of said documents on all other parties of record.

Done at Frankfort, Kentucky, this 17th day of December, 1999.

By the Commission

ATTEST:

Helen C. Helton

Executive Director

RECEIVED

DEC 16 1999

PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN RE THE MATTER OF:

THE INTEGRATED RESOURCE PLANNING REPORT)
OF KENTUCKY POWER COMPANY d/b/a AMERICAN) Case No. 99-437
ELECTRIC POWER COMPANY)

MOTION FOR EXTENSION OF TIME

Comes the Attorney General, and moves the Commission to grant it an extension of time to and including December 16th, 1999, in which to file the initial data requests submitted herewith. In support of this Motion the Attorney General states as follows:

1. The Motion to Intervene was made on the same day that the procedural schedule was entered. Accordingly the procedural schedule was not served on the Attorney General.

2. In the Order granting intervention, no reference was made to an existing procedural schedule. In the past, when the Attorney General has been granted the right to intervene after an procedural order was in place, the Order granting intervention has mentioned the existing procedural order in the course of advising the Attorney General that he would be expected to abide by that order.

3. The Attorney General became aware of the existence of the procedural schedule only upon his receipt on December 10, 1999, of the copy of the staff questions contained in the Order of date December 9, 1999.

4. The Attorney General has spoken with the Company and has agreed that the Company should to respond on January 24, 1999 (rather than on January 13, 1999, as is set out in the procedural schedule) so that the Company has the full time allotted in the procedural schedule to respond. The Attorney General will also send any supplemental requests on February 8, so that the procedural schedule may thereafter be maintained as now written.

5. Counsel has spoken with Counsel for Kentucky Power Company d/b/a American

Electric Power Company and has permission to represent to the Commission that the Company does not object to the request for an extension on the terms set out in paragraph 4.

ELIZABETH E. BLACKFORD
ASSISTANT ATTORNEY GENERAL
1024 CAPITAL CENTER DRIVE
FRANKFORT KY 40601
(502) 696-5453
FAX: (502) 573-4814

NOTICE OF FILING AND CERTIFICATE OF SERVICE

I hereby give notice that the original and ten copies of the foregoing were filed this the 16th day of December, 1999, with the Kentucky Public Service Commission at 730 Schenkel Lane, Frankfort, Kentucky, 40601, and certify that on this same date true copies were served on the parties by mailing same, postage prepaid to:

Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
P. O. Box 1428
Ashland, KY. 41105 1428

Honorable Judith A. Villines
Stites & Harbison
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Frankfort, KY. 40602 0634

John Stapleton
Director of Energy
Natural Resources and Environmental Protection
663 Teton Trail
Frankfort, KY. 40601

COMMONWEALTH OF KENTCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

DEC 0 9 1999

PUBLIC SERVICE COMMISSION

In the Matter of:

INTEGRATED RESOURCE PLANNING REPORT)
OF KENTUCKY POWER COMPANY d/b/a)
AMERICAN ELECTRIC POWER TO THE KENTUKY)
PUBLIC SERVICE COMMISSION, OCTOBER, 1999)

CASE NO. 99-437

COMMISSION STAFF'S REQUEST FOR INFORMATION TO KENTUCKY POWER COMPANY – AMERICAN ELECTRIC POWER

The Commission Staff requests that an original and 6 copies of the following information be provided to the Staff, with a copy to all parties of record, by no later than the due date set out in the procedural schedule previously established for this case. Each copy of the data requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 5. Include with each response the name of the person responsible for responding to questions relating to the information provided.

1. Refer to page 1-2 of the Executive Summary of the Integrated Resource Planning ("IRP") Report of Kentucky Power Company ("KPC") and American Electric Power ("AEP") submitted October 21, 1999. Provide the current status of the regulatory approvals, in all jurisdictions, of the proposed merger of AEP and Central and South West Corporation ("CSW").

2. Identify and describe the manner in which the combined AEP-CSW system would be dispatched if and when, the merger receives final approval.

3. Refer to page 1-3 of the Executive Summary of the IRP report. Provide the current status of the unit power agreement with AEP Generating Company to purchase 390 megawatts of capacity from the Rockport Plant.

4. Refer to page 1-4 of the Executive Summary. Explain the reasons for the decision to switch from relying on the economic forecast performed by RDI to the forecast performed by RFA.

5. Refer to pages 1-4 and 1-5 of the Executive Summary. Identify all the factors that cause the forecast growth in demand for KPC to exceed that of the AEP system as a whole.

6. Refer to pages 1-11 and 1-12 of the Executive Summary. Provide a summary of the experience, to date, of any of the AEP operating companies regarding customers taking service under the ECS and PCS tariffs that were recently implemented.

7. Refer to page 2-1 of the Load Forecast section of the report. Explain the reason for using the 1998 regional economic forecast developed by Woods & Poole Economics, Inc. when KPC had previously performed this function in-house.

8. KPC and AEP use short-term and long-term models in their forecasting processes, with the short-term models covering the first 5 years of the forecast period. Explain the basis for choosing 5 years as the appropriate "short-term' period. Would applying the short-term models to a longer 'short-term' period of time be more costly?

9. Refer to pages 2-2 and 2-3 of the Load Forecast section of the report. Provide the results from the models used by KPC / AEP to predict sectoral natural gas prices and regional coal production as inputs to the long-term energy forecasts.

10. Refer to page 2-4 of the Load Forecast section of the report. Provide a more detailed description of the FRB production index used in the forecast for the industrial sector. Specifically identify the results that were used by KPC as inputs into its forecasting models.

11. Refer to page 2-8 of the Load Forecast section of the report. Given the areas of eastern and southeastern Kentucky included in KPC's service territory, explain why the Huntington, West Virginia weather station is the only point used by KPC to reflect weather effects in its forecasting.

12. Refer to page 2-9 of the Load Forecast section of the report, specifically the sentence that states that weather effects are assumed to be zero at an average daily temperature of 62 degrees. Many gas and electric utilities use 65 degrees as the average temperature at which weather effects are assumed to be zero. Provide an explanation of how and why KPC developed and uses 62 degrees for this purpose.

13. Refer to page 2-11 of the Load Forecast section. It is stated that the monthly short–term load forecasting models do not include variables such as the price of energy or per capita income, even though economic theory states that demand is always a function of price and income. Given this, answer the following:

    a) In general, what are the expected signs of the coefficients of the variables included in each of the short–term forecasting equations?

    b) Do the estimated coefficients obtained in the regression procedures (listed in the Appendix) accord with a priori expectations in terms of signs and statistical significance?

    c) Given that: (1) the estimation results possibly reflect omitted variable bias; (2) there exists some probability that electric restructuring will occur in Kentucky within the next five years, which could be contrary to the assumption that prices will be held constant in nominal terms.

Provide the results of a short-term energy requirements forecast that includes the price of electricity, real per capita incomes, and any other customer – specific information variables that would be relevant in specifying these demand equations.

14. Concerning the Long – term forecasting models:

a) Given the apparent autocorrelation that exists in some of the models (e.g., USE, EIM_KPC, EL_KPC), provide a re-estimation of the long–term forecasting equations using a procedure which corrects for such autocorrelation (such as Cochrane – Orcutt or Prais – Winston, given the small sample size).

b) Explain why is it assumed that (as stated on page 2-6) "in these cases, apparent autocorrelation is more likely a symptom of specific problems stemming from such causes as errors in data or omitted variables than of autocorrelation"?

c) Explain if the negatively – signed intercepts yielded by the estimation procedures cause for concern (since they appear to be highly statistically significant). Why or why not?

15. Refer to page 2-15 of the Load Forecast section of the report. Explain the reasons for modeling the industrial sector in aggregate rather than by major SIC code as has been done in prior IRPs.

16. Refer to Exhibit 2-28 of the report. Manufacturing and Mine Power customers both declined during the period from 1994 through 1998. Explain how this decline is reflected in the industrial sector forecast.

17. Refer to Exhibit 2-32. Provide the 'data source' documents identified therein that KPC / AEP obtained from NOAA, RFA, and DOE/EIA.

18. Refer to page 3-3 of the DSM section of the report. Provide a more detailed description of the EPA Green Lights Program identified therein.

19. Refer to page 3-4 of the DSM section of the report. Provide the survey that has been, or will be, distributed to customers, along with the number of KPC customers receiving the survey, the total number of AEP customers receiving the survey, and an explanation for how the sample size was determined.

20. Refer to page 3-7 of the DSM section of the report. If no specific dollar amounts were assigned to reductions to CO_2 and NO_x emissions, explain how those reductions were included in the evaluation of DSM programs.

21. Refer to page 3-8 of the DSM section of the report. Provide the level of participation by KPC's customers in the Load Management Water Heating Program to date and identify any load impacts that can be directly attributed to the program.

22. Refer to page 3-9 of the DSM section of the report. Explain how and why the measure-screening and program-screening processes were combined in the 1999 DSM screening rather than being performed separately as has been done in prior screenings.

23. Refer to page 3-10 of the DSM section of the report, specifically Paragraph H.2. Provide a more thorough description and explanation of how increasing competition might affect DSM in the future and why the emphasis in future evaluations would be more from a ratepayer perspective than from a societal perspective.

24. Refer to page 4-6 of the Resource Forecast section of the report. Provide an explanation for the determination by AEP that a satisfactory level of capacity-deficient days is between 5 and 10% of the number of days in a year.

25. Refer to page 4-6 of the Resource Forecast section of the report. Provide support for the projection that AEP's average on-peak equivalent availability will be 80% or better during the forecast period. Provide the comparable equivalent availability data for the AEP system for the 10-year period from 1989 through 1998.

26. Refer to page 4-7 of the Resource Forecast section of the report. Provide a detailed explanation for the assumption that the unit power agreement between KPC and AEP Generating Company will expire at the end of 2004. Identify the factors that might lead to the contract being extended beyond 2004.

27. Refer to page 4-11 of the Resource Forecast section of the report, specifically the section dealing with non-utility generation. To what extent is KPC familiar with plans by Dynegy Corp. to construct a merchant plant near the site of its Big Sandy Generating Station? What consideration has been given to the potential construction of that plant?

28. Refer to page 4-15 of the Resource Forecast section of the report, specifically the statement that indicates that most of AEP's total coal requirements are obtained under long-term arrangements. Explain or define what is meant by 'most' and provide the split between contract and spot market purchases for the AEP system for each of the years from 1994 through 1998.

29. Refer to pages 4-15 and 4-16 of the Resource Forecast section of the report. Identify which of the AEP generating units have been modified in order to be dual-fuel capable as part of AEP's compliance plan.

30. Refer to Exhibit 4-10 of the report. The Big Sandy station has the lowest average production costs of all AEP generating capacity. Given the central dispatching of the AEP system, identify how much of KPC's load and energy requirements are served from KPC's own Big Sandy generating station.

31. Refer to Exhibit 4-10 of the report and KPC's firm purchases of energy from the Rockport plant as shown in Exhibit 4-23. Identify where the Big Sandy station and the Rockport station fall in the order of dispatch for the AEP system. Identify how much energy KPC is required to purchase under the unit power agreement on an annual basis. Explain how the determination is made as to what energy will be sold off-system and what energy will go toward serving KPC's native load customers.

32. Refer to Exhibit 4-11 of the report. Explain the basis for the different life expectancies (50 years, 60 years, and 70 years0) shown for the different generating units identified in the exhibit.

33. Refer to Exhibit 4-25 of the report which compares the AEP system's 1996 and 1999 expansion plans. Identify the factors that have contributed to the decrease in the amount of capacity expected to be added through 2016.

34. Refer to page 2 of the Appendix regarding Short-Term Energy Models. Explain why there are only two exogenous variables for cooling degree-days and three exogenous variables for heating degree-days.

35. Refer to page 62 of the Appendix showing residential customers, actual and forecast. For the period 1989 through 1998 the growth in the number of customers has averaged approximately 1.05%. Identify the factors that led to the forecast growth of only .8 to .9% and explain how those factors were used to produce the forecast growth rate.

36. Page 74 of the Appendix shows exogenous variables for the commercial sector. Given the similarities that residential and commercial customers have regarding temperature-sensitive load, explain why there are no temperature-sensitive variables for the commercial sector.

37. Refer to pages 90 and 91 of the Appendix that show the exogenous variables for the Mine Power sector. Service area coal production has remained almost flat over the period from 1989 through 1998. Identify the factors that support the forecasted increase in service area production and explain how those factors were used to derive the forecasted increase. Also, explain how the forecasted increase in service area mine production comports with the statement on page 2-14 of the report that references the continued shift of production from eastern to western states.

Respectively submitted,

Richard G. Raff
Richard G. Raff
Staff Attorney

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing Commission Staff's Request for Information to Kentucky Power Company was mailed, postage prepaid, this 9th day of December, 1999 to the following:

Elizabeth E. Blackford
Assistant Attorney General
Office for Rate Intervention
1024 Capital Center Drive
Frankfort, KY 40601

Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
1701 Central Avenue
P.O. Box 1428
Ashland, KY 41105 1428

Honorable Judith A. Villines
Attorney at Law
Stites & Harbison
421 West Main Street
P.O. Box 634
Frankfort, KY 40602 0634

John Stapleton
Director of Energy
Natural Resources and Environmental Protection
663 Teton Trail
Frankfort, KY 40601

Richard G. Raff

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

November 23, 1999

To: All parties of record

RE: Case No. 1999-437

We enclose one attested copy of the Commission's Orders in the above case.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosures

Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
1701 Central Avenue
P. O. Box 1428
Ashland, KY 41105 1428

Honorable Judity A. Villines
Attorney at Law
Stites & Harbison
421 West Main Street
P. O. Box 634
Frankfort, KY 40602 0634

Honorable Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY 40601

John Stapleton
Director of Energy
Natural Resources and Environmental
Protection
663 Teton Trail
Frankfort, KY 40601

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INTEGRATED RESOURCE PLANNING	)	
REPORT OF KENTUCKY POWER COMPANY	)	CASE NO.
D/B/A AMERICAN ELECTRIC POWER TO THE	)	99-437
KENTUCKY PUBLIC SERVICE COMMISSION,	)	
OCTOBER, 1999	)	

ORDER

This matter arising upon the motion of the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("Attorney General"), filed November 16, 1999, pursuant to KRS 367.150(8), for full intervention, such intervention being authorized by statute, and this Commission being otherwise sufficiently advised,

IT IS HEREBY ORDERED that the motion is granted, and the Attorney General is hereby made a party to these proceedings.

Done at Frankfort, Kentucky, this 23rd day of November, 1999.

By the Commission

ATTEST:

Helen C. Helton

Executive Director

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INTEGRATED RESOURCE PLANNING	)	
REPORT OF KENTUCKY POWER COMPANY	)	CASE NO.
D/B/A AMERICAN ELECTRIC POWER TO THE	)	99-437
KENTUCKY PUBLIC SERVICE COMMISSION,	)	
OCTOBER, 1999	)	

O R D E R

This matter arising upon the motion of the Kentucky Natural Resources and Environmental Protection Cabinet, Department for Natural Resources, through its Division of Energy ("NREPC"), filed November 16, 1999, for full intervention, and it appearing to the Commission that the NREPC has a special interest which is not otherwise adequately represented, and that such intervention is likely to present issues and develop facts that will assist the Commission in fully considering the matter without unduly complicating or disrupting the proceedings, and this Commission being otherwise sufficiently advised,

IT IS HEREBY ORDERED that:

1. The motion of the NREPC to intervene is granted.

2. The NREPC shall be entitled to the full rights of a party and shall be served with the Commission's Orders and with filed testimony, exhibits, pleadings, correspondence, and all other documents submitted by parties after the date of this Order.

3. Should the NREPC file documents of any kind with the Commission in the course of these proceedings, it shall also serve a copy of said documents on all other parties of record.

Done at Frankfort, Kentucky, this 23rd day of November, 1999.

By the Commission

ATTEST:

Executive Director

BOEHM, KURTZ & LOWRY
ATTORNEYS AT LAW
2110 CBLD CENTER
36 EAST SEVENTH STREET
CINCINNATI, OHIO 45202
TELEPHONE (513) 421-2255
TELECOPIER (513) 421-2764

VIA OVERNIGHT MAIL

November 19, 1999

Ms. Helen Helton
Executive Director
Kentucky Public Service Commission
730 Schenkel Lane
Frankfort, Kentucky 40601

Re: In The Matter Of: Integrated Resource Planning Report of Kentucky Power Company d/b/a American Electric Power to the Kentucky Public Service Commission, October, 1999, Case No. 99-437.

Dear Ms. Helton:

Please find enclosed the original and ten copies of the Petition to Intervene of Kentucky Industrial Utility Customers, Inc. in the above-referenced matter. By copy of this letter, all parties listed on the Certificate of Service have been served.

Please place this document of file.

Very Truly Yours,

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY

MLK/kew
Encl.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by mailing a true and correct copy, by first-class postage prepaid mail, unless otherwise noted, to all parties on this 19th day of November, 1999.

Hon. Bruce F. Clark
Hon. Judith A. Villines
Stites & Harbison
421 W. Main Street
Frankfort, KY 40601

Mr. Errol K. Wagner
American Electric Power Service Corporation
1701 Central Avenue
P.O. Box 1428
Ashland, KY 41101-1428

Hon. Elizabeth E. Blackford
Assistant Attorney General
Utility and Rate Intervention Division
P.O. Box 2000
Frankfort, KY 40602

Iris Skidmore, Esq.
Ronald P. Mills, Esq.
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 4601

Michael L. Kurtz, Esq.

RECEIVED
NOV 22 1999
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of: Integrated Resource Planning Report of Kentucky Power Company d/b/a American Electric Power To The Kentucky Public Service Commission, October, 1999	:	Case No. 99-437

PETITION TO INTERVENE OF KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

Pursuant to K.R.S. §278.310 and 807 KAR 5:001 Section 3(8), Kentucky Industrial Utility Customers, Inc. ("KIUC") requests that it be granted full intervenor status in the above-captioned proceeding and states in support thereof as follows:

1. KIUC is an association of the largest electric and gas public utility customers in Kentucky. The purpose of KIUC is to represent the industrial viewpoint on energy and utility issues before this Commission and before all other appropriate governmental bodies. The members of KIUC who will participate herein are: Marathon Ashland Petroleum LLC, Kentucky Electric Steel, AK Steel Corporation, and Inco Alloys.

2. The matters being decided by the Commission in this case may have a significant impact on the rates paid by KIUC for electricity. Electricity represents a significant cost of doing business for KIUC. The attorneys for KIUC authorized to represent them in this proceeding and to take service of all documents are:

David F. Boehm, Esq.
Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
2110 CBLD Center, 36 East Seventh Street
Cincinnati, Ohio 45202
Ph: (513) 421-2255, Fax: (513) 421-2765
E-Mail: KIUC@aol.com

3. The position of KIUC cannot be adequately represented by any existing party. KIUC intends to play a constructive role in the Commission's decision making process herein and KIUC's participation will not unduly prejudice any party.

WHEREFORE, KIUC requests that it be granted full intervenor status in the above captioned proceeding.

Respectfully submitted,

David F. Boehm, Esq.
Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
2110 CBLD Center
36 East Seventh Street
Cincinnati, Ohio 45202

Counsel for Kentucky Industrial Utility Customers, Inc.

November 19, 1999

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

NOV 1 6 1999

In the Matter of:

THE INTEGRATED RESOURCE PLANNING REPORT OF THE KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER TO THE KENTUCKY PUBLIC SERVICE COMMISSION, OCTOBER, 1999	)))))	**CASE NO. 99-437**

MOTION

Comes now the Kentucky Natural Resources and Environmental Protection Cabinet, Department for Natural Resources, through its Division of Energy, (hereinafter "NREPC"), by counsel, and pursuant to 807 KAR 5:001 Section 3(8), moves for leave to intervene in the above-styled case, and that it be granted full intervention status. In support of its motion, NREPC states as follows:

1. KRS 224.10-100(14) authorizes the NREPC to "advise, consult, and cooperate with other agencies of the Commonwealth";

2. KRS 224.10-100(28) authorizes the NREPC to "develop and implement programs for the development, conservation, and utilization of energy in a manner to meet human needs while maintaining Kentucky's economy at the highest feasible level";

3. The Division of Energy serves as the state energy office for Kentucky and administers a variety of programs designed to enhance the efficiency of energy production and use in all sectors of the economy;

4. In response to its legislative mandate, NREPC has worked for many years to maximize system-wide efficiency in the provision and use of electrical services through the mechanisms of integrated resource planning, least-cost planning, and demand-side management (DSM) programs offered through utility companies,

5. It has been the consistent goal of NREPC to minimize the total long-term societal costs of electric services;

6. If granted leave to intervene in this proceeding, NREPC can help ensure that the integrated resource plan filed by the Kentucky Power Company d/b/a American Electric Power is consistent with the goal of minimizing the total long-term societal costs of electric services in its service area within Kentucky;

7. The NREPC has a special interest in this proceeding, its interest is not otherwise adequately represented, and with full intervention status, the NREPC will present issues and develop facts that will assist the Commission in fully considering this matter;

8. The NREPC being granted full intervention status will not unduly complicate or disrupt these proceedings;

9. The person designated to represent the NREPC in this proceeding is its Director of Energy:

John Stapleton
663 Teton Trail
Frankfort, Kentucky 40601
Telephone: (502) 564-7192

WHEREFORE, the NREPC respectfully prays for an Order granting it full intervention in this matter.

Respectfully submitted,

IRIS SKIDMORE
RONALD P. MILLS
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, Kentucky 40601
Telephone: (502) 564-6676

COUNSEL FOR NATURAL RESOURCES
AND ENVIRONMENTAL PROTECTION

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing Motion was mailed, first class, postage prepaid, the 16th day of November, 1999, to the following:

Bruce F. Clark, Esq.
Judith A. Villines, Esq.
Stites & Harbison
P.O. Box 634
Frankfort, Kentucky 40602

David F. Boehm, Esq.
Boehm, Kurtz & Lowry
36 East Seventh Street
Cincinnati, Ohio 45202

Office of Attorney General
Division of Rate Intervention
P.O. Box 2000
Frankfort, Kentucky 40602-2000

Iris Skidmore

COMMONWEALTH OF KENTUCKY

BEFORE THE
PUBLIC SERVICE COMMISSION

RECEIVED
NOV 15 1999
PUBLIC SERVICE COMMISSION

IN RE THE MATTER OF:

THE INTEGRATED RESOURCE PLANNING REPORT)
OF KENTUCKY POWER COMPANY d/b/a AMERICAN) Case No. 99-437
ELECTRIC POWER COMPANY)

MOTION TO INTERVENE

Comes the Attorney General, A. B. Chandler, III, pursuant to KRS 367.150 (8) which grants him the right and obligation to appear before regulatory bodies of the Commonwealth of Kentucky to represent the consumers' interests, and moves the Public Service Commission to grant him full intervener status in this action pursuant to 807 KAR 5:001(8).

ELIZABETH E. BLACKFORD
ASSISTANT ATTORNEY GENERAL
1024 CAPITAL CENTER DRIVE
FRANKFORT KY 40601
(502) 696-5453
FAX: (502) 573-4814

NOTICE OF FILING AND CERTIFICATE OF SERVICE

I hereby give notice that the original and ten copies of the foregoing were filed this the 15th day of November, 1999, with the Kentucky Public Service Commission at 730 Schenkel Lane, Frankfort, Kentucky, 40601, and certify that on this same date true copies were served on the parties by mailing same, postage prepaid to:

Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
P. O. Box 1428
Ashland, KY. 41105 1428

Honorable Judith A. Villines
Stites & Harbison
P. O. Box 634
Frankfort, KY. 40602 0634

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

November 15, 1999

Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
1701 Central Avenue
P. O. Box 1428
Ashland, KY. 41105 1428

Honorable Judity A. Villines
Attorney at Law
Stites & Harbison
421 West Main Street
P. O. Box 634
Frankfort, KY. 40602 0634

RE: Case No. 99-437

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INTEGRATED RESOURCE PLANNING REPORT OF KENTUCKY POWER COMPANY d/b/a AMERICAN ELECTRIC POWER TO THE KENTUCKY PUBLIC SERVICE COMMISSION, OCTOBER, 1999	)))))	CASE NO. 99-437

ORDER

The Commission, on its own motion, hereby initiates its review of the Integrated Resource Plan ("IRP") of Kentucky Power Company d/b/a American Electric Power ("AEP") filed on October 21, 1999 pursuant to 807 KAR 5:058. AEP is required by 807 KAR 5:058, Section 10, to publish, in a form prescribed by the Commission, notice of its filing in a newspaper of general circulation in its service area. The notice must be published within 30 days of the filing date of the IRP. The Commission finds that the following format should be used when publishing notice of the IRP filing:

> On October 21, 1999, American Electric Power filed its 1999 Integrated Resource Plan with the Kentucky Public Service Commission. This filing includes American Electric Power's most recent load forecast and a description of the existing and planned conservation programs, load management programs and generating facilities AEP expects to use to meet its forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utility, and file written comments on the plan.
>
> Any person interested in participating in the review of this Integrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to: Helen C. Helton, Executive Director, Public Service Commission, P.O. Box 615, Frankfort, KY 40602.

The newspaper notice should be published as soon as reasonably possible after the receipt of this Order. The publication of this notice is in addition to AEP's responsibility under 807 KAR 5:058, Section 2(2), to provide notice, immediately upon filing its IRP, to intervenors in its last IRP proceeding, that its plan has been filed and is available from the utility upon request.

In addition to the notice requirements set forth above, the Commission, on its own motion, hereby adopts the schedule included in Appendix A, attached hereto and incorporated herein, which establishes the procedural dates for this proceeding. Pursuant to 807 KAR 5:058, Section 2(3), this schedule may include interrogatories, informal conferences, comments, and staff reports.

IT IS THEREFORE ORDERED that:

1. AEP shall publish the notice set forth herein as required by 807 KAR 5:058, Section 10.

2. The procedural schedule set forth in Appendix A, attached hereto and incorporated herein, shall be followed in this case.

Done at Frankfort, Kentucky, this 15th day of November, 1999.

By the Commission

ATTEST:

Helen C. Helton

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 99-437 DATED 11/15/99

Initial interrogatories to AEP shall be filed no later than 12/09/99

AEP's responses to initial interrogatories shall be filed no later than 01/13/00

Supplemental interrogatories to AEP shall be filed no later than 02/08/00

AEP's responses to supplemental interrogatories shall be filed no later than 02/29/00

An Informal Conference will be held at 10:00 a.m., Eastern Standard Time, in the Commission's offices at 211 Sower Boulevard, Frankfort, Kentucky, for the purpose of discussing issues related to AEP's 1999 IRP filing 03/15/00

Intervenors shall have the option of filing written comments on issues related to AEP's 1999 IRP filing no later than 03/31/00

AEP shall have the option to file written comments in reply to any written comments from intervenors no later than 04/17/00

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KENTUCKY 40602
www.psc.state.ky.us
(502) 564-3940

November 9, 1999

Judith A. Villines, Esq.
Stites & Harbison
421 West Main Street
Post Office Box 634
Frankfort, Kentucky 40602-0634

RE: American Electric Power
Petition for Confidential Protection
99-437

Dear Ms. Villines:

The Commission has received the petition of AEP filed October 21, 1999, to protect as confidential that projected cost data and retail rates in the supplemental reports portion of its October 21 report. A review of the information has determined that it is entitled to the protection requested on the grounds relied upon in the petition, and it shall be withheld from public inspection.

If the information becomes publicly available or no longer warrants confidential treatment, you are required by 807 KAR 5:001, Section 7(9)(a) to inform the Commission so that the information may be placed in the public record.

Sincerely,

Helen C. Helton

Helen C. Helton
Executive Director

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

October 22, 1999

Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
1701 Central Avenue
P. O. Box 1428
Ashland, KY. 41105 1428

Honorable Judity A. Villines
Attorney at Law
Stites & Harbison
421 West Main Street
P. O. Box 634
Frankfort, KY. 40602 0634

RE: Case No. 99-437
AMERICAN ELECTRIC POWER
(Integrated Resource Plan)

This letter is to acknowledge receipt of initial application in the above case. The application was date-stamped received October 21, 1999 and has been assigned Case No. 99-437. In all future correspondence or filings in connection with this case, please reference the above case number.

If you need further assistance, please contact my staff at 502/564-3940.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

SB/jc

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

OCT 21 1999

PUBLIC SERVICE COMMISSION

In the Matter of:

INTEGRATED RESOURCE PLANNING REPORT	)
OF KENTUCKY POWER COMPANY d/b/a	)
AMERICAN ELECTRIC POWER TO THE	)
KENTUCKY PUBLIC SERVICE COMMISSION,	)
OCTOBER, 1999	) Case 99-437

* * * * * * * *

MOTION FOR CONFIDENTIAL TREATMENT

Comes Kentucky Power Company d/b/a American Electric Power (hereinafter "AEP"), by and through counsel, and moves the Commission pursuant to 807 KAR 5:001, Section 7, for an Order granting confidential treatment to the proprietary supplement to AEP's Integrated Resource Planning Report submitted pursuant to 807 KAR 5:058 on October 21, 1999.

The above referenced report includes extensive information on AEP's future operations, including load forecast, DSM, resource forecast and the Company's IRP procedures. As a supplement to its October 21st Report, AEP has projected future fuel and operating and maintenance costs data, as well as future average retail electric rates which it might be allowed to charge by the Kentucky Public Service Commission under the current regulatory environment. However, as noted in the beginning of the Report on pages 1-2, sweeping regulatory and legislative changes are underway in the electric utility industry, so the traditional concepts of utility ratemaking, and on which the Report is premised, may well prove invalid over time. Because of these changes, and the accompanying uncertainty, AEP seeks confidential protection for the supplemental portion of its October 21st Report, which refers to or is otherwise based on these projected cost data and average retail rates. These confidential portions are being filed as a supplement to the Report.

Public disclosure of such cost data and average rate projections could prove very damaging to the Company in the competitive marketplace, and would place AEP at a significant disadvantage in the wholesale and retail marketplace. The projected cost data and average rate information are proprietary to AEP, and have not been publicly disclosed to any member of the public or to any other regulatory agency. In addition, public disclosure of such cost data and average rate projections to potential or current investors might expose AEP to an unnecessary and unreasonable risk of litigation should the projections later fail to meet investor expectations.

Public Service Commission Regulation 807 KAR 5:001, Section 7(2)(a)(1) requires AEP to set forth the specific grounds under the Kentucky Open Records Act (KRS 61.870, et seq.) which support an order granting confidential treatment. KRS 61.878(c)(1)(b) supports an Order of confidential treatment.

KRS 61.878(c)(1)(b) excludes from the open records act:

> "Records confidentially disclosed to an agency, generally recognized as confidential or proprietary, which if openly disclosed would present an unfair commercial advantage to competitors of the entity that disclosed the records, and which are compiled and maintained . . . in conjunction with the regulation of commercial enterprise . . ."

This section applies to the cost data and average rate information contained in the supplement to AEP's October 21st Report. First, the future cost data and average rate projections being filed with the Commission are "generally recognized as confidential or proprietary." These cost data and average rate projections are not definitive (because of the changing market conditions), but also highly confidential. Such confidentiality will be critical in any future competitive marketplace.

Second, disclosure of the confidential information would permit an unfair commercial advantage to AEP's competitors. These projections are especially sensitive, and their disclosure would be of great advantage to a competitor electric utility in the wholesale or retail power market. Such information might permit a competitor to underbid AEP based on an unfair commercial advantage; a result which would be detrimental not only to AEP but to the marketplace as well. Since AEP currently remains a regulated electric utility, the PSC should protect the public interest, in the absence of full competition, by keeping confidential AEP's projected cost data and average retail rates.

Third, and obviously, the information submitted in the supplement to AEP's IRP Report has been compiled and is being submitted "in conjunction with the regulation of a commercial enterprise." Accordingly, the supplemental filing should be accorded confidential treatment under 807 KAR 5:001, Section 7.

For the foregoing reasons, AEP requests the Kentucky Public Service Commission to afford confidential treatment to the confidential and proprietary supplement to AEP's IRP Report filed October 21, 1999 (which relates to future cost data and average rate projections). Alternatively, AEP requests a Public Service Commission hearing on this Motion at the Commission's convenience.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by first class mail, postage prepaid, upon the following parties, this 21st day of October, 1999.

Office of Attorney General
Division of Rate Intervention
P. O. Box 2000
Frankfort, KY 40602-2000

David F. Boehm
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KENTUCKY POWER COMPANY

INTEGRATED RESOURCE PLANNING REPORT
TO THE
KENTUCKY PUBLIC SERVICE COMMISSION

CONFIDENTIAL SUPPLEMENT

October 21, 1999

CONFIDENTIAL INFORMATION

Requested information that the Company considers proprietary and confidential is provided herein. A list of such information is given below.

Exhibit 1.	AEP System, Steam Generating Capacity, Assumed Fuel & O&M Cost Escalation Factors, 1999-2013
Exhibit 2.	AEP System, Key Assumptions for Assumed Future Capacity Additions
Exhibit 3.	Kentucky Power Company, Integrated Resource Plan, Financial Information

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KENTUCKY POWER COMPANY

INTEGRATED RESOURCE PLANNING REPORT
TO THE
KENTUCKY PUBLIC SERVICE COMMISSION

Submitted Pursuant to
Commission Regulation 807 KAR 5:058

October 21, 1999

KENTUCKY POWER COMPANY

INTEGRATED RESOURCE PLANNING REPORT
TO THE
KENTUCKY PUBLIC SERVICE COMMISSION

Submitted Pursuant to
Commission Regulation 807 KAR 5:058

October 21, 1999

This report was prepared under the supervision of:

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1. OVERVIEW AND SUMMARY

1. OVERVIEW AND SUMMARY

A. GENERAL REMARKS

Kentucky Power Company (KPCo), authorized to do business in Kentucky as American Electric Power (AEP), is one of seven operating companies of the multi-state AEP System, which is planned and operated on a wholly integrated basis[1]. In this regard, KPCo's resource plans must be considered in the context of the AEP System.

This report presents the results obtained from evaluations carried out in connection with the development of integrated resource plans for the AEP System and KPCo. The information contained herein includes assumptions relating to overall study parameters, as well as results obtained from option-screening analyses and the integration of supply-side resources and demand-side management (DSM) programs.

With regard to compliance with the Clean Air Act Amendments of 1990 (CAAA), AEP's compliance strategy, which utilizes scrubbing at Ohio Power Company's Gavin Plant, includes the continual evaluation of alternate fuel strategies and opportunities to purchase SO_2 allowances to lower the overall cost-impact of compliance. Also, the technologies to reduce NOx emissions either have been or will be installed at all of the AEP generating units in order to comply with the inception of the CAAA's Phase II air emission requirements in the year 2000.

Currently, and for the near term, the AEP System has adequate generation resources to meet the load requirements of the customers of its operating companies (including KPCo). In the longer term, with the additional supply-side resources and DSM programs reflected in the integrated resource plan presented in this report, the AEP System (including KPCo) is expected to have adequate resources to serve its customers' requirements throughout the forecast period.

The AEP System's ability to meet its customers' future electric needs will be affected by transmission reinforcement projects planned for the future, particularly the Wyoming-Cloverdale 765-kV line (or the alternative Wyoming-Jacksons Ferry 765-kV line), in the southeastern portion of the System's service territory. If such projects are not completed as planned, then the reliability of service to AEP customers would be jeopardized.

The planning process is a continuous activity; assumptions and plans are being continually reviewed as new information becomes available, and are modified as appropriate. Indeed, the resource expansion plan reported herein reflects, to a large extent, assumptions that are subject to change; it is simply a snapshot of the future at this time. It is not a commitment to a specific course of action, since the future, now more than ever before, is highly uncertain, particularly in light of the move to increasing competition among suppliers in the marketplace and restructuring in the industry. In this regard, there are a growing number of federal and state initiatives that

[1]The operating companies are: Appalachian Power, Roanoke, Virginia; Columbus Southern Power, Columbus, Ohio; Indiana Michigan Power, Fort Wayne, Indiana; Kentucky Power, Ashland, Kentucky; Ohio Power, Canton, Ohio; Kingsport Power, Kingsport, Tennessee; and Wheeling Power, Wheeling, West Virginia. All of the AEP operating companies do business as AEP.

address the many issues related to industry restructuring and customer choice. Along these lines, ongoing dialogues are continuing with regulators and other interested stakeholders across the AEP System to deal with such issues.

However, what is of more immediate and practical concern are the actions and commitments that will be made in the near term. In this regard, committed or anticipated capability changes on the AEP System through the year 2001 include: rerating of the Smith Mountain Pumped Storage Plant (+36 MW), a 25-MW purchase from a PURPA Qualifying Facility, and the return of 455 MW of capacity upon termination of a unit power sale to a neighboring electric utility. Beyond these changes, it is envisioned at this time that the AEP System will have adequate generation resources to meet its anticipated requirements over the next several years, and that additional resources will not be required until about the year 2005.

It should be noted that the load forecasts and resource plans that are presented herein do not reflect the possible impacts of the proposed merger between American Electric Power Company, Inc. and Central and South West Corporation. That proposed merger, which was announced in December 1997, is currently undergoing regulatory review. Also, these forecasts and plans are based on the assumption that the traditional regulatory paradigm and vertically integrated structure of the electric utility industry will continue throughout the forecast period. In view of the rapid and sweeping changes that are under way in the federal and state legislative and regulatory arenas with respect to the electric utility industry, the traditional concepts of utility forecasting, planning and operation, along with traditional ways of conducting business, will likely change in the future. The impacts of such changes are not known at this time.

B. PLANNING OBJECTIVES

The primary objective of power system planning is to assure the reliable, adequate, and economical supply of electric power and energy to the consumer, in an environmentally compatible manner. Implicit in this primary objective are related objectives, which include, in part: (1) maximizing the efficiency of operation of the power supply system, and (2) encouraging the wise and efficient use of energy. Achievement of these objectives necessarily involves consideration of supply-side options, including various types of generation resources, as well as demand-side options, involving customer load modification programs.

In the planning of power supply resources for the AEP System, consideration is given to several broad factors, including: (1) reliability, i.e., the ability of the system to provide continuous electric service not only under normal conditions, but also during various contingency conditions, (2) economy, so as to minimize the cost of resources on a long-term basis, (3) environmental compatibility, (4) financial requirements, and (5) flexibility, i.e., the extent to which plans for future resources can be adjusted to meet changing conditions.

C. COMPANY OPERATIONS AND INTERRELATIONSHIP WITH THE AEP SYSTEM

KPCo serves a population of about 386,000 (170,000 retail customers) in a 3,762 square-mile area in eastern Kentucky. The principle industries served are coal mining, petroleum refining, primary metals and chemicals. The Company also sells and transmits power at wholesale to other electric utilities, municipalities and non-utility entities engaged in the wholesale power market.

KPCo's internal load usually peaks in the winter; the all-time peak internal demand of 1,432 megawatts (MW) occurred on January 5, 1999. On July 30, 1999, an all-time summer peak internal demand of 1,215 MW was experienced. Of KPCo's total internal energy requirements in 1998, which amounted to 6,992 gigawatt-hours (GWh), residential, commercial and industrial energy sales accounted for 31%, 17% and 45%, respectively. Public street and highway lighting, sales for resale, and all other categories accounted for the remaining 7%.

In comparison, the AEP System collectively serves a population of about 6.6 million (3.0 million retail customers) in a 41,000 square-mile area in parts of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. In 1998, the residential, commercial and industrial customers accounted for 26%, 20% and 40%, respectively, of the AEP System's total internal energy requirements of 117,071 GWh. The remaining 14% was supplied for use in the public street and highway lighting, sales for resale, and all other categories. In addition, the AEP System supplied 21,735 GWh principally to non-affiliated investor-owned electric utilities.

The AEP System experienced its all-time peak internal demand of 19,952 MW in the summer season of 1999, on July 30. The System's all-time winter peak internal demand, 19,557 MW, was experienced on February 5, 1996. If sales to non-affiliated power systems are included, the AEP System reached its all-time peak total demand of 25,940 MW on June 17, 1994.

KPCo owns and operates the 1,060-megawatt, coal-fired Big Sandy Plant, consisting of an 800-MW unit and a 260-MW unit, at Louisa, Kentucky, and has a unit power agreement with AEP Generating Company, an affiliate, to purchase 390 megawatts of capacity through 1999 (or 2004, if extended) from the Rockport Plant, located in southern Indiana. In comparison, as of January 1, 1999, the AEP System's total generating capability was 23,759 MW (or 23,054 MW, after adjusting for 705 MW of unit power sales), which includes predominantly coal-fired generating units, along with conventional hydroelectric, pumped storage, and nuclear capacity.

The AEP System's major operating companies, including KPCo, are electrically interconnected by a high-capability transmission system extending from Virginia to Michigan. This transmission system, consisting of an integrated 765-kV, 500-kV, 345-kV, and 230-kV extra-high-voltage network, together with an extensive underlying 138-kV transmission network, and numerous interconnections with neighboring power systems, has been planned and constructed to provide an adequate and reliable means for integrating the AEP System's major power generating plants with its principal load centers. This single integrated power system is centrally dispatched from the AEP System Control Center located in Columbus, Ohio.

Also, KPCo is directly interconnected with the following unaffiliated entities: Kentucky Utilities Company, East Kentucky Power Cooperative, Inc. and the Federal government's Tennessee Valley Authority.

D. LOAD FORECASTS

It should be noted that the load forecasts presented herein were developed in late 1998, and do not reflect the experience for the winter season of 1998/99 and later, or other relevant changes.[2]

KPCo's forecasts of energy consumption for the major customer classes were developed by using both short-term and long-term econometric models. These energy forecasts were determined in part by forecasts of the regional economy, which, in turn, are based on the September 1998 national economic forecast of RFA (formerly Regional Financial Associates, Inc.; now a unit of Dismal Sciences, Inc.). The forecasts of seasonal peak demands were developed using an econometric model of monthly peaks.

Some of the key assumptions on which the load forecast is based include:

- moderate U.S. economic growth;
- declining real (inflation-corrected) average electricity prices through 2003; constant real prices thereafter;
- generally slow growth in the company's service-area population;
- normal weather.

Also, the forecast for the AEP System reflects the exclusion, beginning in mid-1998, of the peak demands of certain sales-for-resale customers, mainly municipals and cooperatives, who gave notices of the termination of their contracts for electric power and energy from AEP. The AEP System forecast was also adjusted to reflect the termination, at the end of 1999, of AEP's contract to provide electric power and energy to its largest customer (located in Ohio). The customer has contracted with another supplier for its power needs after 1999.

Table 1 provides a summary of the "base" forecasts of the seasonal peak internal demands and annual energy requirements for KPCo and the AEP System for the years 1999 to 2019. The forecast data shown on this table do not reflect any adjustments for expanded DSM programs. However, inherent in the forecast are the impacts of past customer conservation and load management activities, including DSM programs already in place.

As Table 1 indicates, during the period 1999-2019, KPCo's base internal energy requirements are forecasted to increase at an average annual rate of 1.7%, while the corresponding summer and

[2]The load forecasts (as well as the historical loads) presented in this report reflect the traditional concept of internal load, i.e., the load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission service by the utility. Such load serves as the starting point for the load forecasts used for generation planning. Internal load is a subset of *connected load*, which also includes directly connected load for which the utility serves only as a transmission provider. Connected load serves as the starting point for the load forecasts used for transmission planning.

winter peak internal demands are forecasted to grow at average annual rates of 1.6% and 1.8%, respectively. KPCo's annual peak demand is expected to continue to occur in the winter season.

TABLE 1
KPCo and AEP System
Forecast of Peak Internal Demand and Energy Requirements
Before Adjusting for Expanded DSM Programs
1999-2019

Year	KPCo Peak Internal Demand Summer (MW)	KPCo Peak Internal Demand Winter Following (MW)	KPCo Internal Energy Req'ts (GWh)	AEP Peak Internal Demand Summer (MW)	AEP Peak Internal Demand Winter Following (MW)	AEP Internal Energy Req'ts (GWh)
1999	1,231	1,462	7,297	19,795	19,082	118,710
2000	1,250	1,488	7,406	19,727	19,372	116,116
2001	1,270	1,512	7,524	20,060	19,660	118,205
2002	1,291	1,537	7,632	20,407	19,955	120,268
2003	1,312	1,570	7,746	20,757	20,244	122,358
2004	1,336	1,602	7,895	21,088	20,533	124,168
2005	1,361	1,635	8,045	21,419	20,821	125,978
2006	1,385	1,667	8,194	21,750	21,110	127,788
2007	1,410	1,699	8,343	22,080	21,399	129,598
2008	1,434	1,732	8,493	22,411	21,687	131,408
2009	1,459	1,764	8,642	22,742	21,976	133,219
2010	1,484	1,796	8,792	23,073	22,265	135,029
2011	1,508	1,829	8,941	23,403	22,553	136,839
2012	1,533	1,861	9,090	23,734	22,842	138,649
2013	1,557	1,894	9,240	24,065	23,131	140,459
2014	1,582	1,926	9,389	24,395	23,419	142,269
2015	1,607	1,958	9,538	24,726	23,708	144,079
2016	1,631	1,991	9,688	25,057	23,997	145,889
2017	1,656	2,023	9,837	25,388	24,285	147,700
2018	1,680	2,056	9,987	25,718	24,574	149,510
2019	1,705	2,090	10,136	26,049	24,873	151,320
% Average Growth Rate, 1999-2019	1.6	1.8	1.7	1.4	1.3	1.2

Note: AEP Peak Internal Demands indicated above include "traditional" interruptible/non-firm loads, which are assumed to aggregate to 674 MW (summer) and 681 MW (winter) throughout the forecast period. KPCo does not have such loads.

Similarly, the AEP System's base internal energy requirements during the forecast period are projected to increase at an average annual rate of 1.2%, while the corresponding summer and winter peak internal demands are projected to grow at average annual rates of 1.4 and 1.3%, respectively. The AEP System's annual peak demand is expected to occur in the summer season.

Table 2 shows KPCo and AEP load forecast information as in Table 1, except that the peak demands and energy requirements have been reduced to reflect the impact of the expanded company-sponsored DSM programs assumed to be implemented during the forecast period. A comparison of the data shown on Tables 1 and 2 indicates that the expanded DSM programs do not affect the long-term load growth rates.

TABLE 2
KPCo and AEP System
Forecast of Peak Internal Demand and Energy Requirements
After Adjusting for Expanded DSM Programs
1999-2019

Year	KPCo			AEP		
	Peak Internal Demand		Internal Energy Req'ts (GWh)	Peak Internal Demand		Internal Energy Req'ts (GWh)
	Summer (MW)	Winter Following (MW)		Summer (MW)	Winter Following (MW)	
1999	1,231	1,460	7,295	19,793	19,071	118,704
2000	1,249	1,486	7,402	19,722	19,351	116,098
2001	1,269	1,509	7,520	20,052	19,630	118,177
2002	1,290	1,533	7,627	20,396	19,915	120,228
2003	1,311	1,566	7,740	20,743	20,194	122,308
2004	1,335	1,597	7,888	21,071	20,472	124,106
2005	1,359	1,630	8,038	21,401	20,760	125,909
2006	1,383	1,662	8,187	21,732	21,049	127,719
2007	1,408	1,694	8,336	22,062	21,338	129,529
2008	1,432	1,727	8,486	22,393	21,627	131,339
2009	1,457	1,759	8,635	22,724	21,916	133,150
2010	1,482	1,791	8,785	23,055	22,205	134,961
2011	1,506	1,824	8,934	23,385	22,493	136,771
2012	1,531	1,856	9,083	23,716	22,782	138,581
2013	1,555	1,889	9,233	24,047	23,071	140,393
2014	1,581	1,923	9,382	24,379	23,370	142,204
2015	1,606	1,955	9,533	24,713	23,668	144,026
2016	1,630	1,989	9,684	25,047	23,967	145,846
2017	1,655	2,021	9,834	25,380	24,255	147,668
2018	1,679	2,054	9,984	25,710	24,544	149,478
2019	1,704	2,088	10,133	26,041	24,843	151,288
% Average Growth Rate, 1999-2019	1.6	1.8	1.7	1.4	1.3	1.2

Note: AEP Peak Internal Demands indicated above include "traditional" interruptible/non-firm loads, which are assumed to aggregate to 674 MW (summer) and 681 MW (winter) throughout the forecast period. KPCo does not have such loads.

E. DSM PROGRAMS AND IMPACTS

Over the years, AEP routinely performed extensive analyses on a wide range of DSM measures. The measures that passed the screening process were grouped into programs for potential implementation. Those programs were, in turn, evaluated to determine their appropriateness for individual jurisdictions within the AEP System. This process has undergone several revisions and the portfolio of DSM programs has been modified as appropriate.

The estimated future impacts of AEP's DSM programs have been reduced in the past few years, but their overall effects are still material, considering the pertinent developments in this area. In the first place, increased federally mandated energy efficiency standards and years of customer educational programs are making energy efficiency a normal practice. Consequently, much of the efficiency effects associated with DSM programs have been captured, or are embedded, in the base load forecast. Secondly, in anticipation of deregulation, the emphasis of the DSM evaluation process has been shifted from a societal perspective, as reflected in the Total Resource Cost (TRC) test, to the ratepayer perspective, as reflected in the Ratepayer Impact Measure (RIM) test. Thirdly, the uncertainties regarding (a) customer choice of energy supplier in the future and (b) DSM cost-recovery mechanisms in the AEP System's different state jurisdictions serve to hinder the effectiveness and meaningfulness of the DSM evaluation process.

TABLE 3
AEP System and KPCo
Expanded DSM Programs

AEP System	KPCo
Residential Programs:	
1. Targeted Energy Efficiency (Low-Income Weatherization)	X
2. Energy Fitness	X (a)
3. High-Efficiency Heat Pump (Single/Two-Family Home)	X
4. High-Efficiency Heat Pump Mobile Home	X
5. Load Management Water Heating	X
6. Mobile Home New Construction	X
Commercial Programs:	
SMART Audit/Incentive	X
Industrial Programs:	
SMART Audit/Incentive	- (b)

Note: (a) For KPCo, the Residential Energy Fitness Program was discontinued in May 1999, with Collaborative approval.

(b) For KPCo, the Industrial SMART Audit/Financing Program was discontinued at year-end 1998, with Collaborative approval.

Table 3 lists the DSM programs that passed screening in one or more state jurisdictions of the AEP System. This table also indicates those DSM programs that were proposed by the KPCo DSM Collaborative (except for the Load Management Water Heating Program) and approved by the Commission.

Table 4 provides a summary of the estimated load impacts of implementing the expanded DSM programs for KPCo the AEP System for the years 1999 to 2019, based on the market penetration rates assumed. It was also assumed that there will be no new DSM program participants after the year 2004. Thus, for KPCo, the expanded DSM programs would reduce the base forecast of peak internal demand for the winter season of 2009/10 by an estimated 5 MW (0.3%). In comparison, the summer 2009 peak demand would be reduced by 2 MW. KPCo's corresponding base forecast of internal energy requirements for the year 2009 would be reduced by an estimated 7 GWh.

Similarly, for the overall AEP System, the winter 2009/10 peak demand would be reduced by 60 MW (0.3%) and the summer 2009 peak demand would be reduced by 18 MW. The corresponding incremental DSM impact with respect to AEP's forecasted energy requirements for 2009 would be 69 GWh (0.1%).

As Table 4 indicates, the DSM impacts generally increase in time through about the year 2005, and remain relatively stable until about 2014, decreasing gradually thereafter. Thus, for the AEP System, the expanded DSM impact on winter-season peak demand would be reduced from a level of 60 MW in winter 2009/10 to a level of 30 MW in winter 2019/20. These estimated impacts reflect the assumption that new DSM program participants will continue to be added through 2004, after which there will be no new participants.

TABLE 4
KPCo and AEP System
Estimated Load Impacts of Expanded DSM Programs
1999-2019

	KPCo			AEP		
	Demand Reduction			Demand Reduction		
Year	Summer (MW)	Winter Following (MW)	Energy Reduction (GWh)	Summer (MW)	Winter Following (MW)	Energy Reduction (GWh)
1999	0	2	2	2	11	6
2000	1	2	4	5	21	18
2001	1	3	4	8	30	28
2002	1	4	5	11	40	40
2003	1	4	6	14	50	50
2004	1	5	7	17	61	62
2005	2	5	7	18	61	69
2006	2	5	7	18	61	69
2007	2	5	7	18	61	69
2008	2	5	7	18	60	69
2009	2	5	7	18	60	69
2010	2	5	7	18	60	68
2011	2	5	7	18	60	68
2012	2	5	7	18	60	68
2013	2	5	7	18	60	66
2014	1	3	7	16	49	65
2015	1	3	5	13	40	53
2016	1	2	4	10	30	43
2017	1	2	3	8	30	32
2018	1	2	3	8	30	32
2019	1	2	3	8	30	32

Note: Expanded DSM program impacts result from installations assumed to be made in the future and are not reflected in the base-load forecast. Impacts of DSM program installations already in-place, i.e., embedded DSM program impacts, are reflected in the base-load forecast.
As of the end of 1998, the estimated aggregate embedded DSM program impacts were as follows:

	Summer MW	Winter MW	Annual Gwh
KPCo	4	16	37
AEP	70	170	326

Since DSM program persistence is less than 100%, these embedded DSM impacts are expected to diminish gradually over the forecast period.

The expanded DSM program impacts shown in Table 4 are in addition to the impacts of DSM program installations already in place, i.e., the DSM measures implemented prior to 1999. Such in-place (or "embedded") DSM impacts are already reflected in the base-load forecast. Estimates of these embedded DSM program impacts as of the end of 1998 are shown in the bottom portion of Table 4.

The impacts shown in Table 4 reflect the effects of DSM implementation experience gained thus far, but do not take into account the latest results of the DSM program evaluations filed with the Commission on August 16, 1999.

F. SUPPLY-SIDE RESOURCE EXPANSION

AEP should have enough installed generation to reliably serve its anticipated peak demand and energy requirements through about the year 2004. For the years beyond 2004, assuming that the loads materialize as projected, it appears that new generation resources will be needed.

In the evaluation of future resource additions for the AEP System, consideration is normally given to several alternative generation technologies, including gas-fired generation, i.e., simple-cycle combustion turbines and combined cycle units, to supplement the System's base-load coal-fired and nuclear generation. However, at the present time, apart from the capability changes committed or anticipated through the year 2001, as noted on Table 5, there are no specific plans for new generation resource additions on the AEP System. Size, technology type, ownership (among AEP operating companies) or means of acquisition, and precise timing of subsequent future generation resource additions on the AEP System have not yet been determined. When the time for commitment to specific generation resource additions approaches, all means for adding such resources, including self-build and external resource options, will be considered.

For the purposes of this report, in view of the strong likelihood of restructuring of the electric industry during the forecast period, and of the many uncertainties associated with the future of the industry and the matter of customer choice, instead of speculating as to the specifics of possible future generation resource additions, a generation expansion has been developed in terms of "blocks" of currently undesignated new generation resources that would be added in the forecast period.

As shown in Table 5, starting in the year 2005, the AEP System could add 9,100 MW of new generating capacity resources through the year 2019 to maintain a reserve margin of about 12% of the total firm load obligation, the target margin used in the study. This amount of new generation resources takes into account the assumed retirement, for study purposes only, of certain generating units that will have reached 50, 60 or 70 years of service life during this period.

Also, for the purposes of this report, the allocation of new generation resources among the AEP operating companies was determined based on the relative reserve margins of those companies. To accomplish this, each successive generation resource addition was generally assigned to the operating company, or a combination of operating companies, with the lowest reserve. From that analysis, KPCo's portion of the AEP System's generation resource additions included in the expansion would amount to 1,100 MW, as shown in Table 5. However, this should not be construed to reflect any sort of commitment at this time. If new generation resources are indeed to be added by AEP, the determination of actual ownership of, or responsibility for, individual resource additions will take additional factors into account, and will depend on the circumstances at the time such decisions are made.

TABLE 5
AEP System and KPCo
New Generation Resource Additions
1999-2019

Year	AEP System		KPCo	
	MW	Cumulative MW	MW	Cumulative MW
1999-2004	-	-	-	-
2005	500	500	300	300
2006	400	900	100	400
2007	400	1,300	100	500
2008	-	1,300	-	500
2009	1,800	3,100	200	700
2010	100	3,200	-	700
2011	700	3,900	100	800
2012	400	4,300	-	800
2013	800	5,100	-	800
2014	700	5,800	100	900
2015	1,500	7,300	100	1,000
2016	400	7,700	-	1,000
2017	400	8,100	-	1,000
2018	600	8,700	100	1,100
2019	400	9,100	-	1,100

Note: All of the above generation resource additions are uncommitted.
Committed/anticipated capability changes during the forecast period are as follows:
Jan. 2000: Rerate of Smith Mountain Pumped Storage Plant (+36 MW).
Jan. 2000: Return of 455 MW of Rockport Unit 1 capacity upon termination of Unit Power sale to VEPCo.
Jan. 2001: Start of 25/17-MW (winter/summer) QF purchase by APCo (Summersville Hydro).
Jan. 2005: Return (to I&M from KPCo) of 390 MW of Rockport Units 1 & 2 capacity upon termination of Unit Power sale to KPCo. (AEP intra-system transaction; total AEP capacity is not affected.)
Jan. 2010: Return of 250 MW of Rockport Unit 2 capacity upon termination of Unit Power sale to CP&L.
Sep. 2012: Exclusion of Buckeye Power Cardinal capacity (Units 2&3) from System capability upon termination of BP Contract (1,230/1,215 MW, winter/summer)
Assumed generating-unit retirements:

Jan. 2009:	Muskingum River 1-4	(840 MW)	Jan. 2015:	Tanners Creek 1-4	(995 MW)
	Kammer 1-3	(630 MW)		Glen Lyn 5	(95 MW)
Jan. 2011:	Sporn 1-4	(600 MW)	Jan. 2016:	Picway 5	(100 MW)
Jan. 2013:	Conesville 1-3	(415 MW)	Jan. 2018:	Glen Lyn 6	(240 MW)
Jan. 2014:	Kanawha River 1-2	(400 MW)			

Table 6 shows the resulting projections of summer peak demands (both including and excluding interruptible/non-firm loads), capabilities, and associated reserve margins for the AEP System for the period 2000-2019. For the purposes of this table, the peak demands have been adjusted to: (1) reflect the expanded DSM impacts and (2) include total Buckeye Power load (which, for planning purposes, is treated as part of AEP System control-area load) and committed firm sales to neighboring power systems. Also, the capability figures, which reflect the changes shown on Table 5, have been adjusted to: (1) include the total capability of Buckeye Power's generating units and (2) exclude the capability associated with unit power sales. As Table 6 indicates, the addition of new generation resources starting in 2005 enables the projected reserve margins, after accounting for potential interruptible load curtailments, to be maintained at about 12% of the total firm load obligation.

TABLE 6 AEP System (Including Buckeye Power) Projected Summer Peak Demands, Generating Capabilities, and Margins 2000-2019							
	Peak Demand MW			Margin Based on Including Interruptible Load		Margin Based on Excluding Interruptible Load	
Year	Including Interruptible load	Excluding Interruptible load	Capability MW	MW	Percent of Demand	MW	Percent of Demand
2000	21,100	20,426	24,454	3,354	15.9	4,028	19.7
2001	21,465	20,791	24,471	3,006	14.0	3,680	17.7
2002	21,839	21,165	24,471	2,632	12.1	3,306	15.6
2003	22,217	21,543	24,471	2,254	10.1	2,928	13.6
2004	22,574	21,900	24,471	1,897	8.4	2,571	11.7
2005	22,937	22,263	24,971	2,034	8.9	2,708	12.2
2006	23,297	22,623	25,371	2,074	8.9	2,748	12.1
2007	23,659	22,985	25,771	2,112	8.9	2,786	12.1
2008	23,665	22,991	25,771	2,106	8.9	2,780	12.1
2009	23,996	23,322	26,181	2,185	9.1	2,859	12.3
2010	24,327	23,653	26,531	2,204	9.1	2,878	12.2
2011	24,452	23,778	26,651	2,199	9.0	2,873	12.1
2012	24,783	24,109	27,051	2,268	9.2	2,942	12.2
2013	24,047	23,373	26,241	2,194	9.1	2,868	12.3
2014	24,379	23,705	26,551	2,172	8.9	2,846	12.0
2015	24,713	24,039	26,981	2,268	9.2	2,942	12.2
2016	25,047	24,373	27,291	2,244	9.0	2,918	12.0
2017	25,380	24,706	27,691	2,311	9.1	2,985	12.1
2018	25,710	25,036	28,056	2,346	9.1	3,020	12.1
2019	26,041	25,367	28,456	2,415	9.3	3,089	12.2

Inasmuch as there are many assumptions, each with its own degree of uncertainty, which had to be made in carrying out the resource evaluations, changes in these assumptions could result in significant modifications in the resource plan reflected in Tables 5 and 6, depending upon the parameters being changed. In this respect, sensitivity analyses indicated that the resource plan is sufficiently flexible to accommodate possible changes in key parameters, including load growth. As such changes are recognized, updated and more refined input information must be continually evaluated, and resource plans modified as appropriate.

G. PLAN IMPLEMENTATION

As previously noted, the planning process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available, and are modified as appropriate. In this regard, the Company's resource implementation plan, i.e., its short-term action plan, includes continuing the monitoring and evaluation of existing and potential supply-side resources and DSM programs. However, in light of the uncertainties of the future, short-term plans, as well as long-term plans, are likely to change as the future unfolds.

With respect to supply-side plans, apart from the capability changes already committed or anticipated during the next five years, it is not expected that the AEP System will require additional generation resources until about 2005. The initial generation resource additions are assumed to be available on a short-lead-time basis. Thus, there is no immediate need to make firm commitments for such resources. In any event, with the restructuring that is expected to take place in the industry, the need for such commitments is highly uncertain.

With respect to DSM program activities, the Company is continuing its active involvement in the KPCo DSM Collaborative, whose members represent residential, commercial and industrial customers. The Collaborative, which was established in November 1994 to develop DSM plans, including program designs, budgets, and cost recovery mechanisms, is responsible for overseeing the implementation, monitoring and evaluation of existing DSM programs and consideration of new DSM programs. In this regard, the Collaborative has continued to review the DSM programs and modify them as appropriate.

The initial DSM plan, covering the three-year period 1996-1998, was filed by the Collaborative on September 27, 1995, and approved by the Commission in an Order dated December 4, 1995 (Case No. 95-427). In approving the plan, the Commission also approved the recovery of all program costs, lost revenues, and incentives for KPCo through a surcharge mechanism. The Commission also ordered that KPCo file every six months a report that describes the operation and progress of the DSM plan and that includes any studies related to the plan.

On August 14, 1998, the Collaborative filed a request for Commission approval of a one-year extension (through 1999) for the DSM plan, as updated. Approval of the request was granted on October 27, 1998. Later, in a DSM Collaborative Report filed on August 16, 1999, the Collaborative requested approval of a three-year extension (2000-2002) for the current DSM plan. Also, as was the case with the first such report filed two years earlier (on August 15, 1997), this second DSM Collaborative Report included a collection of comprehensive evaluation reports on the DSM programs that have already been implemented.

Also, pursuant to the Commission's December 1995 Order, the Collaborative has been providing DSM Status Reports to the Commission every six months. The first set of these reports was filed on August 15, 1996, and the most recent (the seventh) set was filed on August 16, 1999, as part of the DSM Collaborative Report noted above. This most recent set of DSM Status Reports includes, for the various DSM programs that the Company currently has under way, updated information on program participation levels, program costs and estimated load impacts through June 30, 1999.

In view of the potential for temporary, or short-term, emergency operating conditions on the AEP System (as would result from a generating capacity deficiency), and to provide additional options for customers, KPCo and other AEP operating companies recently introduced Tariff Riders for Emergency Curtailable Service (ECS) and Price Curtailable Service (PCS). These new offerings provide for voluntary curtailments by commercial and industrial customers who normally take firm service, with demands greater than 3 MW. In the event of curtailments, such customers would be compensated (i.e., credited) by the Company, based on the amount of energy curtailed and the respective pricing provisions of these riders.

The ECS Tariff Rider is offered as a means of minimizing the potential for emergency operating conditions in order to maintain service to the Company's other firm service customers, by curtailment of load served under this rider. This offering permits the Company to implement an additional step, i.e., ECS curtailments, in the existing AEP System Emergency Operating Plan. The rider provides that the customer will not be subject to more than 50 hours of curtailment during either the summer or winter season. The rider also provides for two price options, which are dependent on the maximum number of hours the customer is willing to be curtailed per event.

The PCS Tariff Rider is offered to provide customers an option to manage their total price of electricity by curtailing firm load on an economic basis. This offering allows the customer to specify a maximum number of days in each of the four seasons of the year they are willing to curtail, and they may choose from three options as to the maximum number of hours per curtailment. The customer also specifies the minimum price for which they are willing to curtail.

The amount of load that will be served in the future under the ECS and PCS Tariff Riders will, of course, depend on the extent to which eligible customers elect to participate.

2. LOAD FORECAST

A. SUMMARY OF LOAD FORECAST

A.1. Forecast Assumptions

The load forecasts for KPCo and the other operating companies in the AEP System are based on a forecast of U.S. economic growth provided by RFA (formerly Regional Financial Associates, Inc.; now a unit of Dismal Sciences, Inc.). The load forecasts presented herein are based on an RFA economic forecast issued in September 1998 and on AEP load experience prior to 1999. RFA projects moderate growth in the U.S. economy during the 1999-2019 forecast period, characterized by a 2.4% annual rise in real Gross Domestic Product (GDP), and moderate inflation as well, with the consumer price index expected to rise by 2.8% per year. Industrial output, as measured by the Federal Reserve Board's (FRB's) index of industrial production, is expected to grow at 2.7% per year during the same period. For the regional economic outlook, the 1998 forecast developed by Woods & Poole Economics, Inc. was utilized. The outlook for KPCo's service area projects employment growth of 1.0% per year during the forecast period and real regional income per-capita growth of 1.2%.

Inherent in the load forecasts are the impacts of past customer energy conservation and load management activities, including company-sponsored demand-side management (DSM) programs already implemented. The load impacts of future, or expanded, DSM programs are analyzed and projected separately, and appropriate adjustments applied to the load forecasts.

A.2. Forecast Highlights

KPCo's total internal energy requirements, before consideration of the effects of expanded DSM programs, are forecasted to increase at an average annual rate of 1.7% from 1999 to 2019. The corresponding summer and winter peak internal demands are forecasted to grow at average annual rates of 1.6% and 1.8%, respectively. KPCo's annual peak demand is expected to continue to occur in the winter season.

The AEP System's internal energy requirements during the forecast period are projected to increase at an average annual rate of 1.2%, before consideration of the effects of expanded DSM. Summer and winter peak internal demands are expected to grow at average annual rates of 1.4% and 1.3%, respectively. Historically, the AEP System has generally peaked in the winter season; however, the peak demand forecast projects a summer-season peak throughout the forecast period, with winter peaks following closely behind.

The load effects of expanded DSM generally increase in time through about the year 2005 and remain relatively stable until about 2014, diminishing thereafter. Over the 20-year forecast period, the projected expanded DSM has little effect on load growth. For both the AEP System and KPCo, the expected annual rate of growth in internal energy requirements, as well as in the summer and winter peak internal demands, after accounting for expanded DSM, is unchanged from the growth rate without DSM.

B. OVERVIEW OF FORECAST METHODOLOGY

The Company's load forecasts are based mostly on econometric analyses of time-series data. This method has much to recommend it for load forecasting. One advantage is that it provides a relatively efficient means of producing an internally consistent forecast. This consistency is enforced by the necessity that the model logic be specified in mathematical terms and that all forecast assumptions be defined in quantifiable terms. Another advantage is that it is readily amenable to the consideration of alternate futures through the use of scenario analysis or the development of confidence bands. A third advantage of econometric analysis is that it lends itself to objective verification of models through the application of standard statistical criteria. This aspect is particularly useful in that it facilitates comparisons of forecasting models across companies and across successive forecasts.

In practice, econometric analysis as a general method covers a wide range of specific techniques, and thus raises the issue of choice among alternatives in building and estimating forecasting models. Many of these choices are not obvious and can only be resolved through professional judgment. A similar role for professional judgment also exists in the interpretation of the statistical criteria used to judge the performance of the econometric models, which are, likewise, not always clear-cut. In the development of the Company's load forecast, such judgment is informed by a guiding principle, which is to produce as useful and as accurate a forecast as possible, within the constraints imposed by corporate resources and by the availability of data.

In pursuit of that principle, the Company's energy requirements forecast is derived from two sets of econometric models, i.e., a set of monthly short-term models and a set of annual long-term models. This procedure permits easier adaptation of the forecast to the various short- and long-term planning purposes that it serves. For the first five forecast years (through 2003), the forecast values are governed exclusively by the short-term models. For the last forecast year (2019), the forecast values are governed by the long-term models. For the transition period (2004-2018), the forecast values are interpolated linearly between monthly values of the last short-term forecast year (2003) and the last forecast year (2019). Prior to this interpolation, the annual long-term model results must be converted to monthly results. A monthly profile derived from the short-term models is used for that purpose.

In both sets of models, the major energy classes are analyzed separately. Inputs such as regional and national economic and demographic conditions, energy prices, weather factors, special information (for example, the known plans of specific major customers) and informed judgment are all utilized in producing the forecasts. The major difference between the two sets of models is that the short-term models utilize mostly trend, seasonal and weather variables, while the long-term models utilize "structural" variables, such as per-capita income, employment, energy prices and weather factors, as well as trend variables. Supporting forecasting models are used to predict the future levels of some of the inputs to the long-term energy models. For example, natural gas and coal models are used to predict sectoral natural gas prices and regional coal production. These forecasts then serve as inputs to the respective long-term energy forecasts.

Either directly, through national economic inputs to the forecast models, or indirectly, through inputs from supporting models, the Company's load forecasts are influenced greatly by the outlook for the national economy. For the load forecasts reported herein, RFA's September 1998 forecast was used as the basis for that outlook. Woods & Poole Economics' 1998 forecast was used for the regional economic forecast of income, employment and population.

The energy forecast for the total AEP System, by customer class, is obtained by summing the forecasts, by customer class, of each of the AEP operating companies.

The forecast of peak internal demand for the Company is produced by using an econometric model that relates monthly peak to monthly weather-normal energy requirements, the average daily temperature on the day of the monthly peak, and a set of monthly and seasonal binary variables. The use of forecasted energy requirements in the peak demand models ensures consistency between the Company's peak demand and energy requirements forecasts.

The forecast of peak internal demand for the AEP System is determined by summing the operating company forecasts and adjusting for diversity.

Flow charts depicting the structure of the models used in projecting KPCo's electric load requirements are shown in Exhibits 2-1 and 2-2. Page 1 of Exhibit 2-1 depicts the stages in the development of the Company's short-term and long-term internal energy requirements forecasts. Page 2 of Exhibit 2-1 identifies in greater detail the variables included in the short-term and long-term energy requirements forecasting models. Exhibit 2-2 presents a schematic of the peak internal demand forecasting model. Displays of model equations, including the results of various statistical tests, along with data sets, are provided in the Appendix.

C. FORECAST METHODOLOGY FOR INTERNAL ENERGY REQUIREMENTS

C.1. General

This section provides a detailed description of the short-term and long-term models employed in producing the forecasts of energy consumption, by customer class, for KPCo. For the purposes of the Company's load forecast, the short term is defined as the first five years of the forecast period, and the long term as beyond the tenth forecast year.

Conceptually, the difference between the short term and the long term, as it concerns electric energy consumption, has to do with the changes in the stock of electricity-using equipment, rather than with the passage of time. The short term covers the time period during which changes in this stock are minimal, and the long term as the time period during which changes in this stock can be significant. In practice, changes in equipment stocks are related to the passage of time.

In the short term, electric energy consumption is considered to be a function of the utilization of an essentially fixed stock of equipment. For residential and commercial customers, the most significant factor influencing utilization in the short term is weather. For industrial customers, economic forces that determine inventory levels and factory orders also influence short-term utilization rates. The short-term forecasting models recognize these relationships and use weather and the recent trend in load growth, along with an FRB production index for the industrial energy sector, as the primary explanatory variables in forecasting monthly energy sales one-to-five years ahead.

Over time, demographic and economic factors, such as population, employment and income, as well as technology, determine the nature of the stock of electricity-using equipment, in both its size and composition. The long-term forecasting models recognize the importance of these variables and include most of them in the formulation of the long-term energy forecasts.

Relative energy prices also have an impact on electricity consumption. One important difference between the short-term and long-term forecasting models is their treatment of energy prices. Energy prices are not included in the short-term models, but are included in the long-term models. This treatment is justified by consideration of the nature of technological and behavioral constraints on consumer response to price changes. In the short term, these constraints are severe. The presence of durable equipment stocks and the formation of price expectations based in part on past prices mitigates the short-term effect of price changes. In the long term, however, these constraints are lessened as durable equipment is replaced and as price expectations come to fully reflect price changes.

C.2. Short-term Forecasting Models

The goal of KPCo's short-term forecasting models is to produce an accurate load forecast for five years into the future. To that end, the short-term forecasting models generally employ a combination of monthly and seasonal binaries, time trends, and up to three powers of monthly heating degree-days, and two powers of monthly cooling degree-days in their formulation. The heating and cooling degree-days are measured at weather stations in the Company's service area. The purpose of using powers of heating and cooling degree-days is to capture nonlinearities in the response of load to weather. The heating and cooling degree-day terms ultimately used in each equation are tested to ensure that they produce, in combination, a reasonable weather-response curve.

One assumption made in the case of the short-term forecasting models is that the error terms are autocorrelated, i.e., that they are not independent through time. The technique that is used to estimate the models takes this into account. Many economic time-series data exhibit autocorrelated errors for reasons such as the prolonged influence over several periods of a disturbance in one period, or simple inertia in the process generating the time series. As a practical matter, short-term forecasting accuracy can often be improved by estimating an autoregressive model, which corrects for first-degree autocorrelation.

The estimation period for the short-term models was January 1988 through August 1998.

C.2.a. Residential and Commercial Energy Sales

Aggregate energy sales to residential customers and aggregate energy sales to commercial customers are forecasted using similar models. These models include monthly binary variables to capture the effect of month-to-month variations in load due to non-weather causes, and three powers of heating degree-days and two powers of cooling degree-days to capture the effects of weather. A time trend is also used as a proxy for those determinants of load that change continuously over time. Other binaries are used in some of the equations to account for discrete changes in load.

C.2.b. Industrial Energy Sales

C.2.b.1. Manufacturing

The short-term manufacturing energy sales model for KPCo includes monthly binaries, a time trend, FRB industrial production index for basic steel, and weather variables.

C.2.b.2. Mine Power

The short-term mine power energy sales forecast for KPCo is produced by models that include monthly binaries, time-trend variables, weather variables and other binary variables representing events such as the opening or closing of individual mines.

C.2.c. All Other Energy Sales

The All Other Energy Sales category for KPCo includes public street and highway lighting and sales to municipals. KPCo's municipal customers include the cities of Vanceburg and Olive Hill.

KPCo's short-term forecasting model for public street and highway lighting energy sales includes monthly binaries and a time trend. The sales-for-resale model includes monthly binaries, a time trend and weather variables.

C.2.d. Losses and Unaccounted-For Energy

In principle, losses and unaccounted-for energy (i.e., "losses") is related to total energy, but in practice it is often subject to significant discontinuities whose origin is often not well-understood. Thus, the model specifications for this category for KPCo include numerous binary variables.

C.3. Long-term Forecasting Models

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

Unlike the short-term forecasting models, which are estimated using a technique that corrects for first-degree autocorrelation, the long-term models are estimated using ordinary least-squares. It is assumed in these cases that apparent autocorrelation is more likely a symptom of specification problems stemming from causes such as errors in data or omitted variables, than of true autocorrelation. In such a case, the use of a special estimating technique, like that used in the short-term models, provides no relief. Moreover, these specification problems, while not desirable, are largely unavoidable within the limitations of the available data and are not considered sufficiently serious to bias the forecast results.

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

There are several techniques, including the use of lagged price or a moving average of price, that can be used to introduce the concept of lagged response to price change into an econometric model. Each of these techniques incorporates price information from previous periods to estimate demand in the current period.

The estimation period for the long-term load forecasting models was 1975-1997. The energy forecasts actually used only one year generated by the long-term forecasting models, i.e., 2019. Forecast values for the years between 2003 and 2019 were determined by linear interpolation between the short-term model results for 2003 and the long-term results for 2019.

C.3.a. Supporting Models

In order to produce forecasts of certain independent variables used in the internal energy requirements forecasting models, several supporting models are used, including a natural gas price model and a regional coal production model for the KPCo service area. These models are discussed below.

C.3.a.1. Natural Gas Price Model

The forecast price of natural gas used in the Company's energy models comes from a model of the U.S. natural gas industry developed in-house. This model incorporates factors affecting the supply, demand and price of natural gas for four primary consuming sectors: residential, commercial, industrial and electric utilities. The U.S. natural gas price forecast produced by this model was used to project natural gas prices, by consuming sector, for each of the states served by the AEP System, including Kentucky. Forecasts of U.S. economic variables which are exogenous to the natural gas price model were obtained from the RFA September 1998 forecast. The estimation interval for the natural gas price model, which is an annual model, was 1973-1997.

C.3.a.2. Regional Coal Production Model

A regional coal production forecast is used as an input in the mine power energy sales model. In the coal model, regional production depends mainly on the level of demand for U.S. coal for consumption by electric utilities and U.S. coal production, as well as on binary variables that reflect the impacts of special occurrences, such as strikes. In the development of the regional coal production forecast, projections of U.S. coal production were obtained from U.S. DOE/EIA's "1998 Annual Energy Outlook." The estimation period for the model was 1975-1997.

C.3.b. Residential Energy Sales

Residential energy sales for KPCo are forecasted using two models, the first of which projects the number of residential customers, and the second of which projects kWh usage per customer. The residential energy sales forecast is calculated as the product of the corresponding customer and usage forecasts.

C.3.b.1. Residential Customer Forecasts

The residential customer forecasting model is linear. The level of residential customers is related to total employment in the Company's service area. The customer model also employs a lagged dependent variable to represent the gradual adjustment of the number of residential customers to changes in total employment.

C.3.b.2. Residential Energy Usage Per Customer

The kWh usage models are linear, with the independent variables in logarithmic form. Usage is related to service-area total employment, heating and cooling degree-days, the real price of electricity and the real price of natural gas. Both of the energy price terms are 5-year moving averages to reflect the delayed effect of prices over time.

Exhibit 2-3 provides a summary of the historical and forecast values of variables used in the development of the Company's residential energy sales forecasts.

C.3.c. Commercial Energy Sales

A single model is used to forecast commercial energy sales. This model is specified as linear, with the dependent and independent variables in logarithmic form. In general, regional economic activity, weather and relative energy prices are considered to be the primary determinants of long-term commercial load growth. Regional economic activity is represented by regional commercial employment. Energy prices, represented by the Company's average price of electricity to its commercial customers, and by the statewide real price of natural gas to commercial customers, are included in the model. Weather effects are captured through the use of the number of cooling-degree days at the Huntington, West Virginia weather station. The model also employs binary variables to account for special occurrences.

Exhibit 2-3 provides a summary of the historical and forecast values of variables used in the development of the Company's commercial energy sales forecasts.

C.3.d. Industrial Energy Sales

C.3.d.1. Manufacturing

The manufacturing forecasting model relates energy sales to real price of natural gas, real price of electricity, FRB production index for manufacturing, service-area manufacturing employment and binary variables. The prices are modeled using five-year moving averages. The dependent and independent variables are modeled as linear, with the production index in logarithmic form.

Exhibit 2-4 provides a summary of the historical and forecast values of variables used in the development of the Company's manufacturing energy sales forecasts.

C.3.d.2. Mine Power

The forecast of KPCo's mine power energy consumption for non-associated mining companies is produced with a model relating mine power energy sales to regional coal production, regional coal mining employment, and average electric price to mine power customers. This model is specified as linear, with the independent variables in logarithmic form.

Exhibit 2-4 provides a summary of the historical and forecast values of variables used in the development of the mine power energy sales forecast.

C.3.e. All Other Energy Sales

The separate groups in this load category are modeled primarily with the use of time-trend variables and binary variables. Time trends are used to reflect the gradual change in load over time. In the case of street and highway lighting, the source of this change may be technological (e.g., new lighting technologies may have altered the level of energy use). In the case of municipal load, the true causes of this change are assumed to be demographic and economic trends, which affect the individual customer, but for which time-series data are not available. Binary variables are necessary to account for discrete changes in energy sales that result from events such as the addition of new customers or the renegotiation of contracts that increase or decrease energy sales to existing customers.

KPCo's municipal customers are treated as a single entity in the modeling and forecasting process. As noted in section C.2.c above, KPCo serves two separate municipal customers.

C.3.f. Losses and Unaccounted-For Energy

Losses and unaccounted-for energy is modeled as a function of the Company's total internal energy sales and its estimated share of AEP System sales to non-affiliated companies. Binaries and a time-trend variable are also used in the model.

D. FORECAST METHODOLOGY FOR SEASONAL PEAK INTERNAL DEMAND

Peak internal demands for KPCo are forecasted using a regression model that relates monthly peak to monthly weather-normal energy, the average daily temperature on the day of the monthly peak, and a set of monthly and seasonal binary variables. The model is parameterized to allow for different effects of monthly weather-normal energy in different seasons. For this purpose, a "season" is defined as one of six two-month spans, the first of which is January-February and the last of which is November-December. The estimation interval extends from January 1984 through August 1998, and the method of estimation is ordinary least-squares.

The effects of weather are specified as a piecewise linear response curve with four segments and with nodes (points at which the curve may have an elbow) at temperatures of 32 degrees, 62 degrees, and 72 degrees Fahrenheit. The effect of weather is assumed to be zero at an average daily temperature of 62 degrees. The slope of each segment of the weather response curve is allowed to vary continuously with a time trend, while maintaining continuity. The estimation yields a roughly U-shaped weather-response curve, with a minimum at 62 degrees, that tends to steepen with time (weather-sensitive load tends to increase with time, particularly in the summer months).

Whenever historical monthly peaks reflect curtailed interruptible load, the peaks are adjusted before the regression model is estimated to include the curtailed amounts. Thus, the model applies to total uncurtailed peak, and the forecast implicitly includes certain quantities that may be available for interruption.

The forecast of monthly peak demands is calculated using estimated monthly energy requirements. For all months except January and August, the average daily temperature on the day of the monthly peak is assumed to equal the average of such temperatures over the estimation interval. For the months of January and August, the average daily temperature producing the monthly peak is assumed to equal the average daily temperature, over the estimation interval, producing the winter or summer peaks, respectively. In this manner, the forecast assumes that the Company's winter peak will occur in January and that its summer peak will occur in August.

The peak internal demand for the AEP System is calculated from the monthly peaks of the companies, adjusted for diversity.

E. LOAD FORECAST RESULTS

E.1. Load Forecast Before DSM Adjustments (Base Forecast)

Exhibit 2-5 present KPCo's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial and other internal sales, as well as losses) on an actual basis for the years 1994-1998 and on a forecast basis for the years 1999-2019. The exhibit also shows annual growth rates for both the historical and forecast periods. Corresponding information for the AEP System is given on Exhibit 2-6.

Exhibits 2-7 and 2-8 show, for KPCo and the AEP System, respectively, actual and forecasted summer, winter and annual peak internal demands, along with annual total energy requirements. Also shown are the associated growth rates and annual load factors.

Exhibit 2-9 shows further disaggregation of KPCo's forecasted annual internal energy requirements, along with the associated summer and winter peak demands. Exhibits 2-10 and 2-11 show, for the first two years of the forecast period, i.e., 1999 and 2000, KPCo's disaggregated energy requirements on a monthly basis, along with monthly peak demands.

E.2. Load Forecast After DSM Adjustments

Exhibit 2-12 lists the DSM adjustments (discussed in Chapter 3) that were used to reduce the base forecasts of internal energy requirements and seasonal peak internal demands for both the AEP System and KPCo. The resulting forecasts, which reflect these adjustments, are presented in Exhibits 2-13 through 2-19, in the same order as Exhibits 2-5 to 2-11.

F. IMPACT OF CONSERVATION AND DEMAND-SIDE MANAGEMENT

Since the mid-1970s, conservation, caused in part by higher energy prices and in part by Company-sponsored conservation and DSM programs, has reduced the rate of growth of energy sales and peak demand on the entire AEP System and its operating companies.

Higher energy prices have stimulated technological improvements in the energy efficiency of new electric appliances and industrial machinery, and in the thermal integrity of residential and commercial structures. The effect of these improvements has been to decrease average electricity consumption per customer. It is also believed that higher energy prices have had the effect of inducing a permanent change in consumer attitudes toward energy conservation, which has tended to reduce average energy consumption at all levels of price and technological development. The sudden and dramatic increase in energy prices caused by the 1973-74 oil embargo, for example, is thought to have altered the level of conservation awareness among consumers, making a large segment of the consuming public much more conscious of its energy use and its options for conserving.

The Company has recognized both its responsibility to encourage its customers to make wise use of all energy resources, and its expertise in the field of energy consumption planning, and has for some years pursued the policy of providing its customers with opportunities to use energy wisely. It has done so through both educational programs and active promotional programs aimed at broad customer groups. And, through its DSM programs, the Company has maintained an active interest and participation in various programs for improving the cost-effectiveness of customer electricity use. Descriptions of the Company's efforts in this regard are given in Chapter 3 of this report.

As for the load forecast, the impact of conservation on load is captured by the inclusion of energy price variables in the forecasting equations. The impact of past customer conservation and load management activities, including embedded DSM installations, is part of the historical record of electricity use, and, in that sense, is intrinsically reflected in the load forecast. As already noted in the preceding section E.2, the load impacts of expanded DSM installations are analyzed and projected separately, and appropriate adjustments are made to the base load forecast.

No explicit adjustments were made to the forecast to account for national appliance efficiency standards or the National Energy Policy Act of 1992. Historically, such legislation and standards have established policies and programs for promoting energy conservation. To the extent that these policies and programs have already been implemented, their effects are intrinsically reflected in the load forecast.

G. ENERGY-PRICE RELATIONSHIPS

An understanding of the relationship between energy prices and energy consumption is crucial to developing a forecast of electricity consumption. In theory, the effect of a change in the price of a good on the consumption of that good can be decomposed into two effects, the "income" effect and the "substitution" effect. The income effect refers to the change in consumption of a good attributable to the change in real income incident to the change in the price of that good. For most goods, a decline in real income would induce a decline in consumption. The substitution effect refers to the change in the consumption of a good associated with the change in the price of that good relative to the prices of all other goods. The substitution effect is assumed to be negative in all cases; that is, a rise in the price of a good relative to other, substitute goods would induce a decline in consumption of the original good. Thus, if the price of electricity were to rise, the consumption of electricity would fall, all other things being equal. Part of the decline would be attributable to the income effect; consumers effectively have less income after the price of electricity rises, and part would be attributable to the substitution effect; consumers would substitute relatively cheaper fuels for electricity once its price had risen.

The magnitude of the effect of price changes on consumption differs over different time horizons. In the short-term, the effect of a rise in the price of electricity is severely constrained by the ability of consumers to substitute other fuels or to incorporate more electricity-efficient technology. (The fact that the Company's short-term energy consumption models do not include price as an explanatory variable is a reflection of the belief that this constraint is severe).

In the long-term, however, the constraints on substitution are lessened for a number of reasons. First, durable equipment stocks begin to reflect changes in relative energy prices by favoring the equipment using the fuel that was expected to be cheaper; second, heightened consumer interest in saving electricity, backed by willingness to pay for more efficiency, spurs development of conservation technology; third, existing technology, too expensive to implement commercially at previous levels of energy prices, becomes feasible at the new, higher energy prices; and fourth, normal turnover of electricity-using equipment contributes to a higher average level of energy efficiency. For these reasons, energy price changes are expected to have an effect on long-term energy consumption levels. As a reflection of this belief, most of the Company's long-term forecasting models, including the residential, commercial, manufacturing and mine power energy sales models, directly incorporate the price of electricity as an explanatory variable. In these cases, the coefficient of the price variable provides a quantitative measure of the sensitivity of the forecast value to a change in price. Some of the models, including the residential, commercial and manufacturing models, also incorporate the price of natural gas to consumers in the state of Kentucky.

Electricity price projections for KPCo are based on two different assumptions governing two different forecast horizons. Through 2003, prices are assumed to be held constant in nominal dollars, i.e., they are expected to decline by the rate of inflation. Beyond 2003, nominal prices are assumed to rise at the expected rate of inflation, thus keeping real prices constant. Given these assumptions, projected electricity prices are expected to fall at an average annual rate of 0.6% for KPCo customers during the period 1999-2019. Natural gas prices to consumers in the state of Kentucky, based on the forecasting model described earlier, are expected to rise by 0.3 % per year during the same period.

H. FORECAST UNCERTAINTY AND RANGE OF FORECASTS

Even though load forecasts are created individually for each of the operating companies in the AEP System, and aggregated to form the System total, forecast uncertainty is of primary interest at the System level, rather than the operating company level. Thus, regardless of how forecast uncertainty is characterized, the analysis begins with AEP System load.

Among the ways to characterize forecast uncertainty are: (1) the establishment of confidence intervals that are defined so as to contain a given percentage of possible outcomes, and (2) the development of high- and low-case scenarios that demonstrate the response of forecasted load to changes in driving force variables. AEP continues to support both approaches to analyzing forecast uncertainty; however, for the purposes of this report, scenarios were used for the sensitivity analyses conducted for capacity planning purposes.

The first step in producing high- and low-case scenarios was the estimation of an aggregated "mini-model" of AEP System internal energy requirements. This approach was deemed more feasible than attempting to calculate high and low cases for each of the many equations used to produce the Company's load forecast. The mini-model is intended to be representative of the full forecasting structure employed in producing the base-case forecast for the AEP System, and, by association, for KPCo. The dependent variable is total AEP System internal energy requirements, excluding sales to the System's two aluminum reduction plants. This aluminum load is a large and volatile component of total load which, as mentioned earlier in this report, is treated judgmentally, not analytically, in the load forecast. It is simply added back, as appropriate, to the alternative forecasts produced by the mini-model to create low- and high-case scenarios for total internal energy requirements. The independent variables are real GDP, AEP service-area employment, the average real price of electricity to all AEP customer classes, the average real price of natural gas in the seven states served by AEP, and AEP service-area heating and cooling degree-days. All variables except degree-days are expressed in logarithms. Acceptance of this particular specification is based on the usual statistical tests of goodness-of-fit, on the reasonableness of the elasticities derived from the estimation, and on a rough agreement between the model's load prediction and that produced by the disaggregated modeling approach followed in producing the load forecast.

Once a base-case energy forecast had been produced with the mini-model, low and high values for the independent variables were determined. The values finally decided upon reflect professional judgment. The low- and high-case growth rates in real GDP for the forecast period were 1.6% and 2.8% per year, respectively, compared to 2.4% for the base case. The low- and high-case growth rates for AEP-region total employment were 0.6% and 1.9% per year, respectively, compared to 1.3% per year for the base case. For the real price of natural gas, the low case assumed a growth rate of 0.5% per year, and the high case assumed a growth rate of 1.7% per year. These compare to a base-case growth rate of 1.0% for the average real gas price in the seven states served by AEP. Electricity price was not varied, the assumption being that variation in the price of natural gas in the high and low cases would serve to represent a change in the relative price of the two fuels. Variations in weather were not considered in this analysis; so the value of heating and cooling degree-days remained the same in all cases.

The low-case, base-case and high-case forecasts of summer and winter peak demands and total energy requirements (before DSM adjustments) for the AEP System and KPCo are tabulated in Exhibits 2-20 and 2-21, respectively. Graphical displays of the range of forecasts of internal energy requirements and summer peak demand for KPCo are shown in Exhibit 2-22.

For AEP, the low-case and high-case energy forecasts for the last forecast year, 2019, represent deviations of about 9% below and above, respectively, from the base-case forecast (with the corresponding KPCo forecast showing about the same percentage deviation). In this regard, the low-case and high-case growth rates in summer peak internal demand for the forecast period were 1.0% and 1.8% per year, respectively, compared to 1.4% per year in the base case.

The corresponding range of load forecasts reflecting DSM adjustments are shown in Exhibits 2-23 (for the AEP System) and 2-24 (for KPCo).

I. SIGNIFICANT CHANGES FROM PREVIOUS FORECAST

I.1. Energy Forecast

Exhibit 2-25 provides a tabular comparison of the 1996 and 1999 forecasts of total internal energy requirements (before DSM adjustments) for both KPCo and the AEP System. Exhibit 2-26 shows the comparison for KPCo in graphical form. As these exhibits indicate, KPCo's

1999 energy forecast is initially lower than the 1996 forecast, but in the long term becomes slightly higher, in terms of magnitude (71 GWh, or 0.7%, higher for year 2016) and long-term average annual growth rate (1.7% vs. 1.6%). For the AEP System, the 1999 forecast for year 2016 is 1.9% less than the 1996 forecast, while the long-term growth rate for the 1999 forecast is slightly lower than for the 1996 forecast (1.2% vs. 1.3%).

An examination of the sectoral changes in the forecast may provide a better understanding of the changes in the aggregate forecast. The forecasted levels of the sectoral components for the year 2016 did not change uniformly with the 0.7% increase in the forecast of total energy requirements. Specifically, the residential and commercial energy sales forecasts were increased by 7.8% and 11.0%, respectively, while the manufacturing and mine power sales forecasts were decreased by 3.4% and 7.8%, respectively.

Factors contributing to the increase in the residential and commercial energy sales forecasts include the use of an alternative regional economic forecast (i.e., the forecast by Woods & Poole Economics) and a re-evaluation of expected long-term trends in residential and commercial consumption patterns in light of what has been experienced historically. The changed assumptions reflect the effect of updated information obtained or developed since the 1996 forecast, along with changing perceptions of the future.

For the manufacturing sector, the overriding factor contributing to the decrease in the energy sales forecast is that the anticipated load additions at existing and new facilities within the service area were not as large as expected.

Also, the mine power energy sales forecast was adjusted downward, to better reflect energy consumption patterns being experienced at the time of the forecast's development. One major factor affecting the coal industry is the continued shift of production from eastern states to western states. Part of this shift can be attributed to the needs for lower sulfur coal by power plants, in order to be in compliance with the Phase II requirements of the 1990 Clean Air Act Amendments.

I.2. Peak Internal Demand Forecast

Exhibit 2-27 provides a tabular comparison of the 1996 and 1999 forecasts of the winter peak internal demand (before DSM adjustments) for both KPCo and the AEP System. This exhibit indicates that for the winter of 2016/17, KPCo's 1999 peak demand forecast is 0.6% higher than the 1996 forecast. This increase reflects the change in the forecast for total energy requirements.

In the case of the AEP System, for the winter of 2016/17, the 1999 forecast is 0.3% lower than the 1996 forecast. This change reflects the reassessment of peak demand forecasts since 1996.

I.3. Forecasting Methodology

Opportunities to enhance forecasting methods are explored by KPCo on a continuing basis. In this regard, there were no major changes in the basic forecast methodology since 1996. However, some important changes have since occurred.

In the first place, RFA has replaced DRI as the Company's source for the national economic forecast. Secondly, the regional economic forecast is now acquired from Woods & Poole Economics, rather than being developed in-house.

Thirdly, the manufacturing sector is now modeled in aggregate, rather than by major SIC category. There have also been changes in the explanatory variables in the various forecast models.

J. ADDITIONAL LOAD INFORMATION

Additional information provided for the purposes of this report includes the following:

Exhibit 2-28: KPCo, Average Annual Number of Customers by Class, 1994-1998.

Exhibit 2-29: KPCo, Annual Internal Load by Class (GWh), 1994-1998.

Exhibit 2-30: KPCo and AEP System, Recorded and Weather-Normalized Peak Internal Load (MW) and Energy Requirements (GWh), 1994-1998.

Exhibit 2-31: AEP System and KPCo, Profiles of Monthly Peak Internal Demands, 1993, 1998 (Actual), 2008 and 2018.

The historical profiles presented in Exhibit 2-31 have not been adjusted to reflect normal weather patterns and, therefore, may vary to some degree from the forecast patterns projected for 2008 and 2018. These patterns also reflect the expectation that KPCo will continue to experience its annual peak demand in the winter season, while AEP's annual peak is expected to occur in the summer.

K. DATA-BASE SOURCES

Sources from within the Company that were used in developing the Company's load forecasts are as follows: (1) Sales for Resale Reports (Form ST-18), (2) daily, monthly and annual System Operation Department reports, (3) monthly financial reports, (4) monthly kWh and revenue SIC reports, and (5) residential tariff schedules and fuel clause summaries for all operating companies.

The data sources from outside the company are varied and include state and federal agencies, as well as RFA and Woods & Poole Economics. Exhibit 2-32 identifies the data series and associated sources, along with notes on adjustments made to the data before incorporation into the load forecasting models.

L. OTHER TOPICS

L.1. Residential Energy Sales Forecast Performance

Exhibit 2-33 provides a comparison of actual vs. the 1996 forecast of KPCo's residential energy sales for the years 1996-1998. In 1996 and 1997, KPCo's residential energy sales were higher than forecast, by 2.7% and 0.7%, respectively. In 1998, such sales were 3.0% less than forecast. A major factor contributing to the deviations from forecast was the weather. In 1996, heating degree-days were 4.6% above normal, thus causing greater-than-expected energy sales in that year. Conversely, 1998 saw heating degree-days 17% below normal, which resulted in residential energy sales being less than expected.

L.2. Peak Demand Forecast Performance

Exhibit 2-34 provides a comparison of actual vs. the 1996 forecast of KPCo's seasonal internal peak demands for 1996-1998. The exhibit also compares the calculated weather-normalized demands with the forecast values, thus indicating the extent to which weather affected actual demands.

KPCo's winter peak demand forecasts were close to the actual experience, with the exception of the winter of 1997/98. For that season, KPCo's actual peak demand was 8.6% less than forecast as a result of the occurrence of very mild weather.

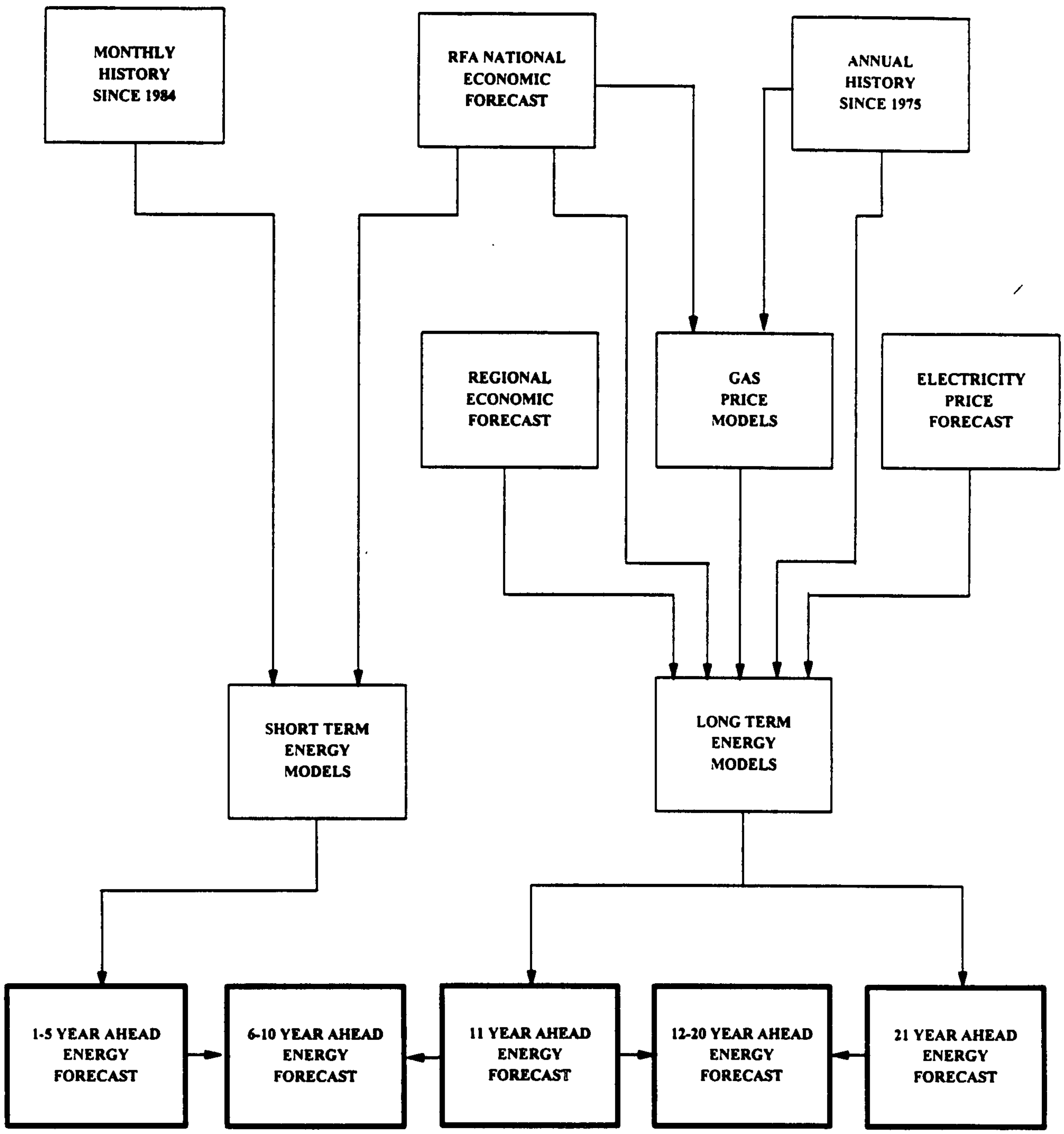
Also, KPCo's actual and weather-normalized summer peak demands were below forecast for each year in the period 1996-1998. As a result, KPCo's summer peak demand forecast was revised downward for the short-term.

L.3. Other Scenario Analyses

At the time the Company's current load forecast was developed, no clear policy guidelines existed or were developed with respect to more stringent NOx emissions requirements. This situation continues to prevail today. Accordingly, the Company has not conducted analyses nor speculated on the possible effects of these potentially more stringent requirements on energy prices or on the load forecast.

Similarly, when the current forecast was developed, there were, and there continues to be, no definitive and comprehensive plan for deregulation of the electric utility industry. Therefore, the forecast was developed as a business-as-usual scenario, with no alternative scenarios being created that would speculate as to the nature of the outcome of industry deregulation.

KENTUCKY POWER COMPANY
INTERNAL ENERGY REQUIREMENTS FORECASTING METHOD

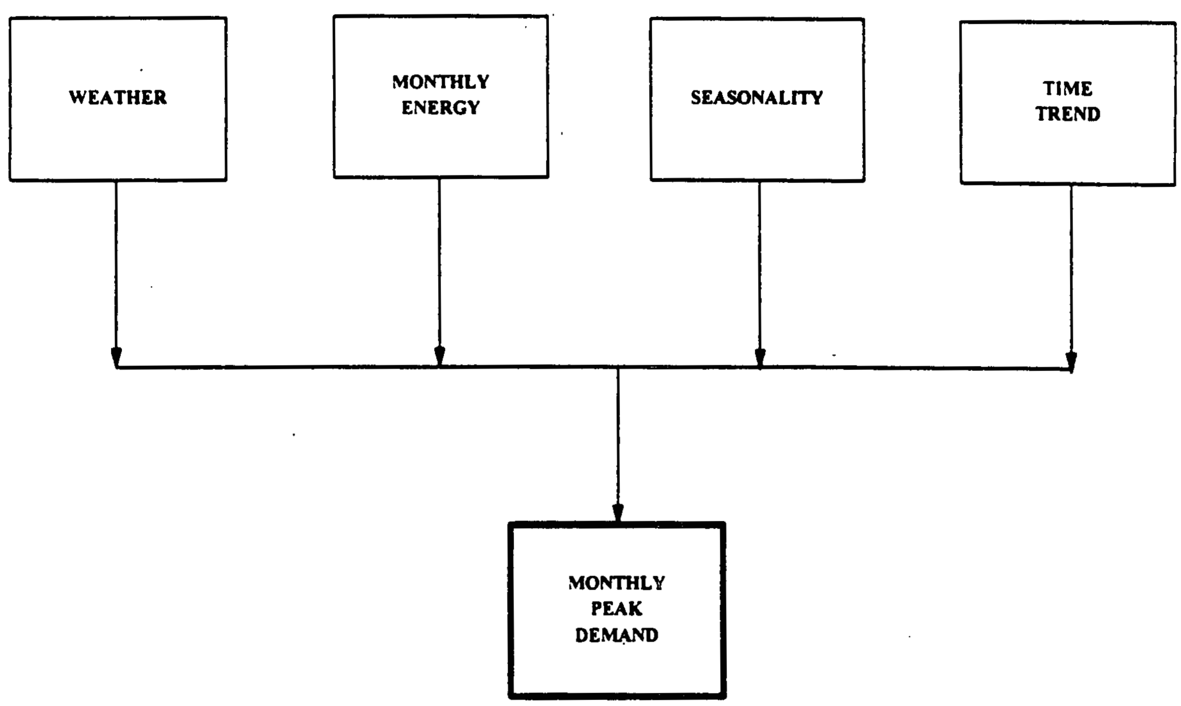


KENTUCKY POWER COMPANY
VARIABLES EMPLOYED IN FORECAST MODELS OF ENERGY SALES

	Residential Customers		Residential Energy Sales		Commercial Energy Sales		Manufacturing Energy Sales		Mine Power Energy Sales		All Other Energy Sales	
Variable	Short Term	Long Term	Short Term	Long Term	Short Term	Long Term	Short Term	Long Term	Short Term	Long Term	Short Term	Long Term
Binary	X	X	X	X	X	X	X	X	X		X	X
Time Trend	X		X		X		X		X		X	X
Electricity Price				X		X		X		X		
Natural Gas Price				X		X		X				
Residential Customers				X								
Per Capita Income						X						
Service Area Employment		X		X								
Heating Degree-Days			X	X	X		X		X		X	
Cooling Degree-Days			X	X	X	X	X		X		X	
Commercial Employment						X						
FRB Industrial Production Index							X	X				
Manufacturing Employment								X				
Coal Production										X		

Exhibit 2-2

KENTUCKY POWER COMPANY
PEAK INTERNAL DEMAND FORECASTING METHOD



Kentucky Power Company
Values of Variables Employed in the Long-Term Forecasts of
Residential and Commercial Energy Sales
1975, 1997 and 2019

	Actual		Forecast	Average Annual Growth Rate - %	
	1975	1997	Base 2019	1975-1997	2009-2019
Residential Energy Sales					
1. Service Area Employment	118,616	157,928	194,977	1.3	1.0
Residential Customers	106,399	142,197	170,945	1.3	0.8
1. Cooling Degree Days - Huntington, West Virginia	1,274	839	1,005	-1.9	0.8
2. Heating Degree Days - Huntington, West Virginia	4,249	4,707	4,665	0.5	0.0
3. Service Area Employment	118,616	157,928	194,977	1.3	1.0
4. Real Residential Electricity Price Index (1997=1.00)	1.54	1.00	0.85	-1.9	-0.7
5. Real Kentucky Residential Gas Price Index (1997=1.00)	0.57	1.00	0.98	2.6	-0.1
Residential Energy Sales (GWH)	972	2,197	3,390	3.8	2.0
Commercial Energy Sales					
1. Service Area Real Personal Income Per Capita (1992 $)	11,301	14,574	19,048	1.2	1.2
2. Service Area Commerical Employment	62,210	102,209	134,120	2.3	1.2
3. Cooling Degree Days - Huntington, West Virginia	1,274	839	1,005	-1.9	0.8
4. Real Commercial Electricity Price Index (1997=1.00)	1.53	1.00	0.85	-1.9	-0.7
5. Real Kentucky Commercial Gas Price Index (1997=1.00)	1.83	1.00	0.98	-2.7	-0.1
Commercial Energy Sales (GWH)	1,041	2,031	2,587	3.1	1.1

Kentucky Power Company
Values of Variables Employed in the Long-Term Forecasts for
Manufacturing and Mine Power Energy Sales
1975, 1997 and 2019

	Actual		Forecast	Average Annual Growth Rate-%	
	1975	1997	Base 2019	1975-1997	1997-2019
Manufacturing Energy Sales					
1. FRB Industrial Production Index for Manufacturing (1992=100)	59.4	126.9	229.7	3.5	2.7
2. Service Area Manufacturing Employment	13,975	12,118	12,601	-0.6	0.2
3. Real Manufacturing Electricity Price Index (1997=1.00)	1.29	1.00	0.85	-1.2	-0.7
4. Real Kentucky Manufacturing Gas Price Index (1997=1.00)	0.37	1.00	0.96	4.6	-0.2
Manufacturing Energy Sales (GWH)	1,041	2,031	2,587	3.1	1.1
Mine Power Energy Sales					
1. Service Area Coal Production (Million Tons)	61.2	104.5	131.3	2.5	1.0
2. Real Manufacturing Electricity Price Index (1997=1.00)	1.81	1.00	0.85	-2.7	-0.7
Mine Power Energy Sales (GWH)	405	1,111	1,452	4.7	1.2

KENTUCKY POWER COMPANY
ANNUAL INTERNAL ENERGY REQUIREMENTS AND GROWTH RATES
1994-2019

BEFORE DSM ADJUSTMENTS

	RESIDENTIAL SALES		COMMERCIAL SALES		INDUSTRIAL SALES		OTHER INTERNAL SALES		LOSSES		TOTAL INTERNAL ENERGY REQUIREMENTS	
	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH
ACTUAL												
1994	2,025	-	1,072	-	2,870	-	83	-	433	-	6,483	-
1995	2,192	8.2	1,135	5.9	2,980	3.8	88	6.0	413	-4.6	6,808	5.0
1996	2,191	-0.0	1,150	1.3	3,076	3.2	93	5.7	450	9.0	6,960	2.2
1997	2,197	0.3	1,166	1.4	3,142	2.1	88	-5.4	304	-32.4	6,897	-0.9
1998	2,156	-1.9	1,195	2.5	3,131	-0.4	91	3.4	419	37.8	6,992	1.4
FORECAST												
1999	2,315	7.4	1,255	5.0	3,189	1.9	91	0.0	447	6.7	7,297	4.4
2000	2,363	2.1	1,291	2.9	3,217	0.9	91	0.0	444	-0.7	7,406	1.5
2001	2,409	1.9	1,327	2.8	3,244	0.8	92	1.1	452	1.8	7,524	1.6
2002	2,454	1.9	1,363	2.7	3,271	0.8	93	1.1	451	-0.2	7,632	1.4
2003	2,499	1.8	1,399	2.6	3,298	0.8	95	2.2	455	0.9	7,746	1.5
2004	2,554	2.2	1,439	2.9	3,345	1.4	98	3.2	459	0.9	7,895	1.9
2005	2,610	2.2	1,479	2.8	3,391	1.4	101	3.1	464	1.1	8,045	1.9
2006	2,666	2.1	1,520	2.8	3,437	1.4	103	2.0	468	0.9	8,194	1.9
2007	2,722	2.1	1,560	2.6	3,483	1.3	106	2.9	472	0.9	8,343	1.8
2008	2,777	2.0	1,600	2.6	3,530	1.3	110	3.8	476	0.8	8,493	1.8
2009	2,833	2.0	1,640	2.5	3,576	1.3	112	1.8	481	1.1	8,642	1.8
2010	2,889	2.0	1,680	2.4	3,622	1.3	116	3.6	485	0.8	8,792	1.7
2011	2,944	1.9	1,721	2.4	3,669	1.3	118	1.7	489	0.8	8,941	1.7
2012	3,000	1.9	1,761	2.3	3,715	1.3	121	2.5	493	0.8	9,090	1.7
2013	3,056	1.9	1,801	2.3	3,761	1.2	124	2.5	498	1.0	9,240	1.7
2014	3,112	1.8	1,841	2.2	3,807	1.2	127	2.4	502	0.8	9,389	1.6
2015	3,167	1.8	1,881	2.2	3,854	1.2	130	2.4	506	0.8	9,538	1.6
2016	3,223	1.8	1,921	2.1	3,900	1.2	133	2.3	511	1.0	9,688	1.6
2017	3,279	1.7	1,962	2.1	3,946	1.2	135	1.5	515	0.8	9,837	1.5
2018	3,335	1.7	2,002	2.0	3,992	1.2	139	3.0	519	0.8	9,987	1.5
2019	3,390	1.6	2,042	2.0	4,039	1.2	142	2.2	523	0.8	10,136	1.5
AVERAGE ANNUAL GROWTH RATES:												
1994-1998		1.6		2.8		2.2		2.3		-0.8		1.9
1999-2019		1.9		2.5		1.2		2.2		0.8		1.7

AMERICAN ELECTRIC POWER SYSTEM
ANNUAL INTERNAL ENERGY REQUIREMENTS AND GROWTH RATES
1994-2019

BEFORE DSM ADJUSTMENTS

	RESIDENTIAL SALES		COMMERCIAL SALES		INDUSTRIAL SALES		OTHER INTERNAL SALES		LOSSES		TOTAL INTERNAL ENERGY REQUIREMENTS	
	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH
ACTUAL												
1994	28,818	-	21,209	-	43,856	-	7,702	-	7,688	-	109,273	-
1995	30,620	6.3	22,190	4.6	44,607	1.7	7,819	1.5	8,146	6.0	113,382	3.8
1996	30,854	0.8	22,558	1.7	45,676	2.4	7,993	2.2	8,867	8.9	115,948	2.3
1997	30,283	-1.9	22,720	0.7	46,584	2.0	8,061	0.9	8,488	-4.3	116,136	0.2
1998	30,414	0.4	23,599	3.9	47,298	1.5	6,618	-17.9	9,142	7.7	117,071	0.8
FORECAST												
1999	32,223	5.9	24,394	3.4	48,077	1.6	5,087	-23.1	8,929	-2.3	118,710	1.4
2000	32,876	2.0	24,958	2.3	44,226	-8.0	5,100	0.3	8,956	0.3	116,116	-2.2
2001	33,546	2.0	25,523	2.3	44,896	1.5	5,219	2.3	9,021	0.7	118,205	1.8
2002	34,209	2.0	26,087	2.2	45,555	1.5	5,343	2.4	9,074	0.6	120,268	1.7
2003	34,873	1.9	26,650	2.2	46,232	1.5	5,466	2.3	9,137	0.7	122,358	1.7
2004	35,490	1.8	27,177	2.0	46,711	1.0	5,580	2.1	9,210	0.8	124,168	1.5
2005	36,108	1.7	27,704	1.9	47,191	1.0	5,693	2.0	9,282	0.8	125,978	1.5
2006	36,725	1.7	28,231	1.9	47,670	1.0	5,807	2.0	9,355	0.8	127,788	1.4
2007	37,342	1.7	28,758	1.9	48,149	1.0	5,921	2.0	9,428	0.8	129,598	1.4
2008	37,959	1.7	29,285	1.8	48,629	1.0	6,034	1.9	9,501	0.8	131,408	1.4
2009	38,577	1.6	29,813	1.8	49,108	1.0	6,147	1.9	9,574	0.8	133,219	1.4
2010	39,194	1.6	30,340	1.8	49,588	1.0	6,260	1.8	9,647	0.8	135,029	1.4
2011	39,811	1.6	30,867	1.7	50,067	1.0	6,374	1.8	9,720	0.8	136,839	1.3
2012	40,429	1.6	31,394	1.7	50,547	1.0	6,486	1.8	9,793	0.8	138,649	1.3
2013	41,046	1.5	31,921	1.7	51,026	0.9	6,601	1.8	9,865	0.7	140,459	1.3
2014	41,663	1.5	32,448	1.7	51,505	0.9	6,715	1.7	9,938	0.7	142,269	1.3
2015	42,280	1.5	32,975	1.6	51,985	0.9	6,828	1.7	10,011	0.7	144,079	1.3
2016	42,898	1.5	33,503	1.6	52,464	0.9	6,940	1.6	10,084	0.7	145,889	1.3
2017	43,515	1.4	34,030	1.6	52,944	0.9	7,054	1.6	10,157	0.7	147,700	1.2
2018	44,132	1.4	34,557	1.5	53,423	0.9	7,168	1.6	10,230	0.7	149,510	1.2
2019	44,749	1.4	35,084	1.5	53,903	0.9	7,281	1.6	10,303	0.7	151,320	1.2
AVERAGE ANNUAL GROWTH RATES:												
1994-1998		1.4		2.7		1.9		-3.7		4.4		1.7
1999-2019		1.7		1.8		0.6		1.8		0.7		1.2

KENTUCKY POWER COMPANY
SEASONAL AND ANNUAL PEAK DEMANDS, ENERGY REQUIREMENTS AND LOAD FACTOR
1994-2019

BEFORE DSM ADJUSTMENTS

	SUMMER PEAK			WINTER PEAK (1)			ANNUAL PEAK, ENERGY AND LOAD FACTOR				
	DATE	MW	% GROWTH	DATE	MW	% GROWTH	MW	% GROWTH	GWH	% GROWTH	LOAD FACTOR (%)
ACTUAL											
1994	06/20/94	1,079	-	02/09/95	1,363	-	1,309	-	6,483	-	56.5
1995	08/15/95	1,136	5.3	02/05/96	1,418	4.0	1,363	4.1	6,808	5.0	57.0
1996	08/07/96	1,087	-4.3	01/17/97	1,417	-0.1	1,418	4.0	6,960	2.2	56.0
1997	07/28/97	1,164	7.1	03/13/98	1,299	-8.3	1,417	-0.1	6,897	-0.9	55.6
1998	08/25/98	1,213	4.2	01/05/99	1,432	10.2	1,299	-8.3	6,992	1.4	61.4
FORECAST											
1999		1,231	1.5		1,462	2.1	1,462	12.5	7,297	4.4	57.0
2000		1,250	1.5		1,488	1.8	1,488	1.8	7,406	1.5	56.8
2001		1,270	1.6		1,512	1.6	1,512	1.6	7,524	1.6	56.8
2002		1,291	1.7		1,537	1.7	1,537	1.7	7,632	1.4	56.7
2003		1,312	1.6		1,570	2.1	1,570	2.1	7,746	1.5	56.3
2004		1,336	1.8		1,602	2.0	1,602	2.0	7,895	1.9	56.3
2005		1,361	1.9		1,635	2.1	1,635	2.1	8,045	1.9	56.2
2006		1,385	1.8		1,667	2.0	1,667	2.0	8,194	1.9	56.1
2007		1,410	1.8		1,699	1.9	1,699	1.9	8,343	1.8	56.1
2008		1,434	1.7		1,732	1.9	1,732	1.9	8,493	1.8	56.0
2009		1,459	1.7		1,764	1.8	1,764	1.8	8,642	1.8	55.9
2010		1,484	1.7		1,796	1.8	1,796	1.8	8,792	1.7	55.9
2011		1,508	1.6		1,829	1.8	1,829	1.8	8,941	1.7	55.8
2012		1,533	1.7		1,861	1.7	1,861	1.7	9,090	1.7	55.8
2013		1,557	1.6		1,894	1.8	1,894	1.8	9,240	1.7	55.7
2014		1,582	1.6		1,926	1.7	1,926	1.7	9,389	1.6	55.6
2015		1,607	1.6		1,958	1.7	1,958	1.7	9,538	1.6	55.6
2016		1,631	1.5		1,991	1.7	1,991	1.7	9,688	1.6	55.5
2017		1,656	1.5		2,023	1.6	2,023	1.6	9,837	1.5	55.5
2018		1,680	1.4		2,056	1.6	2,056	1.6	9,987	1.5	55.5
2019		1,705	1.5		2,090	1.7	2,090	1.7	10,136	1.5	55.4
AVERAGE ANNUAL GROWTH RATES:											
1994-1998			3.0			1.2		-0.2		1.9	
1999-2019			1.6			1.8		1.8		1.7	

Note : (1) Actual winter peak for year may occur in the 4th quarter of that year or in the 1st quarter of the following year.

Exhibit 2-8

AMERICAN ELECTRIC POWER SYSTEM
SEASONAL AND ANNUAL PEAK DEMANDS, ENERGY REQUIREMENTS AND LOAD FACTOR
1994-2019

BEFORE DSM ADJUSTMENTS

	SUMMER PEAK			WINTER PEAK (1)			ANNUAL PEAK, ENERGY AND LOAD FACTOR				
	DATE	MW	% GROWTH	DATE	MW	% GROWTH	MW	% GROWTH	GWH	% GROWTH	LOAD FACTOR (%)
ACTUAL											
1994	06/20/94	18,070	-	02/09/95	18,633	-	19,236	-	109,273	-	64.8
1995	08/14/95	19,516	8.0	02/05/96	19,557	5.0	19,516	1.5	113,382	3.8	66.3
1996	08/07/96	18,864	-3.3	01/17/97	19,381	-0.9	19,557	0.2	115,948	2.3	67.7
1997	07/14/97	19,119	1.4	03/13/98	17,841	-7.9	19,381	-0.9	116,136	0.2	68.4
1998	07/21/98	19,414	1.5	01/05/99	18,546	4.0	19,414	0.2	117,071	0.8	68.8
FORECAST											
1999		19,795	2.0		19,082	2.9	19,795	2.0	118,710	1.4	68.5
2000		19,727	-0.3		19,372	1.5	19,727	-0.3	116,116	-2.2	67.2
2001		20,060	1.7		19,660	1.5	20,060	1.7	118,205	1.8	67.3
2002		20,407	1.7		19,955	1.5	20,407	1.7	120,268	1.7	67.3
2003		20,757	1.7		20,244	1.4	20,757	1.7	122,358	1.7	67.3
2004		21,088	1.6		20,533	1.4	21,088	1.6	124,168	1.5	67.2
2005		21,419	1.6		20,821	1.4	21,419	1.6	125,978	1.5	67.1
2006		21,750	1.5		21,110	1.4	21,750	1.5	127,788	1.4	67.1
2007		22,080	1.5		21,399	1.4	22,080	1.5	129,598	1.4	67.0
2008		22,411	1.5		21,687	1.3	22,411	1.5	131,408	1.4	66.9
2009		22,742	1.5		21,976	1.3	22,742	1.5	133,219	1.4	66.9
2010		23,073	1.5		22,265	1.3	23,073	1.5	135,029	1.4	66.8
2011		23,403	1.4		22,553	1.3	23,403	1.4	136,839	1.3	66.7
2012		23,734	1.4		22,842	1.3	23,734	1.4	138,649	1.3	66.7
2013		24,065	1.4		23,131	1.3	24,065	1.4	140,459	1.3	66.6
2014		24,395	1.4		23,419	1.2	24,395	1.4	142,269	1.3	66.6
2015		24,726	1.4		23,708	1.2	24,726	1.4	144,079	1.3	66.5
2016		25,057	1.3		23,997	1.2	25,057	1.3	145,889	1.3	66.5
2017		25,388	1.3		24,285	1.2	25,388	1.3	147,700	1.2	66.4
2018		25,718	1.3		24,574	1.2	25,718	1.3	149,510	1.2	66.4
2019		26,049	1.3		24,873	1.2	26,049	1.3	151,320	1.2	66.3
AVERAGE ANNUAL GROWTH RATES:											
1994-1998			1.8			-0.1		0.2		1.7	
1999-2019			1.4			1.3		1.4		1.2	

Note : (1) Actual winter peak for year may occur in the 4th quarter of that year or in the 1st quarter of the following year.

KENTUCKY POWER COMPANY
ANNUAL INTERNAL LOAD
1999-2009

BEFORE DSM ADJUSTMENTS

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
INTERNAL ENERGY (GWH)											
RESIDENTIAL	2,315	2,363	2,409	2,454	2,499	2,554	2,610	2,666	2,722	2,777	2,833
COMMERCIAL	1,255	1,291	1,327	1,363	1,399	1,439	1,479	1,520	1,560	1,600	1,640
OTHER INDUSTRIAL	2,051	2,068	2,086	2,102	2,120	2,149	2,178	2,207	2,236	2,266	2,295
NONASSOC. MINE POWER	1,137	1,149	1,159	1,169	1,179	1,196	1,213	1,230	1,247	1,264	1,281
TOTAL INDUSTRIAL	3,189	3,217	3,244	3,271	3,298	3,345	3,391	3,437	3,483	3,530	3,576
STREET LIGHTING	11	11	11	11	11	11	11	12	12	12	12
TOTAL OTHER ULTIMATE	11	11	11	11	11	11	11	12	12	12	12
TOTAL ULTIMATE SALES	6,769	6,881	6,991	7,099	7,207	7,350	7,492	7,634	7,776	7,919	8,061
MUNICIPALS	80	81	82	83	83	86	89	92	95	98	100
TOTAL SALES FOR RESALE	80	81	82	83	83	86	89	92	95	98	100
TOTAL INTERNAL SALES	6,849	6,962	7,072	7,181	7,291	7,436	7,581	7,726	7,871	8,016	8,161
TOTAL LOSSES	447	444	452	451	455	459	464	468	472	476	481
TOTAL INTERNAL ENERGY	7,297	7,406	7,524	7,632	7,746	7,895	8,045	8,194	8,343	8,493	8,642
INTERNAL PEAK DEMAND (MW)											
SUMMER	1,231	1,250	1,270	1,291	1,312	1,336	1,361	1,385	1,410	1,434	1,459
PRECEDING WINTER	1,444	1,462	1,488	1,512	1,537	1,570	1,602	1,635	1,667	1,699	1,732

KENTUCKY POWER COMPANY
ANNUAL INTERNAL LOAD
2010-2019

BEFORE DSM ADJUSTMENTS

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
INTERNAL ENERGY (GWH)										
RESIDENTIAL	2,889	2,944	3,000	3,056	3,112	3,167	3,223	3,279	3,335	3,390
COMMERCIAL	1,680	1,721	1,761	1,801	1,841	1,881	1,921	1,962	2,002	2,042
OTHER INDUSTRIAL	2,324	2,353	2,382	2,411	2,441	2,470	2,499	2,528	2,557	2,587
NONASSOC. MINE POWER	1,298	1,315	1,333	1,350	1,367	1,384	1,401	1,418	1,435	1,452
TOTAL INDUSTRIAL	3,622	3,669	3,715	3,761	3,807	3,854	3,900	3,946	3,992	4,039
STREET LIGHTING	12	12	12	12	12	13	13	13	13	13
TOTAL OTHER ULTIMATE	12	12	12	12	12	13	13	13	13	13
TOTAL ULTIMATE SALES	8,203	8,346	8,488	8,630	8,773	8,915	9,057	9,199	9,342	9,484
MUNICIPALS	103	106	109	112	115	117	120	123	126	129
TOTAL SALES FOR RESALE	103	106	109	112	115	117	120	123	126	129
TOTAL INTERNAL SALES	8,307	8,452	8,597	8,742	8,887	9,032	9,177	9,322	9,468	9,613
TOTAL LOSSES	485	489	493	498	502	506	511	515	519	523
TOTAL INTERNAL ENERGY	8,792	8,941	9,090	9,240	9,389	9,538	9,688	9,837	9,987	10,136
INTERNAL PEAK DEMAND (MW)										
SUMMER	1,484	1,508	1,533	1,557	1,582	1,607	1,631	1,656	1,680	1,705
PRECEDING WINTER	1,764	1,796	1,829	1,861	1,894	1,926	1,958	1,991	2,023	2,056

KENTUCKY POWER COMPANY
MONTHLY INTERNAL LOAD
1999

BEFORE DSM ADJUSTMENTS

INTERNAL ENERGY (GWH)	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
RESIDENTIAL	275.6	223.8	196.2	155.2	143.1	161.2	202.8	195.6	156.2	154.3	199.2	251.4	2,315
COMMERCIAL	119.5	104.3	101.7	91.6	100.2	102.4	112.2	109.6	102.0	99.3	100.5	111.8	1,255
OTHER INDUSTRIAL	172.2	160.5	167.4	169.8	175.5	170.2	172.2	174.2	169.4	175.6	169.2	175.2	2,051
NONASSOC. MINE POWER	102.9	103.2	104.9	92.3	90.0	86.0	76.7	91.8	83.9	99.6	100.5	105.7	1,138
TOTAL INDUSTRIAL	275.2	263.8	272.3	262.1	265.5	256.3	248.8	266.0	253.2	275.2	269.7	280.9	3,189
STREET LIGHTING	1.1	0.9	0.9	0.8	0.8	0.7	0.8	0.8	0.8	1.0	1.0	1.1	11
TOTAL OTHER ULTIMATE	1.1	0.9	0.9	0.8	0.8	0.7	0.8	0.8	0.8	1.0	1.0	1.1	11
TOTAL ULTIMATE SALES	671.3	592.7	571.1	509.8	509.5	520.6	564.6	572.0	512.3	529.7	570.4	645.1	6,769
MUNICIPALS	8.3	7.2	7.0	5.2	6.2	6.2	6.5	7.9	5.7	5.7	6.6	7.7	80
TOTAL SALES FOR RESALE	8.3	7.2	7.0	5.2	6.2	6.2	6.5	7.9	5.7	5.7	6.6	7.7	80
TOTAL INTERNAL SALES	679.6	599.9	578.1	514.9	515.7	526.9	571.1	579.9	518.0	535.4	577.0	652.8	6,849
TOTAL LOSSES	43.7	39.6	38.4	33.4	31.0	31.8	37.7	36.3	35.1	37.0	39.0	44.4	447
TOTAL INTERNAL ENERGY	723.3	639.5	616.5	548.4	546.8	558.7	608.8	616.2	553.1	572.3	616.0	697.3	7,297
INTERNAL PEAK DEMAND (MW)	1,444	1,326	1,209	1,088	1,004	1,147	1,213	1,231	1,121	1,055	1,210	1,333	1,444

KENTUCKY POWER COMPANY
MONTHLY INTERNAL LOAD
2000

BEFORE DSM ADJUSTMENTS

INTERNAL ENERGY (GWH)	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
RESIDENTIAL	276.9	228.6	204.3	162.3	151.1	163.6	205.0	198.0	159.3	157.5	202.7	253.5	2,363
COMMERCIAL	121.9	107.0	104.9	94.5	102.9	105.7	115.3	112.5	105.2	102.4	103.4	114.9	1,291
OTHER INDUSTRIAL	173.3	161.6	168.6	171.2	176.9	171.7	173.7	175.7	170.9	177.2	170.8	176.8	2,068
NONASSOC. MINE POWER	105.0	103.2	105.9	93.2	91.3	86.7	77.6	92.9	84.5	100.5	101.3	106.7	1,149
TOTAL INDUSTRIAL	278.3	264.8	274.5	264.4	268.1	258.4	251.2	268.6	255.4	277.6	272.1	283.4	3,217
STREET LIGHTING	1.1	0.9	0.9	0.8	0.8	0.7	0.8	0.8	0.9	1.0	1.0	1.1	11
TOTAL OTHER ULTIMATE	1.1	0.9	0.9	0.8	0.8	0.7	0.8	0.8	0.9	1.0	1.0	1.1	11
TOTAL ULTIMATE SALES	678.2	601.4	584.7	521.9	522.9	528.4	572.3	580.0	520.7	538.5	579.3	652.9	6,881
MUNICIPALS	8.2	7.3	7.1	4.9	6.3	6.5	6.3	8.0	6.0	5.7	6.6	7.9	81
TOTAL SALES FOR RESALE	8.2	7.3	7.1	4.9	6.3	6.5	6.3	8.0	6.0	5.7	6.6	7.9	81
TOTAL INTERNAL SALES	686.4	608.6	591.7	526.8	529.2	535.0	578.6	587.9	526.7	544.2	585.8	660.8	6,962
TOTAL LOSSES	41.6	36.8	37.0	32.1	30.1	33.0	37.8	36.6	36.1	37.5	39.7	45.8	444
TOTAL INTERNAL ENERGY	727.9	645.4	628.8	558.9	559.3	567.9	616.4	624.5	562.8	581.7	625.5	706.5	7,406
INTERNAL PEAK DEMAND (MW)	1,462	1,345	1,236	1,109	1,027	1,168	1,232	1,250	1,141	1,071	1,230	1,355	1,462

Exhibit 2-12

AMERICAN ELECTRIC POWER SYSTEM
ESTIMATED DEMAND-SIDE MANAGEMENT IMPACTS
ON FORECASTED ENERGY REQUIREMENTS AND PEAK DEMANDS

	Energy Requirements Impacts GWH					Peak Demand Impacts MW	
Year	Residential	Commercial	Industrial	Losses	Total	Summer	Winter Following
1999	-5	0	0	-1	-6	-2	-11
2000	-16	0	0	-2	-18	-5	-21
2001	-25	0	0	-3	-28	-8	-30
2002	-36	0	0	-4	-40	-11	-40
2003	-45	0	0	-5	-50	-14	-50
2004	-56	0	0	-6	-62	-17	-61
2005	-62	0	0	-7	-69	-18	-61
2006	-62	0	0	-7	-69	-18	-61
2007	-62	0	0	-7	-69	-18	-61
2008	-62	0	0	-7	-69	-18	-60
2009	-62	0	0	-7	-69	-18	-60
2010	-61	0	0	-7	-68	-18	-60
2011	-61	0	0	-7	-68	-18	-60
2012	-61	0	0	-7	-68	-18	-60
2013	-59	0	0	-7	-66	-18	-60
2014	-58	0	0	-7	-65	-16	-49
2015	-48	0	0	-5	-53	-13	-40
2016	-39	0	0	-4	-43	-10	-30
2017	-29	0	0	-3	-32	-8	-30
2018	-29	0	0	-3	-32	-8	-30
2019	-29	0	0	-3	-32	-8	-30

KENTUCKY POWER COMPANY
ESTIMATED DEMAND-SIDE MANAGEMENT IMPACTS
ON FORECASTED ENERGY REQUIREMENTS AND PEAK DEMANDS

	Energy Requirements Impacts GWH					Peak Demand Impacts MW	
Year	Residential	Commercial	Industrial	Losses	Total	Summer	Winter Following
1999	-2	0	0	0	-2	0	-2
2000	-3	-1	0	0	-4	-1	-2
2001	-3	-1	0	0	-4	-1	-3
2002	-3	-1	0	-1	-5	-1	-4
2003	-4	-1	0	-1	-6	-1	-4
2004	-5	-1	0	-1	-7	-1	-5
2005	-5	-1	0	-1	-7	-2	-5
2006	-5	-1	0	-1	-7	-2	-5
2007	-5	-1	0	-1	-7	-2	-5
2008	-5	-1	0	-1	-7	-2	-5
2009	-5	-1	0	-1	-7	-2	-5
2010	-5	-1	0	-1	-7	-2	-5
2011	-5	-1	0	-1	-7	-2	-5
2012	-5	-1	0	-1	-7	-2	-5
2013	-5	-1	0	-1	-7	-2	-5
2014	-5	-1	0	-1	-7	-1	-3
2015	-3	-1	0	-1	-5	-1	-3
2016	-3	-1	0	0	-4	-1	-2
2017	-2	-1	0	0	-3	-1	-2
2018	-2	-1	0	0	-3	-1	-2
2019	-2	-1	0	0	-3	-1	-2

KENTUCKY POWER COMPANY
ANNUAL INTERNAL ENERGY REQUIREMENTS AND GROWTH RATES
1994-2019

REFLECTING DSM ADJUSTMENTS

	RESIDENTIAL SALES		COMMERCIAL SALES		INDUSTRIAL SALES		OTHER INTERNAL SALES		LOSSES		TOTAL INTERNAL ENERGY REQUIREMENTS	
	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH
ACTUAL												
1994	2,025	-	1,072	-	2,870	-	83	-	433	-	6,483	-
1995	2,192	8.2	1,135	5.9	2,980	3.8	88	6.0	413	-4.6	6,808	5.0
1996	2,191	-0.0	1,150	1.3	3,076	3.2	93	5.7	450	9.0	6,960	2.2
1997	2,197	0.3	1,166	1.4	3,142	2.1	88	-5.4	304	-32.4	6,897	-0.9
1998	2,156	-1.9	1,195	2.5	3,131	-0.4	91	3.4	419	37.8	6,992	1.4
FORECAST												
1999	2,313	7.3	1,255	5.0	3,189	1.9	91	0.0	447	6.7	7,295	4.3
2000	2,360	2.0	1,290	2.8	3,217	0.9	91	0.0	444	-0.7	7,402	1.5
2001	2,406	1.9	1,326	2.8	3,244	0.8	92	1.1	452	1.8	7,520	1.6
2002	2,451	1.9	1,362	2.7	3,271	0.8	93	1.1	450	-0.4	7,627	1.4
2003	2,495	1.8	1,398	2.6	3,298	0.8	95	2.2	454	0.9	7,740	1.5
2004	2,549	2.2	1,438	2.9	3,345	1.4	98	3.2	458	0.9	7,888	1.9
2005	2,605	2.2	1,478	2.8	3,391	1.4	101	3.1	463	1.1	8,038	1.9
2006	2,661	2.1	1,519	2.8	3,437	1.4	103	2.0	467	0.9	8,187	1.9
2007	2,717	2.1	1,559	2.6	3,483	1.3	106	2.9	471	0.9	8,336	1.8
2008	2,772	2.0	1,599	2.6	3,530	1.3	110	3.8	475	0.8	8,486	1.8
2009	2,828	2.0	1,639	2.5	3,576	1.3	112	1.8	480	1.1	8,635	1.8
2010	2,884	2.0	1,679	2.4	3,622	1.3	116	3.6	484	0.8	8,785	1.7
2011	2,939	1.9	1,720	2.4	3,669	1.3	118	1.7	488	0.8	8,934	1.7
2012	2,995	1.9	1,760	2.3	3,715	1.3	121	2.5	492	0.8	9,083	1.7
2013	3,051	1.9	1,800	2.3	3,761	1.2	124	2.5	497	1.0	9,233	1.7
2014	3,107	1.8	1,840	2.2	3,807	1.2	127	2.4	501	0.8	9,382	1.6
2015	3,164	1.8	1,880	2.2	3,854	1.2	130	2.4	505	0.8	9,533	1.6
2016	3,220	1.8	1,920	2.1	3,900	1.2	133	2.3	511	1.2	9,684	1.6
2017	3,277	1.8	1,961	2.1	3,946	1.2	135	1.5	515	0.8	9,834	1.5
2018	3,333	1.7	2,001	2.0	3,992	1.2	139	3.0	519	0.8	9,984	1.5
2019	3,388	1.7	2,041	2.0	4,039	1.2	142	2.2	523	0.8	10,133	1.5
AVERAGE ANNUAL GROWTH RATES:												
1994-1998		1.6		2.8		2.2		2.3		-0.8		1.9
1999-2019		1.9		2.5		1.2		2.2		0.8		1.7

AMERICAN ELECTRIC POWER SYSTEM
ANNUAL INTERNAL ENERGY REQUIREMENTS AND GROWTH RATES
1994-2019

REFLECTING DSM ADJUSTMENTS

	RESIDENTIAL SALES		COMMERCIAL SALES		INDUSTRIAL SALES		OTHER INTERNAL SALES		LOSSES		TOTAL INTERNAL ENERGY REQUIREMENTS	
	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH	GWH	% GROWTH
ACTUAL												
1994	28,818	-	21,209	-	43,856	-	7,702	-	7,688	-	109,273	-
1995	30,620	6.3	22,190	4.6	44,607	1.7	7,819	1.5	8,146	6.0	113,382	3.8
1996	30,854	0.8	22,558	1.7	45,676	2.4	7,993	2.2	8,867	8.9	115,948	2.3
1997	30,283	-1.9	22,720	0.7	46,584	2.0	8,061	0.9	8,488	-4.3	116,136	0.2
1998	30,414	0.4	23,599	3.9	47,298	1.5	6,618	-17.9	9,142	7.7	117,071	0.8
FORECAST												
1999	32,223	5.9	24,394	3.4	46,078	-2.6	7,081	7.0	8,928	-2.3	118,704	1.4
2000	32,876	2.0	24,958	2.3	42,226	-8.4	7,084	0.0	8,954	0.3	116,098	-2.2
2001	33,546	2.0	25,523	2.3	42,895	1.6	7,195	1.6	9,018	0.7	118,177	1.8
2002	34,209	2.0	26,087	2.2	43,553	1.5	7,309	1.6	9,070	0.6	120,228	1.7
2003	34,873	1.9	26,650	2.2	44,229	1.6	7,424	1.6	9,132	0.7	122,308	1.7
2004	35,490	1.8	27,177	2.0	44,707	1.1	7,528	1.4	9,204	0.8	124,106	1.5
2005	36,108	1.7	27,704	1.9	45,186	1.1	7,636	1.4	9,275	0.8	125,909	1.5
2006	36,725	1.7	28,231	1.9	45,664	1.1	7,751	1.5	9,348	0.8	127,719	1.4
2007	37,342	1.7	28,758	1.9	46,142	1.0	7,866	1.5	9,421	0.8	129,529	1.4
2008	37,959	1.7	29,285	1.8	46,621	1.0	7,980	1.4	9,494	0.8	131,339	1.4
2009	38,577	1.6	29,813	1.8	47,099	1.0	8,094	1.4	9,567	0.8	133,150	1.4
2010	39,194	1.6	30,340	1.8	47,578	1.0	8,209	1.4	9,640	0.8	134,961	1.4
2011	39,811	1.6	30,867	1.7	48,056	1.0	8,324	1.4	9,713	0.8	136,771	1.3
2012	40,429	1.6	31,394	1.7	48,535	1.0	8,437	1.4	9,786	0.8	138,581	1.3
2013	41,046	1.5	31,921	1.7	49,013	1.0	8,555	1.4	9,858	0.7	140,393	1.3
2014	41,663	1.5	32,448	1.7	49,491	1.0	8,671	1.4	9,931	0.7	142,204	1.3
2015	42,280	1.5	32,975	1.6	49,970	1.0	8,795	1.4	10,006	0.8	144,026	1.3
2016	42,898	1.5	33,503	1.6	50,448	1.0	8,917	1.4	10,080	0.7	145,846	1.3
2017	43,515	1.4	34,030	1.6	50,927	0.9	9,042	1.4	10,154	0.7	147,668	1.2
2018	44,132	1.4	34,557	1.5	51,405	0.9	9,157	1.3	10,227	0.7	149,478	1.2
2019	44,749	1.4	35,084	1.5	51,884	0.9	9,271	1.2	10,300	0.7	151,288	1.2
AVERAGE ANNUAL GROWTH RATES:												
1994-1998		1.4		2.7		1.9		-3.7		4.4		1.7
1999-2019		1.7		1.8		0.6		1.4		0.7		1.2

KENTUCKY POWER COMPANY
SEASONAL AND ANNUAL PEAK DEMANDS, ENERGY REQUIREMENTS AND LOAD FACTOR
1994-2019

REFLECTING DSM ADJUSTMENTS

	SUMMER PEAK			WINTER PEAK (1)			ANNUAL PEAK, ENERGY AND LOAD FACTOR				
	DATE	MW	% GROWTH	DATE	MW	% GROWTH	MW	% GROWTH	GWH	% GROWTH	LOAD FACTOR (%)
ACTUAL											
1994	06/20/94	1,079	-	02/09/95	1,363	-	1,309	-	6,483	-	56.5
1995	08/15/95	1,136	5.3	02/05/96	1,418	4.0	1,363	4.1	6,808	5.0	57.0
1996	08/07/96	1,087	-4.3	01/17/97	1,417	-0.1	1,418	4.0	6,960	2.2	56.0
1997	07/28/97	1,164	7.1	03/13/98	1,299	-8.3	1,417	-0.1	6,897	-0.9	55.6
1998	08/25/98	1,213	4.2	01/05/99	1,432	10.2	1,299	-8.3	6,992	1.4	61.4
FORECAST											
1999		1,231	1.5		1,460	2.0	1,460	12.4	7,295	4.3	57.0
2000		1,249	1.5		1,486	1.8	1,486	1.8	7,402	1.5	56.9
2001		1,269	1.6		1,509	1.5	1,509	1.5	7,520	1.6	56.9
2002		1,290	1.7		1,533	1.6	1,533	1.6	7,627	1.4	56.8
2003		1,311	1.6		1,566	2.2	1,566	2.2	7,740	1.5	56.4
2004		1,335	1.8		1,597	2.0	1,597	2.0	7,888	1.9	56.4
2005		1,359	1.8		1,630	2.1	1,630	2.1	8,038	1.9	56.3
2006		1,383	1.8		1,662	2.0	1,662	2.0	8,187	1.9	56.2
2007		1,408	1.8		1,694	1.9	1,694	1.9	8,336	1.8	56.2
2008		1,432	1.7		1,727	1.9	1,727	1.9	8,486	1.8	56.1
2009		1,457	1.7		1,759	1.9	1,759	1.9	8,635	1.8	56.0
2010		1,482	1.7		1,791	1.8	1,791	1.8	8,785	1.7	56.0
2011		1,506	1.6		1,824	1.8	1,824	1.8	8,934	1.7	55.9
2012		1,531	1.7		1,856	1.8	1,856	1.8	9,083	1.7	55.9
2013		1,555	1.6		1,889	1.8	1,889	1.8	9,233	1.7	55.8
2014		1,581	1.7		1,923	1.8	1,923	1.8	9,382	1.6	55.7
2015		1,606	1.6		1,955	1.7	1,955	1.7	9,533	1.6	55.7
2016		1,630	1.5		1,989	1.7	1,989	1.7	9,684	1.6	55.6
2017		1,655	1.5		2,021	1.6	2,021	1.6	9,834	1.5	55.5
2018		1,679	1.5		2,054	1.6	2,054	1.6	9,984	1.5	55.5
2019		1,704	1.5		2,088	1.7	2,088	1.7	10,133	1.5	55.4
AVERAGE ANNUAL GROWTH RATES:											
1994-1998			3.0			1.2		-0.2		1.9	
1999-2019			1.6			1.8		1.8		1.7	

Note : (1) Actual winter peak for year may occur in the 4th quarter of that year or in the 1st quarter of the following year.

AMERICAN ELECTRIC POWER SYSTEM
SEASONAL AND ANNUAL PEAK DEMANDS, ENERGY REQUIREMENTS AND LOAD FACTOR
1994-2019

REFLECTING DSM ADJUSTMENTS

	SUMMER PEAK			WINTER PEAK (1)			ANNUAL PEAK, ENERGY AND LOAD FACTOR				
	DATE	MW	% GROWTH	DATE	MW	% GROWTH	MW	% GROWTH	GWH	% GROWTH	LOAD FACTOR (%)
ACTUAL											
1994	06/20/94	18,070	-	02/09/95	18,633	-	19,236	-	109,273	-	64.8
1995	08/14/95	19,516	8.0	02/05/96	19,557	5.0	19,516	1.5	113,382	3.8	66.3
1996	08/07/96	18,864	-3.3	01/17/97	19,381	-0.9	19,557	0.2	115,948	2.3	67.7
1997	07/14/97	19,119	1.4	03/13/98	17,841	-7.9	19,381	-0.9	116,136	0.2	68.4
1998	07/21/98	19,414	1.5	01/05/99	18,546	4.0	19,414	0.2	117,071	0.8	68.8
FORECAST											
1999		19,793	2.0		19,071	2.8	19,793	2.0	118,704	1.4	68.5
2000		19,722	-0.4		19,351	1.5	19,722	-0.4	116,098	-2.2	67.2
2001		20,052	1.7		19,630	1.4	20,052	1.7	118,177	1.8	67.3
2002		20,396	1.7		19,915	1.5	20,396	1.7	120,228	1.7	67.3
2003		20,743	1.7		20,194	1.4	20,743	1.7	122,308	1.7	67.3
2004		21,071	1.6		20,472	1.4	21,071	1.6	124,106	1.5	67.2
2005		21,401	1.6		20,760	1.4	21,401	1.6	125,909	1.5	67.2
2006		21,732	1.5		21,049	1.4	21,732	1.5	127,719	1.4	67.1
2007		22,062	1.5		21,338	1.4	22,062	1.5	129,529	1.4	67.0
2008		22,393	1.5		21,627	1.4	22,393	1.5	131,339	1.4	67.0
2009		22,724	1.5		21,916	1.3	22,724	1.5	133,150	1.4	66.9
2010		23,055	1.5		22,205	1.3	23,055	1.5	134,961	1.4	66.8
2011		23,385	1.4		22,493	1.3	23,385	1.4	136,771	1.3	66.8
2012		23,716	1.4		22,782	1.3	23,716	1.4	138,581	1.3	66.7
2013		24,047	1.4		23,071	1.3	24,047	1.4	140,393	1.3	66.6
2014		24,379	1.4		23,370	1.3	24,379	1.4	142,204	1.3	66.6
2015		24,713	1.4		23,668	1.3	24,713	1.4	144,026	1.3	66.5
2016		25,047	1.4		23,967	1.3	25,047	1.4	145,846	1.3	66.5
2017		25,380	1.3		24,255	1.2	25,380	1.3	147,668	1.2	66.4
2018		25,710	1.3		24,544	1.2	25,710	1.3	149,478	1.2	66.4
2019		26,041	1.3		24,843	1.2	26,041	1.3	151,288	1.2	66.3
AVERAGE ANNUAL GROWTH RATES:											
1994-1998			1.8			-0.1		0.2		1.7	
1999-2019			1.4			1.3		1.4		1.2	

Note : (1) Actual winter peak for year may occur in the 4th quarter of that year or in the 1st quarter of the following year.

KENTUCKY POWER COMPANY
ANNUAL INTERNAL LOAD
1999-2009

REFLECTING DSM ADJUSTMENTS

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
INTERNAL ENERGY (GWH)											
RESIDENTIAL	2,313	2,360	2,406	2,451	2,495	2,549	2,605	2,661	2,717	2,772	2,828
COMMERCIAL	1,255	1,290	1,326	1,362	1,398	1,438	1,478	1,519	1,559	1,599	1,639
OTHER INDUSTRIAL	2,051	2,068	2,086	2,102	2,120	2,149	2,178	2,207	2,236	2,266	2,295
NONASSOC. MINE POWER	1,137	1,149	1,159	1,169	1,179	1,196	1,213	1,230	1,247	1,264	1,281
TOTAL INDUSTRIAL	3,189	3,217	3,244	3,271	3,298	3,345	3,391	3,437	3,483	3,530	3,576
STREET LIGHTING	11	11	11	11	11	11	11	12	12	12	12
TOTAL OTHER ULTIMATE	11	11	11	11	11	11	11	12	12	12	12
TOTAL ULTIMATE SALES	6,767	6,877	6,987	7,095	7,202	7,344	7,486	7,628	7,770	7,913	8,055
MUNICIPALS	80	81	82	83	83	86	89	92	95	98	100
TOTAL SALES FOR RESALE	80	81	82	83	83	86	89	92	95	98	100
TOTAL INTERNAL SALES	6,847	6,958	7,068	7,177	7,286	7,430	7,575	7,720	7,865	8,010	8,155
TOTAL LOSSES	447	444	452	450	454	458	463	467	471	475	480
TOTAL INTERNAL ENERGY	7,295	7,402	7,520	7,627	7,740	7,888	8,038	8,187	8,336	8,486	8,635
INTERNAL PEAK DEMAND (MW)											
SUMMER	1,231	1,249	1,269	1,290	1,311	1,335	1,359	1,383	1,408	1,432	1,457
PRECEDING WINTER	1,442	1,460	1,486	1,509	1,533	1,566	1,597	1,630	1,662	1,694	1,727

KENTUCKY POWER COMPANY
ANNUAL INTERNAL LOAD
2010-2019

REFLECTING DSM ADJUSTMENTS

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
INTERNAL ENERGY (GWH)										
RESIDENTIAL	2,884	2,939	2,995	3,051	3,107	3,164	3,220	3,277	3,333	3,388
COMMERCIAL	1,679	1,720	1,760	1,800	1,840	1,880	1,920	1,961	2,001	2,041
OTHER INDUSTRIAL	2,324	2,353	2,382	2,411	2,441	2,470	2,499	2,528	2,557	2,587
NONASSOC. MINE POWER	1,298	1,315	1,333	1,350	1,367	1,384	1,401	1,418	1,435	1,452
TOTAL INDUSTRIAL	3,622	3,669	3,715	3,761	3,807	3,854	3,900	3,946	3,992	4,039
STREET LIGHTING	12	12	12	12	12	13	13	13	13	13
TOTAL OTHER ULTIMATE	12	12	12	12	12	13	13	13	13	13
TOTAL ULTIMATE SALES	8,197	8,340	8,482	8,624	8,767	8,911	9,053	9,196	9,339	9,481
MUNICIPALS	103	106	109	112	115	117	120	123	126	129
TOTAL SALES FOR RESALE	103	106	109	112	115	117	120	123	126	129
TOTAL INTERNAL SALES	8,301	8,446	8,591	8,736	8,881	9,028	9,173	9,319	9,465	9,610
TOTAL LOSSES	484	488	492	497	501	505	511	515	519	523
TOTAL INTERNAL ENERGY	8,785	8,934	9,083	9,233	9,382	9,533	9,684	9,834	9,984	10,133
INTERNAL PEAK DEMAND (MW)										
SUMMER	1,482	1,506	1,531	1,555	1,581	1,606	1,630	1,655	1,679	1,704
PRECEDING WINTER	1,759	1,791	1,824	1,856	1,889	1,923	1,955	1,989	2,021	2,054

Exhibit 2-18

KENTUCKY POWER COMPANY
MONTHLY INTERNAL LOAD
1999

REFLECTING DSM ADJUSTMENTS

INTERNAL ENERGY (GWH)	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
RESIDENTIAL	275.5	223.7	196.1	155.1	143.0	161.1	202.7	195.5	156.1	154.1	198.9	250.8	2,313
COMMERCIAL	119.5	104.3	101.7	91.6	100.2	102.4	112.2	109.6	102.0	99.3	100.5	111.8	1,255
OTHER INDUSTRIAL	172.2	160.5	167.4	169.8	175.5	170.2	172.2	174.2	169.4	175.6	169.2	175.2	2,051
NONASSOC. MINE POWER	102.9	103.2	104.9	92.3	90.0	86.0	76.7	91.8	83.9	99.6	100.5	105.7	1,138
TOTAL INDUSTRIAL	275.1	263.7	272.3	262.1	265.5	256.2	248.9	266.0	253.3	275.2	269.7	280.9	3,189
STREET LIGHTING	1.1	0.9	0.9	0.8	0.8	0.7	0.8	0.8	0.8	1.0	1.0	1.1	11
TOTAL OTHER ULTIMATE	1.1	0.9	0.9	0.8	0.8	0.7	0.8	0.8	0.8	1.0	1.0	1.1	11
TOTAL ULTIMATE SALES	671.2	592.6	571.0	509.6	509.5	520.4	564.6	571.9	512.2	529.6	570.1	644.6	6,767
MUNICIPALS	8.3	7.2	7.0	5.2	6.2	6.2	6.5	7.9	5.7	5.7	6.6	7.7	80
TOTAL SALES FOR RESALE	8.3	7.2	7.0	5.2	6.2	6.2	6.5	7.9	5.7	5.7	6.6	7.7	80
TOTAL INTERNAL SALES	679.5	599.8	578.0	514.8	515.7	526.6	571.1	579.8	517.9	535.3	576.7	652.3	6,848
TOTAL LOSSES	43.7	39.6	38.4	33.4	31.0	31.8	37.7	36.3	35.1	37.0	39.0	44.4	447
TOTAL INTERNAL ENERGY	723.2	639.4	616.4	548.2	546.7	558.4	608.8	616.1	553.0	572.3	615.7	696.7	7,295
INTERNAL PEAK DEMAND (MW)	1444	1326	1209	1088	1004	1147	1213	1231	1121	1055	1209	1331	1,444

KENTUCKY POWER COMPANY
MONTHLY INTERNAL LOAD
2000

REFLECTING DSM ADJUSTMENTS

INTERNAL ENERGY (GWH)	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
RESIDENTIAL	276.3	228.2	204.0	162.2	151.0	163.5	204.9	197.9	159.2	157.4	202.5	252.9	2,360
COMMERCIAL	121.8	106.9	104.8	94.5	102.9	105.6	115.2	112.4	105.2	102.3	103.3	114.8	1,290
OTHER INDUSTRIAL	173.3	161.6	168.6	171.2	176.9	171.7	173.7	175.7	170.9	177.2	170.8	176.8	2,068
NONASSOC. MINE POWER	105.0	103.2	105.9	93.2	91.3	86.7	77.6	92.9	84.5	100.5	101.3	106.7	1,149
TOTAL INDUSTRIAL	278.3	264.8	274.5	264.4	268.2	258.4	251.3	268.6	255.4	277.7	272.1	283.5	3,217
STREET LIGHTING	1.1	0.9	0.9	0.8	0.8	0.7	0.8	0.8	0.9	1.0	1.0	1.1	11
TOTAL OTHER ULTIMATE	1.1	0.9	0.9	0.8	0.8	0.7	0.8	0.8	0.9	1.0	1.0	1.1	11
TOTAL ULTIMATE SALES	677.5	600.8	584.2	521.9	522.9	528.2	572.2	579.7	520.7	538.4	578.9	652.3	6,878
MUNICIPALS	8.2	7.3	7.1	4.9	6.3	6.5	6.3	8.0	6.0	5.7	6.6	7.9	81
TOTAL SALES FOR RESALE	8.2	7.3	7.1	4.9	6.3	6.5	6.3	8.0	6.0	5.7	6.6	7.9	81
TOTAL INTERNAL SALES	685.7	608.1	591.3	526.8	529.2	534.7	578.5	587.7	526.7	544.1	585.5	660.2	6,959
TOTAL LOSSES	41.6	36.8	37.0	32.1	30.1	33.0	37.8	36.6	36.1	37.5	39.7	45.8	444
TOTAL INTERNAL ENERGY	727.3	644.9	628.3	558.9	559.3	567.7	616.3	624.3	562.8	581.6	625.2	706.0	7,403
INTERNAL PEAK DEMAND (MW)	1460	1344	1235	1109	1027	1168	1231	1249	1141	1071	1229	1353	1,460

AMERICAN ELECTRIC POWER SYSTEM
LOW, BASE AND HIGH CASE FOR
FORECASTED SEASONAL PEAK DEMANDS AND INTERNAL ENERGY REQUIREMENTS
1999-2019

BEFORE DSM ADJUSTMENTS

YEAR	SUMMER PEAK INTERNAL DEMANDS (MW) LOW CASE	BASE CASE	HIGH CASE	WINTER (FOLLOWING) PEAK INTERNAL DEMANDS (MW) LOW CASE	BASE CASE	HIGH CASE	INTERNAL ENERGY REQUIREMENTS (GWH) LOW CASE	BASE CASE	HIGH CASE
1999	19,485	19,795	20,107	18,691	19,082	19,474	116,855	118,710	120,578
2000	19,324	19,727	20,132	18,895	19,372	19,849	113,745	116,116	118,496
2001	19,566	20,060	20,553	19,095	19,660	20,219	115,299	118,205	121,109
2002	19,822	20,407	20,986	19,305	19,955	20,595	116,822	120,268	123,679
2003	20,082	20,757	21,422	19,511	20,244	20,969	118,381	122,358	126,273
2004	20,326	21,088	21,842	19,714	20,533	21,340	119,683	124,168	128,603
2005	20,566	21,419	22,260	19,915	20,821	21,716	120,965	125,978	130,920
2006	20,805	21,750	22,684	20,113	21,110	22,094	122,237	127,788	133,270
2007	21,038	22,080	23,108	20,308	21,399	22,476	123,486	129,598	135,627
2008	21,270	22,411	23,538	20,497	21,687	22,859	124,722	131,408	138,010
2009	21,496	22,742	23,969	20,689	21,976	23,244	125,927	133,219	140,401
2010	21,724	23,073	24,403	20,874	22,265	23,634	127,139	135,029	142,806
2011	21,943	23,403	24,840	21,057	22,553	24,026	128,309	136,839	145,236
2012	22,162	23,734	25,282	21,239	22,842	24,419	129,473	138,649	147,684
2013	22,378	24,065	25,725	21,419	23,131	24,812	130,622	140,459	150,140
2014	22,591	24,395	26,166	21,596	23,419	25,205	131,758	142,269	152,589
2015	22,804	24,726	26,609	21,771	23,708	25,605	132,887	144,079	155,045
2016	23,012	25,057	27,059	21,943	23,997	26,010	133,990	145,889	157,539
2017	23,219	25,388	27,519	22,119	24,285	26,426	135,062	147,700	160,060
2018	23,428	25,718	27,987	22,295	24,574	26,849	136,142	149,510	162,621
2019	23,639	26,049	28,463	22,474	24,873	27,279	137,232	151,320	165,222
AVERAGE ANNUAL GROWTH RATES % 1999-2019	1.0	1.4	1.8	0.9	1.3	1.7	0.8	1.2	1.6

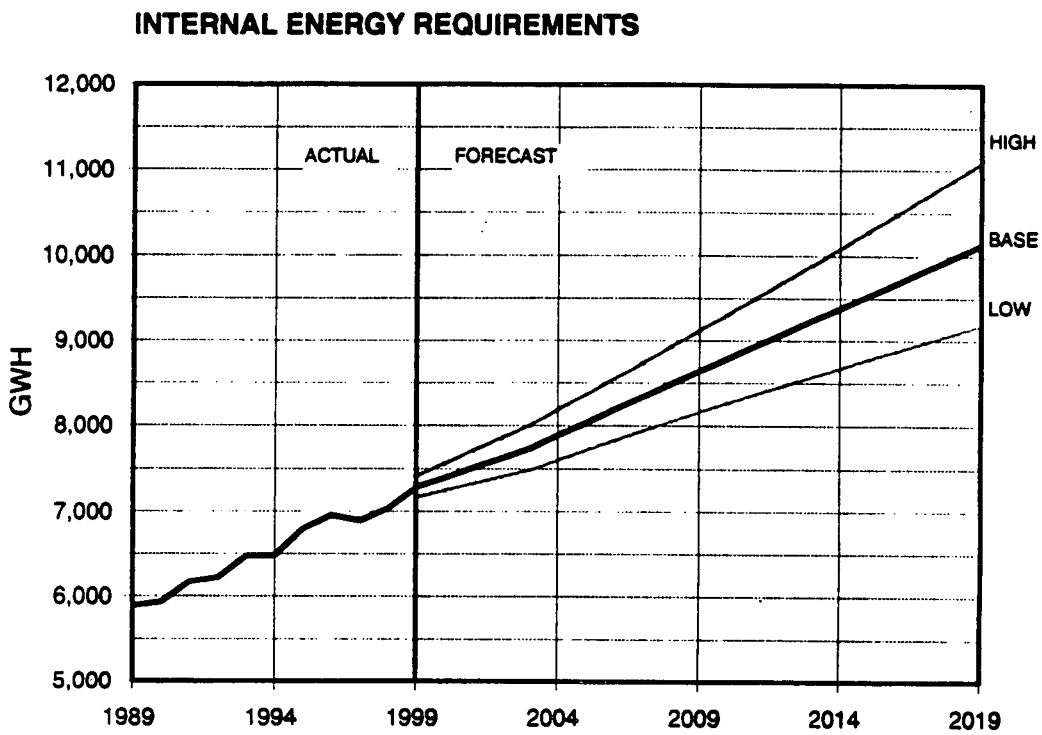
KENTUCKY POWER COMPANY
LOW, BASE AND HIGH CASE FOR
FORECASTED SEASONAL PEAK DEMANDS AND INTERNAL ENERGY REQUIREMENTS
1999-2019

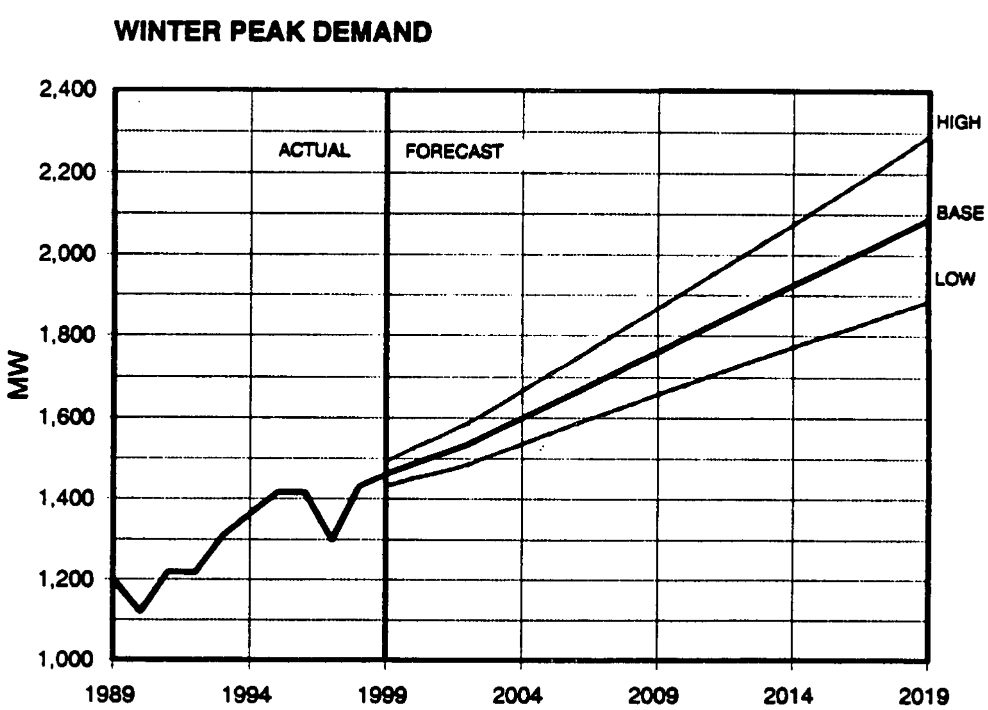
BEFORE DSM ADJUSTMENTS

	SUMMER PEAK INTERNAL DEMANDS (MW)			WINTER (FOLLOWING) PEAK INTERNAL DEMANDS (MW)			INTERNAL ENERGY REQUIREMENTS (GWH)		
YEAR	LOW CASE	BASE CASE	HIGH CASE	LOW CASE	BASE CASE	HIGH CASE	LOW CASE	BASE CASE	HIGH CASE
1999	1,210	1,231	1,252	1,431	1,462	1,493	7,175	7,297	7,419
2000	1,224	1,250	1,276	1,451	1,488	1,526	7,250	7,406	7,562
2001	1,238	1,270	1,302	1,468	1,512	1,556	7,334	7,524	7,713
2002	1,253	1,291	1,329	1,486	1,537	1,587	7,407	7,632	7,854
2003	1,268	1,312	1,355	1,512	1,570	1,627	7,488	7,746	8,000
2004	1,287	1,336	1,385	1,537	1,602	1,666	7,603	7,895	8,184
2005	1,306	1,361	1,416	1,562	1,635	1,707	7,716	8,045	8,368
2006	1,323	1,385	1,446	1,587	1,667	1,746	7,830	8,194	8,554
2007	1,342	1,410	1,477	1,611	1,699	1,786	7,941	8,343	8,741
2008	1,359	1,434	1,508	1,635	1,732	1,828	8,051	8,493	8,929
2009	1,377	1,459	1,539	1,659	1,764	1,868	8,158	8,642	9,118
2010	1,395	1,484	1,571	1,682	1,796	1,909	8,266	8,792	9,309
2011	1,412	1,508	1,603	1,705	1,829	1,951	8,371	8,941	9,502
2012	1,429	1,533	1,635	1,728	1,861	1,992	8,475	9,090	9,696
2013	1,446	1,557	1,667	1,751	1,894	2,034	8,578	9,240	9,890
2014	1,463	1,582	1,699	1,773	1,926	2,076	8,680	9,389	10,085
2015	1,479	1,607	1,732	1,795	1,958	2,118	8,782	9,538	10,280
2016	1,495	1,631	1,764	1,817	1,991	2,161	8,881	9,688	10,478
2017	1,512	1,656	1,797	1,840	2,023	2,204	8,981	9,837	10,677
2018	1,529	1,680	1,830	1,863	2,056	2,248	9,083	9,987	10,880
2019	1,547	1,705	1,864	1,886	2,090	2,293	9,186	10,136	11,087
AVERAGE ANNUAL GROWTH RATES % 1999-2019	1.2	1.6	2.0	1.4	1.8	2.2	1.2	1.7	2.0

Exhibit 2-22

KENTUCKY POWER COMPANY
RANGE OF FORECASTS





AMERICAN ELECTRIC POWER SYSTEM
LOW, BASE AND HIGH CASE FOR
FORECASTED SEASONAL PEAK DEMANDS AND INTERNAL ENERGY REQUIREMENTS
1999-2019

REFLECTING DSM ADJUSTMENTS

	SUMMER PEAK INTERNAL DEMANDS (MW)			WINTER (FOLLOWING) PEAK INTERNAL DEMANDS (MW)			INTERNAL ENERGY REQUIREMENTS (GWH)		
YEAR	LOW CASE	BASE CASE	HIGH CASE	LOW CASE	BASE CASE	HIGH CASE	LOW CASE	BASE CASE	HIGH CASE
1999	19,483	19,793	20,105	18,680	19,071	19,463	116,849	118,704	120,572
2000	19,319	19,722	20,127	18,874	19,351	19,828	113,727	116,098	118,478
2001	19,558	20,052	20,545	19,065	19,630	20,189	115,271	118,177	121,081
2002	19,811	20,396	20,975	19,265	19,915	20,555	116,782	120,228	123,639
2003	20,068	20,743	21,408	19,461	20,194	20,919	118,331	122,308	126,223
2004	20,309	21,071	21,825	19,653	20,472	21,279	119,621	124,106	128,541
2005	20,548	21,401	22,242	19,854	20,760	21,655	120,896	125,909	130,851
2006	20,787	21,732	22,666	20,052	21,049	22,033	122,168	127,719	133,201
2007	21,020	22,062	23,090	20,247	21,338	22,415	123,417	129,529	135,558
2008	21,252	22,393	23,520	20,437	21,627	22,799	124,653	131,339	137,941
2009	21,478	22,724	23,951	20,629	21,916	23,184	125,858	133,150	140,332
2010	21,706	23,055	24,385	20,814	22,205	23,574	127,071	134,961	142,738
2011	21,925	23,385	24,822	20,997	22,493	23,966	128,241	136,771	145,168
2012	22,144	23,716	25,264	21,179	22,782	24,359	129,405	138,581	147,616
2013	22,360	24,047	25,707	21,359	23,071	24,752	130,556	140,393	150,074
2014	22,575	24,379	26,150	21,547	23,370	25,156	131,693	142,204	152,524
2015	22,791	24,713	26,596	21,731	23,668	25,565	132,834	144,026	154,992
2016	23,002	25,047	27,049	21,913	23,967	25,980	133,947	145,846	157,496
2017	23,211	25,380	27,511	22,089	24,255	26,396	135,030	147,668	160,028
2018	23,420	25,710	27,979	22,265	24,544	26,819	136,110	149,478	162,589
2019	23,631	26,041	28,455	22,444	24,843	27,249	137,200	151,288	165,190
AVERAGE ANNUAL GROWTH RATES % 1999-2019	1.0	1.4	1.8	0.9	1.3	1.7	0.8	1.2	1.6

KENTUCKY POWER COMPANY
LOW, BASE AND HIGH CASE FOR
FORECASTED SEASONAL PEAK DEMANDS AND INTERNAL ENERGY REQUIREMENTS
1999-2019

REFLECTING DSM ADJUSTMENTS

	SUMMER PEAK INTERNAL DEMANDS (MW)			WINTER (FOLLOWING) PEAK INTERNAL DEMANDS (MW)			INTERNAL ENERGY REQUIREMENTS (GWH)		
YEAR	LOW CASE	BASE CASE	HIGH CASE	LOW CASE	BASE CASE	HIGH CASE	LOW CASE	BASE CASE	HIGH CASE
1999	1,210	1,231	1,252	1,429	1,460	1,491	7,173	7,295	7,417
2000	1,223	1,249	1,275	1,449	1,486	1,524	7,246	7,402	7,558
2001	1,237	1,269	1,301	1,465	1,509	1,553	7,330	7,520	7,709
2002	1,252	1,290	1,328	1,482	1,533	1,583	7,402	7,627	7,849
2003	1,267	1,311	1,354	1,508	1,566	1,623	7,482	7,740	7,994
2004	1,286	1,335	1,384	1,532	1,597	1,661	7,596	7,888	8,177
2005	1,304	1,359	1,414	1,557	1,630	1,702	7,709	8,038	8,361
2006	1,321	1,383	1,444	1,582	1,662	1,741	7,823	8,187	8,547
2007	1,340	1,408	1,475	1,606	1,694	1,781	7,934	8,336	8,734
2008	1,357	1,432	1,506	1,630	1,727	1,823	8,044	8,486	8,922
2009	1,375	1,457	1,537	1,654	1,759	1,863	8,151	8,635	9,111
2010	1,393	1,482	1,569	1,677	1,791	1,904	8,259	8,785	9,302
2011	1,410	1,506	1,601	1,700	1,824	1,946	8,364	8,934	9,495
2012	1,427	1,531	1,633	1,723	1,856	1,987	8,468	9,083	9,689
2013	1,444	1,555	1,665	1,746	1,889	2,029	8,571	9,233	9,883
2014	1,462	1,581	1,698	1,770	1,923	2,073	8,673	9,382	10,078
2015	1,478	1,606	1,731	1,792	1,955	2,115	8,777	9,533	10,275
2016	1,494	1,630	1,763	1,815	1,989	2,159	8,877	9,684	10,474
2017	1,511	1,655	1,796	1,838	2,021	2,202	8,978	9,834	10,674
2018	1,528	1,679	1,829	1,861	2,054	2,246	9,080	9,984	10,877
2019	1,546	1,704	1,863	1,884	2,088	2,291	9,183	10,133	11,084
AVERAGE ANNUAL GROWTH RATES % 1999-2019	1.2	1.6	2.0	1.4	1.8	2.2	1.2	1.7	2.0

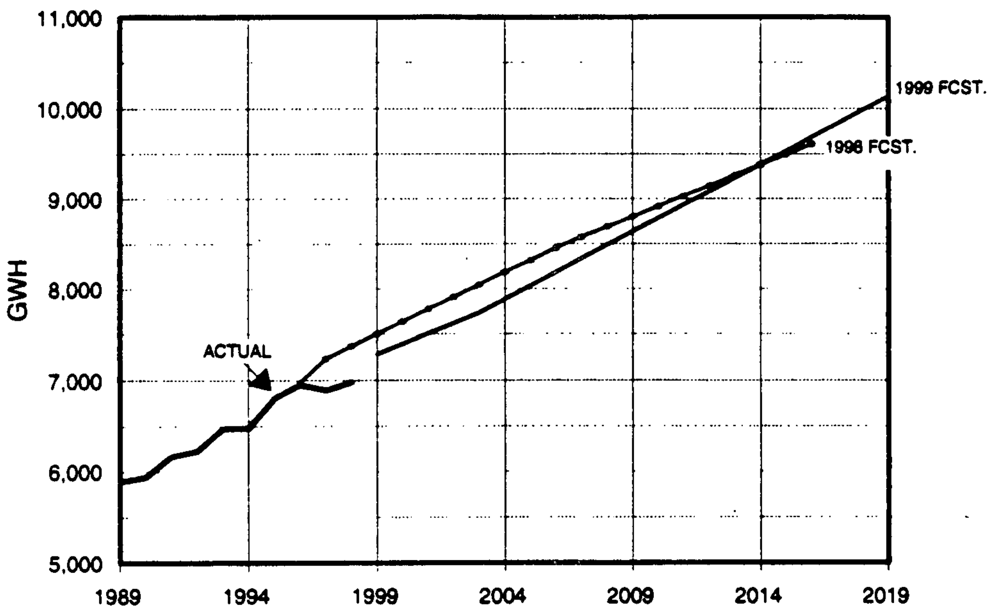
KENTUCKY POWER COMPANY AND AEP SYSTEM
TOTAL INTERNAL ENERGY REQUIREMENTS
COMPARISON OF 1996 AND 1999 FORECASTS

BEFORE DSM ADJUSTMENTS

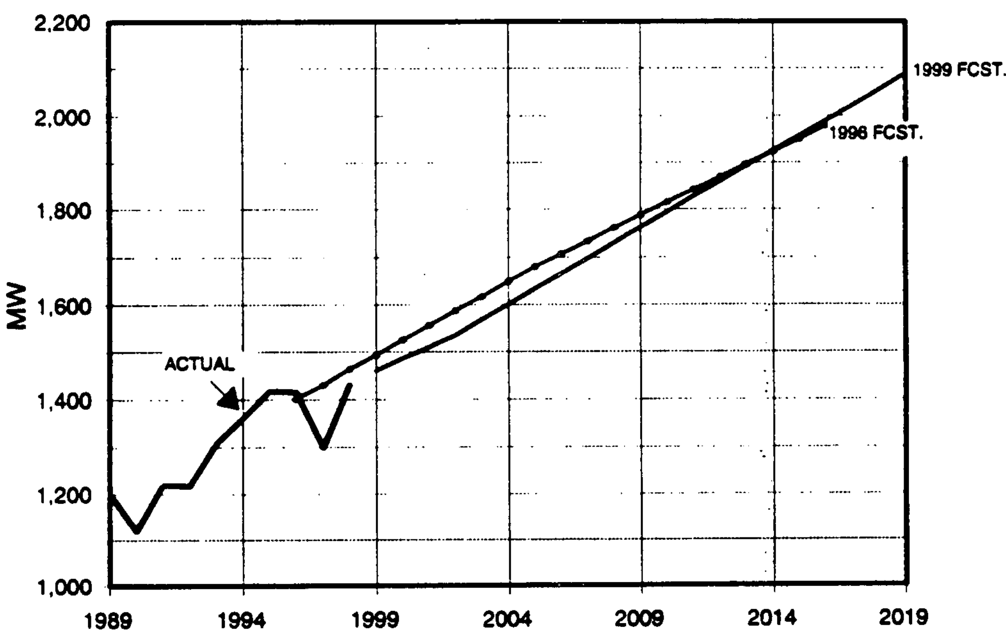
	KPCO				AEP			
Forecast Year	1999 Forecast GWH	1996 Forecast GWH	Change From 1996 Forecast GWH	Change From 1996 Forecast Percent	1999 Forecast GWH	1996 Forecast GWH	Change From 1996 Forecast GWH	Change From 1996 Forecast Percent
1996	-	6,976	-	-	-	115,293	-	-
1997	-	7,239	-	-	-	118,117	-	-
1998	-	7,372	-	-	-	119,007	-	-
1999	7,297	7,510	-213	-2.8	118,710	119,457	-747	-0.6
2000	7,406	7,644	-238	-3.1	116,116	121,285	-5,169	-4.3
2001	7,524	7,782	-258	-3.3	118,205	123,194	-4,989	-4.0
2002	7,632	7,916	-284	-3.6	120,268	125,091	-4,823	-3.9
2003	7,746	8,052	-306	-3.8	122,358	126,994	-4,636	-3.7
2004	7,895	8,187	-292	-3.6	124,168	128,896	-4,728	-3.7
2005	8,045	8,323	-278	-3.3	125,978	130,792	-4,814	-3.7
2006	8,194	8,459	-265	-3.1	127,788	132,702	-4,914	-3.7
2007	8,343	8,575	-232	-2.7	129,598	134,312	-4,714	-3.5
2008	8,493	8,691	-198	-2.3	131,408	135,907	-4,499	-3.3
2009	8,642	8,806	-164	-1.9	133,219	137,515	-4,296	-3.1
2010	8,792	8,921	-129	-1.4	135,029	139,115	-4,086	-2.9
2011	8,941	9,038	-97	-1.1	136,839	140,716	-3,877	-2.8
2012	9,090	9,152	-62	-0.7	138,649	142,322	-3,673	-2.6
2013	9,240	9,268	-28	-0.3	140,459	143,926	-3,467	-2.4
2014	9,389	9,384	5	0.1	142,269	145,532	-3,263	-2.2
2015	9,538	9,499	39	0.4	144,079	147,129	-3,050	-2.1
2016	9,688	9,617	71	0.7	145,889	148,742	-2,853	-1.9
2017	9,837	-	-	-	147,700	-	-	-
2018	9,987	-	-	-	149,510	-	-	-
2019	10,136	-	-	-	151,320	-	-	-
Growth Rate (%)	1.7	1.6			1.2	1.3		

KENTUCKY POWER COMPANY
COMPARISON OF FORECASTS

INTERNAL ENERGY REQUIREMENTS



WINTER PEAK DEMAND



KENTUCKY POWER COMPANY AND AEP SYSTEM
WINTER PEAK INTERNAL DEMANDS
COMPARISON OF 1996 AND 1999 FORECASTS

BEFORE DSM ADJUSTMENTS

	KPCO				AEP			
Winter Season	1999 Forecast MW	1996 Forecast MW	Change From 1996 Forecast MW	Change From 1996 Forecast Percent	1999 Forecast MW	1996 Forecast MW	Change From 1996 Forecast MW	Change From 1996 Forecast Percent
1996	-	1,401	-	-	-	19,454	-	-
1997	-	1,431	-	-	-	19,737	-	-
1998	-	1,464	-	-	-	19,668	-	-
1999	1,462	1,494	-32	-2.1	19,082	19,950	-868	-4.4
2000	1,488	1,526	-38	-2.5	19,372	20,263	-891	-4.4
2001	1,512	1,557	-45	-2.9	19,660	20,572	-912	-4.4
2002	1,537	1,588	-51	-3.2	19,955	20,883	-928	-4.4
2003	1,570	1,618	-48	-3.0	20,244	21,192	-948	-4.5
2004	1,602	1,649	-47	-2.9	20,533	21,502	-969	-4.5
2005	1,635	1,680	-45	-2.7	20,821	21,811	-990	-4.5
2006	1,667	1,707	-40	-2.3	21,110	22,016	-906	-4.1
2007	1,699	1,734	-35	-2.0	21,399	22,219	-820	-3.7
2008	1,732	1,762	-30	-1.7	21,687	22,424	-737	-3.3
2009	1,764	1,789	-25	-1.4	21,976	22,628	-652	-2.9
2010	1,796	1,816	-20	-1.1	22,265	22,832	-567	-2.5
2011	1,829	1,843	-14	-0.8	22,553	23,036	-483	-2.1
2012	1,861	1,870	-9	-0.5	22,842	23,239	-397	-1.7
2013	1,894	1,897	-3	-0.2	23,131	23,444	-313	-1.3
2014	1,926	1,924	2	0.1	23,419	23,648	-229	-1.0
2015	1,958	1,951	7	0.4	23,708	23,851	-143	-0.6
2016	1,991	1,979	12	0.6	23,997	24,060	-63	-0.3
2017	2,023	-	-	-	24,285	-	-	-
2018	2,056	-	-	-	24,574	-	-	-
2019	2,090	-	-	-	24,873	-	-	-
Growth Rate (%)	1.8	1.7			1.3	1.1		

KENTUCKY POWER COMPANY
AVERAGE ANNUAL NUMBER OF CUSTOMERS BY CLASS
1994-1998

	1994	1995	1996	1997	1998
A. Residential					
1. Heating Customers	63,296	66,369	67,861	71,038	73,288
2. Nonheating Customers	75,343	74,041	72,983	71,160	69,310
3. Total	138,639	140,410	140,844	142,198	142,598
B. Commercial	22,402	22,796	23,048	23,691	24,213
C. Industrial					
1. Manufacturing	1,081	1,063	1,068	1,077	1,065
2. Mine Power	703	649	643	613	589
3. Total	1,784	1,712	1,711	1,690	1,654
D. Other Ultimate Sales					
1. Street Lighting	461	466	467	476	499
2. Other	0	0	0	0	0
3. Total	461	466	467	476	499
E. Total Ultimate Sales	163,286	165,384	166,070	168,055	168,964
F. Internal Sales for Resale					
1. Municipals	2	2	2	2	2
2. Other	0	0	0	0	0
3. Total	2	2	2	2	2
G. Total Internal Sales	163,288	165,386	166,072	168,057	168,966

KENTUCKY POWER COMPANY
ANNUAL INTERNAL LOAD BY CLASS (GWH)
1994-1998

	1994	1995	1996	1997	1998
A. Residential					
1. Heating Customers	1,207	1,335	1,376	1,399	1,361
2. Nonheating Customers	818	857	815	797	795
3. Total	2,025	2,192	2,191	2,196	2,156
B. Commercial	1,072	1,135	1,150	1,166	1,195
C. Industrial					
1. Manufacturing	1,764	1,906	1,978	2,031	2,021
2. Mine Power	1,106	1,074	1,098	1,111	1,110
3. Total	2,870	2,980	3,076	3,142	3,131
D. Other Ultimate Sales					
1. Street Lighting	10	10	10	10	11
2. Total	10	10	10	10	11
E. Total Ultimate Sales	5,977	6,317	6,427	6,514	6,493
F. Internal Sales for Resale					
1. Municipals	73	78	83	79	81
2. Others	0	0	0	0	0
3. Total	73	78	83	79	81
G. Total Internal Sales	6,050	6,395	6,510	6,593	6,574
H. Losses	433	413	450	304	418
I. Total Internal Load	6,483	6,808	6,960	6,897	6,992

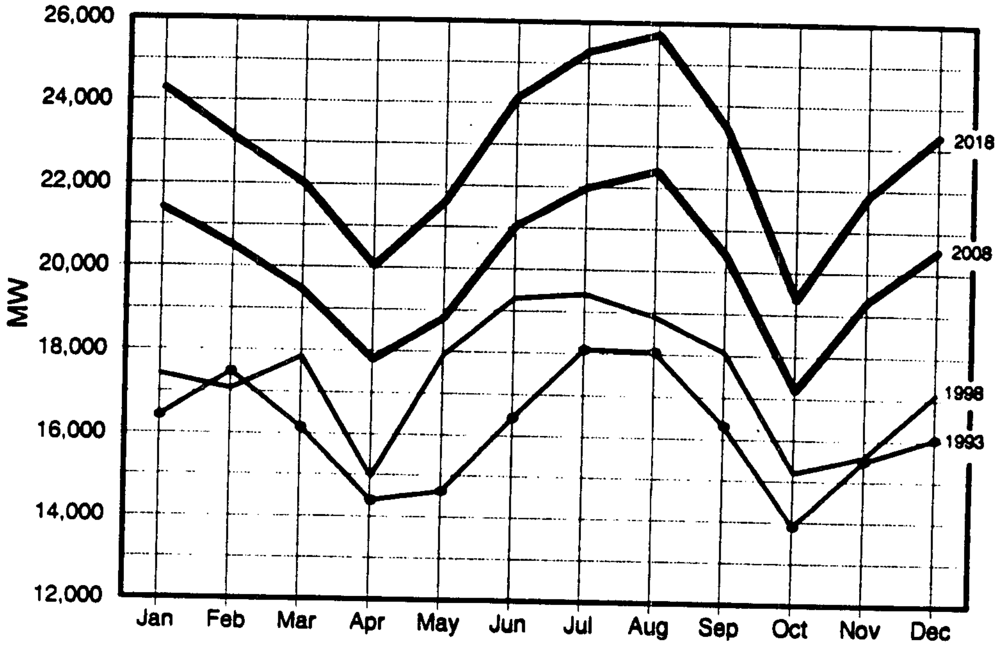
KENTUCKY POWER COMPANY AND AEP SYSTEM
RECORDED AND WEATHER-NORMALIZED PEAK LOAD (MW) AND ENERGY (GWH)
1994-1998

	1994	1995	1996	1997	1998
KENTUCKY POWER COMPANY					
A. Peak Load - Summer					
1. Recorded	1,079	1,136	1,087	1,164	1,213
2. Weather-Normalized	1,077	1,133	1,117	1,194	1,244
B. Peak Load - Winter Following					
1. Recorded	1,363	1,418	1,417	1,299	1,432
2. Weather-Normalized	1,405	1,404	1,409	1,410	1,431
C. Energy					
1. Recorded	6,483	6,808	6,960	6,897	6,992
2. Weather-Normalized	6,534	6,733	6,908	6,956	7,095
AEP SYSTEM					
A. Peak Load - Summer					
1. Recorded	18,070	19,516	18,864	19,119	19,414
2. Weather-Normalized	18,650	19,167	19,049	20,259	19,710
B. Peak Load - Winter Following					
1. Recorded	18,633	19,557	19,381	17,841	18,546
2. Weather-Normalized	19,253	19,255	19,051	19,345	18,327
C. Energy					
1. Recorded	109,273	113,382	115,948	116,136	117,071
2. Weather-Normalized	109,788	112,298	115,594	117,287	118,133

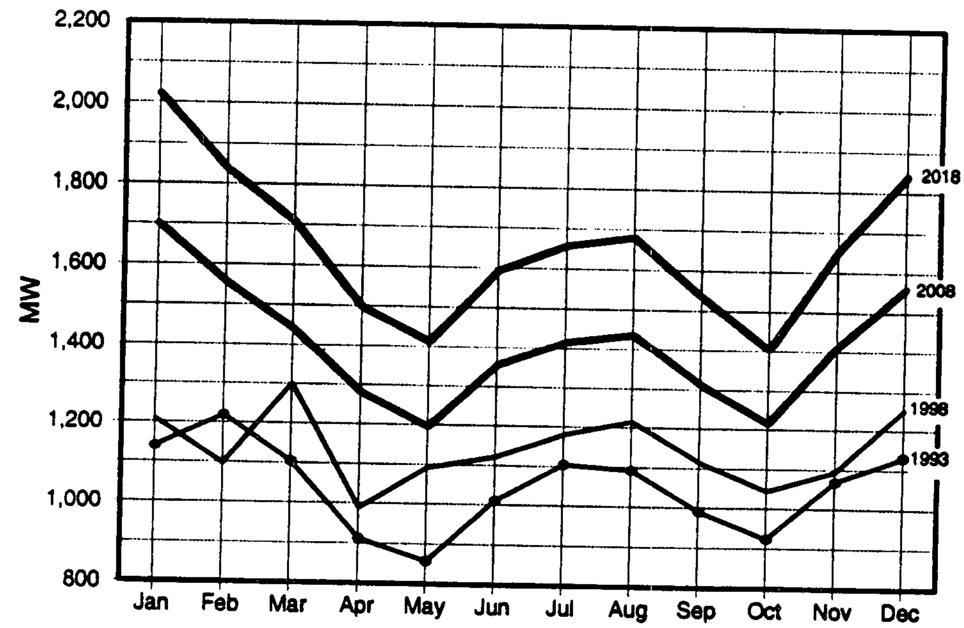
Exhibit 2-31

AEP SYSTEM AND KENTUCKY POWER COMPANY PROFILES OF MONTHLY PEAK INTERNAL DEMANDS 1993, 1998 (ACTUAL) 2008 AND 2018

AMERICAN ELECTRIC POWER SYSTEM



KENTUCKY POWER COMPANY



KENTUCKY POWER COMPANY LOAD FORECAST
DATA SOURCES OUTSIDE THE COMPANY

DATA SERIES	FREQUENCY	GEOGRAPHIC	INTERVAL	SOURCE	ADJUSTMENT
Average Daily Temperatures at time of Daily Peak Load	Daily	Selected weather stations throughout the AEP System	1975-1998	NOAA (1)	None
Heating and Cooling Degree-Days	Monthly	Selected weather stations throughout the AEP System	1/75-6/98	NOAA (1)	Annual Sums used in long-term models
FRB Production Index, Manufacturing	Monthly and Quarterly	U. S.	1975:1-1998:2 1998:3-2019:4	BOG/FRB (3) RFA (2)	Forecast allocated to months for short-term models; Annual averages used in long-term models
CPI-All Urban Wage Earners	Quarterly	U. S.	1975:1-2019:4	RFA (2)	Annual averages used in long-term models
Index of Producer Prices-Industrial Commodities	Quarterly	U. S.	1975:1-2019:4	RFA (2)	Annual averages used in long-term models
U. S. and Kentucky Natural Gas Prices by Sector	Annually	U. S.	1973-1997	DOE/EIA (4)	None
U. S. Coal Production and Consumption	Annually	U. S.	1975-2019	DOE/EIA (5)	None
Kentucky Coal Production	Annually	Selected Kentucky Counties	1975-1997	DMMCK (6)	None
Employment (Total and Selected Sectors), Personal Income and Population	Annually	Selected Kentucky Counties	1975-2019	W&P (7)	None

Source Citations:

(1) "Local Climatological Data," National Oceanographic and Atmospheric Administration.
(2) September 1998 Forecast, RFA.
(3) Board of Governors of Federal Reserve System, "Federal Reserve Statistical Release," 1975-1998
(4) U. S. Department of Energy/Energy Information Administration "Natural Gas Monthly" and "Natrual Gas Annual," Selected Issues.
(5) U. S. Department of Energy/Energy Information Administration "1998 Annual Energy Outlook" and "*Quarterly Coal Report*," *Selected Issues*.
(6) Department of Mines and Minerals, Commonwealth of Kentucky "Annual Report," Selected Issues.
(7) "CEDDS 1998, The Complete Economic and Demographic Data Source," Woods & Poole Economics.

Kentucky Power Company
Residential Energy Sales
1996-1998
Actual vs. 1996 IRP Forecast

	Residential Energy Sales - GWH				Heating Degree Days			
Year	Actual	1996 Forecast	GWH Difference	% Difference	Actual	Normal	HDD Difference	% Difference
1996	2,191	2,133	58	2.7	4,878	4,665	213	4.6
1997	2,197	2,182	15	0.7	4,707	4,665	42	0.9
1998	2,156	2,223	-67	-3.0	3,874	4,665	-791	-17.0

Kentucky Power Company
Seasonal Peak Demands
1996-1998
Actual vs. 1996 Forecast

Summer Peak Demand - MW				
Summer	Actual	1996 Forecast	MW Difference	% Difference
1996	1,087	1,184	-97	-8.2
1997	1,164	1,235	-71	-5.7
1998	1,213	1,257	-44	-3.5
Summer	Weather Normalized	1996 Forecast	MW Difference	% Difference
1996	1,117	1,184	-67	-5.7
1997	1,194	1,235	-41	-3.3
1998	1,244	1,257	-13	-1.0

Winter Peak Demand - MW				
Winter	Actual	1996 Forecast	MW Difference	% Difference
1996/97	1,417	1,397	20	1.4
1997/98	1,299	1,422	-123	-8.6
1998/99	1,432	1,450	-18	-1.2
Winter	Weather Normalized	1996 Forecast	MW Difference	% Difference
1996/97	1,409	1,397	12	0.9
1997/98	1,410	1,422	-12	-0.8
1998/99	1,431	1,450	-19	-1.3

3. DEMAND-SIDE MANAGEMENT PROGRAMS

3. DEMAND-SIDE MANAGEMENT PROGRAMS

A. GENERAL

Recognizing the increasingly competitive environment and the prospect of deregulation and restructuring in the electric utility industry, electric power suppliers can be expected to optimize their operations and compete for a share of the market, based on providing efficient service and fair prices. In this regard, according to economic theory, the fair price of goods and services is ultimately determined in the marketplace. For the electric power industry, legislative and regulatory initiatives have already been initiated and developed, or are in the process of being developed, on both the state and federal levels, with the goal of transitioning the industry to operate on a "fully" competitive basis as soon as practically feasible. AEP/KPCo believes that a competitive environment will ensure fair and reasonable prices. In a world where energy suppliers compete for customers, the demand-side management (DSM) services packaged in the suppliers' offerings will be one of the factors upon which customers base their decisions. The marketplace will then automatically establish the appropriate level of DSM activity.

Also, it must be recognized that the nature of DSM's role has changed over the past few years as a result of dramatically shifting trends in the regulatory and competitive arenas. In view of the increasing competition in the industry, the concept of "cost-effectiveness," as applied to DSM, has shifted from the traditional, regulation-based long-term perspective to the more appropriate market-based short-term perspective. For the AEP System, this has resulted in a reduction of the expected future number and overall load impact of cost-justified DSM programs, compared to previous DSM forecasts. It is AEP/KPCo's belief that the natural trend toward reduced DSM activity will continue in the future. However, the level of DSM activity in each AEP jurisdiction will vary, depending on the regulatory climate, timing of deregulation and various economic factors, such as potential program participation and cost-effectiveness. Additionally, the market for DSM activity will be based on energy-efficiency products and services that will be offered to customers by both energy suppliers and energy services companies.

Each AEP operating company has proceeded at its own DSM implementation pace because the business climate, regulatory climate, customer attitudes and overall DSM potential have varied from region to region. Also, DSM component program costs, lost revenues and incentives are not recoverable on a consistent basis among the state jurisdictions. Therefore, the particular DSM programs implemented in one AEP jurisdiction may not necessarily be implemented in other AEP jurisdictions.

AEP/KPCo is fully appreciative of the current regulatory climate and DSM potential in Kentucky. In this regard, the Company has been continually working with the KPCo DSM Collaborative (which was established in November 1994 to develop KPCo's DSM plans) to ensure that DSM programs are implemented as effectively and efficiently as possible and are helping customers save energy. For example, with Commission approval, the Residential Mobile Home New Construction Program was expanded from an educational program to a full-scale implementation program, offering incentives to both trade allies and new mobile home buyers to encourage the purchase of new high-efficiency mobile homes. These programs, along with other Commission-approved DSM programs for the year 1999, are described in detail in the KPCo DSM Collaborative Report filed with the Commission on August 16, 1999.

While there has always been a great deal of uncertainty over projections of DSM impacts, within the past few years the future of DSM has become even more uncertain due to the likelihood of impending electric utility competition for retail customers. The Company anticipates that, while energy efficiency assistance will continue to be provided to its customers for the foreseeable future, programs aimed at certain classes of customers may no longer be appropriate. For example, the SMART® Audit and SMART® Incentive Programs were discontinued in the KPCo industrial sector at the end of calendar year 1998, with the approval of the KPCo DSM Collaborative. This resulted from the lack of customer participation in those programs and the small target population, due to the industrial class opt-out provision and the types of industrial customers operating in the KPCo service territory. Additionally, other DSM programs were discontinued because of the changing economic factors involved and/or the projected decreases in future participation levels. For example, the Compact Fluorescent Bulb Program was discontinued at the end of calendar year 1996 as a result of decreased customer acceptance of the program, as evidenced by customer participation that fell well below the anticipated levels. Also, the Energy Fitness Program was discontinued in May 1999 because of reduced participation levels and increased promotional and installation costs. The Collaborative agreed to discontinue both of those programs after alternative delivery mechanisms had been examined. Nevertheless, the Company has continued the KPCo Collaborative DSM programs in 1999, with Commission approval, and has also requested approval to continue the DSM programs through 2002.

Increasing appliance efficiency standards and years of customer educational programs will make energy efficiency the normal practice in the future. Although the regulatory climate, along with various economic factors, will determine the level of KPCo's DSM activity in the future, no new recruitment of DSM conservation program participants is being projected for the AEP System beyond the year 2004.

B. DSM GOALS AND OBJECTIVES

The planning philosophy of the AEP System has recognized for many years the need to develop the system's supply and its demand in a compatible manner in order to optimize the utilization of the system's investment in power supply facilities, and to thereby reduce, to the greatest extent possible, the cost of electric power and energy to the consumer. In the implementation of this planning philosophy, the AEP System has pursued a variety of avenues. As a result, the matching between its supply and demand characteristics is, today, much closer than it would be otherwise.

Today's DSM programs continue to encourage the wise and prudent use of electricity, stressing activities that are cost-effective, promote efficiency, conserve, and alter consumption patterns. These programs are intended to benefit the consumer and conserve natural resources.

Conservation activities and expanded use of high-efficiency equipment have been fostered within the marketplace through the Company's DSM programs. Customers, builders, dealers and contractors have been and are continuing to be educated as to the merits of conservation and high-efficiency equipment. To be effective, programs have been tailored to meet local and regional needs and customer characteristics. Several specific objectives of the Company's DSM activities have included:

- Promoting energy conservation to all customers;
- Reducing future peak demands;
- Continuing efforts and cost-effective programs designed to provide the best possible service to customers;
- Promoting electric applications that improve system load factor;
- Striving for retention of existing customers;
- Encouraging new off-peak electrical applications; and
- Providing guidance and assistance to customers facing equipment replacement decisions

A demonstration of the Company's commitment to energy conservation is reflected by AEP's involvement in the U.S. Environmental Protection Agency's (EPA's) Green Lights Program. Since joining the EPA's Green Lights Program as a Utility Ally in 1992, AEP surveyed all of its 2,700 facilities, totaling 12.2 million square feet, and upgraded the lighting in 6.5 million square feet in accordance with EPA's profitability criteria. This upgrading applied to approximately 80% of the facilities and 93% of the space deemed economical. The total cost of the program for the period 1992-1997 was $13.1 million. The estimated annual energy savings is about 23 million kilowatt-hours.

As a result of such efforts, in March 1998, AEP was awarded EPA's Green Lights Ally of the Year Award, in recognition of environmental leadership in this area. AEP has plans to re-survey lighting space to consider upgrading additional facilities and install lighting to meet Green Lights standards in the renovation of existing facilities and for any new construction.

C. CUSTOMER RESEARCH PROGRAMS

Successful demand-side management programs require a thorough understanding of customer electrical usage characteristics, appliance ownership, conservation activities, demographic characteristics, opinions and attitudes, and, perhaps most importantly, customers' needs for electric service. An understanding of these factors helps in the identification of load modifications, which may be advantageous to both the customer and the Company; permits an assessment of their potential impact; and helps in the development of programs to solicit customer participation. Several programs which have been established to obtain this information are discussed below.

C.1. Load Research

The AEP Load Research Program was initiated in the mid-1970s and is currently providing statistical load estimations for about 3 million customers in over 70 individual rate classes across the AEP System's seven-state service area. As part of this program, special load-recording equipment is installed on the premises of over 5,000 customers. Of these customers, about 340 are located in the KPCo service area, and data from them provide statistical load estimates for 9 individual customer classes. In addition, AEP has an extensive System Load Research Program that collects hourly load data from 500 transmission stations serving industrial customers, distribution stations and subtransmission systems. Of those stations, 61 are located in the KPCo service area.

Selected end-use metering projects have also been conducted across the AEP System to estimate load profiles of specific electric appliances and heating/cooling systems. End-use load research metering information associated with the evaluation of DSM programs on appliances such as water heaters, heat pumps, air conditioners, fluorescent lighting equipment, etc., has been collected, as appropriate. With regard to the KPCo Collaborative DSM programs, end-use metering has been conducted in the Residential Mobile Home New Construction Program and the Commercial SMART® Incentive Program.

C.2. Customer Surveys

In the residential sector, since 1980, seven periodic mail surveys of random samples of customers were conducted to provide statistically valid information on appliance saturation, conservation activities and demographic characteristics for such customers in each division across the AEP System. Approximately 250,000 customers have participated in those surveys. Results of the surveys have enabled detailed analyses to be made of market shares and trends for major heating and cooling systems. In addition, profile/segmentation studies were conducted for over 100 market segments defined by type of dwelling, income, end-use, type of market (e.g., new construction or retrofit), gas availability, etc. The identification of these distinct market segments was critical for developing marketing strategies for several DSM programs. Additionally, a residential customer survey verification study was conducted in the KPCo service area in 1994, to determine the accuracy level of the responses to key questions in the 1993 residential survey, and to support the analysis of that survey and enhance the development of future surveys.

A large-sample residential customer survey is scheduled for the AEP service area in late 1999. The magnitude of this survey will be comparable to those surveys conducted since 1980. AEP residential customer surveys are normally implemented at approximately 3-year intervals. Also, commercial or industrial customer surveys are planned to be conducted on a smaller scale, i.e., for specific commercial or industrial DSM programs.

Examples of smaller-scale surveys that AEP has conducted are "short-form" customer demographic surveys of the participants in the Company's DSM programs. These surveys served to provide a basis for comparing the characteristics of the DSM program participants to the population as a whole, to establish baseline information about program participants. Such surveys have aided in providing insights into improving DSM program marketing. For KPCo, customer demographic surveys were conducted during the period 1996-1999 for the residential Energy Fitness, High-Efficiency Heat Pump, High-Efficiency Heat Pump Mobile Home, and Mobile Home New Construction programs, as well as for the commercial and industrial SMART® Audit and SMART® Incentive programs.

C.3. Market Research

The market research activities implemented by KPCo have included DSM market/process evaluation studies. These studies focused on assessing participant satisfaction with the various measures included in each DSM program, assisting in determining the impact on demand by persistence and by the number of freeriders, assessing the effectiveness of the program's delivery mechanisms, assisting in determining additional program/product benefits, and gaining insight into market potential. In carrying out these studies, telephone contacts were utilized to conduct telephone interviews with respondents. The sample size varied by program. Past DSM programs that were evaluated included the residential SMART® Mobile Home Program and the SMART® PAC Program. During 1996-1999, additional evaluation studies were conducted for the residential Energy Fitness, High-Efficiency Heat Pump, High-Efficiency Heat Pump Mobile Home, and Targeted Energy Efficiency programs, as well as the commercial and industrial SMART® Audit and SMART® Incentive programs.

D. GENERAL COMMENTS ON THE DSM EVALUATION PROCESS

DSM screening has been the foundation of AEP's ongoing evaluation and development of DSM programs. As existing technologies mature, new technologies develop, information on customer responses improves, and economic and other factors change, it has been necessary to re-evaluate older DSM options and open investigations into new options.

Over the years, AEP routinely performed extensive analyses on a wide range of DSM options, or "measures." The measures that passed the screening process were grouped into programs for potential implementation. Those programs were, in turn, evaluated to determine their appropriateness for individual jurisdictions within the AEP System. This process has undergone several revisions and the portfolio of DSM programs has been modified, as appropriate.

In the case of KPCo, the DSM Collaborative, since its inception in November 1994, has been the decision-maker on the program-screening process. The Collaborative, whose members represent residential, commercial, and industrial customers, was established to develop KPCo's DSM plans, including program designs, budgets and cost-recovery mechanisms. The Collaborative has continued to review the KPCo DSM programs and modify them as appropriate.

Although the estimated future impacts of AEP's DSM programs have been reduced in the past few years, their overall effects are still material, considering the pertinent developments in this area. In the first place, increased federally mandated energy efficiency standards and years of customer educational programs are making energy efficiency a normal practice. Consequently, much of the efficiency effects associated with DSM programs have been captured, or are embedded, in AEP's base load forecast. Secondly, in anticipation of deregulation, the emphasis of the DSM evaluation process has been shifted from a societal perspective, as reflected in the Total Resource Cost (TRC) test, to the ratepayer perspective, as reflected in the Ratepayer Impact Measure (RIM) test, both of which are defined in the *Standard Practice Manual, Economic Analysis of Demand-Side Management Programs, California Public Utilities Commission and California Energy Commission, December 1987* (California Standard Practice Manual). Thirdly, the uncertainties regarding (a) customer choice of energy supplier in the future and (b) DSM cost-recovery mechanisms in the AEP System's different state jurisdictions serve to hinder the effectiveness and meaningfulness of the DSM evaluation process.

E. DSM PROGRAM-SCREENING PROCESS

E.1. Overview

As previously indicated, during the past few years, the AEP DSM evaluation process for program screening has been shifted from a societal perspective to a ratepayer perspective to reflect the transition to the upcoming competitive environment, where DSM is expected to be market-based, rather than regulation-based. For KPCo, however, the evaluation process considers the DSM program's cost-effectiveness from all perspectives and incorporates cost-recovery mechanisms, as it has since the inception of the KPCo DSM Collaborative in November 1994. In this regard, the Collaborative continues to be the decision-maker on the DSM program-screening process and governs which DSM programs are to be screened for potential implementation in KPCo's service territory.

The Collaborative has re-screened and re-evaluated the DSM programs originally filed for approval with the Commission in September 1995 and implemented in January 1996. Through a continual monitoring process, the Collaborative has utilized a vast amount of data collected from each of the DSM programs to appropriately re-design and re-evaluate the programs so as to improve their cost-effectiveness and better target customers for the programs. Data obtained from load research, customer surveys and market research have all been collected from the various DSM programs, and detailed load impacts have been estimated from the measure information acquired in the field. In this connection, as directed by the Commission, the Collaborative has provided DSM Status Reports every six months since the start of program implementation in 1996, furnishing information on program participation levels, costs and estimated load impacts. Additionally, two KPCo DSM Collaborative Reports were submitted to the Commission, on August 15, 1997 and August 16, 1999, respectively. These reports provided extensive results of the screening and evaluation of each of the DSM programs implemented.

The Collaborative's re-screenings and re-evaluations of the DSM programs resulted in the discontinuation of the Compact Fluorescent Bulb Program at year-end 1996 and of the Energy Fitness Program in May 1999. Also, design changes were made in the Targeted Energy Efficiency Program to improve its cost-effectiveness. In addition, the Mobile Home New Construction Program, which was originally an educational program, was expanded to a full-scale implementation program. Such continual re-screenings and re-evaluations have resulted in providing DSM programs to KPCo customers in a more efficient and cost-effective manner.

E.2. Screening Process

The DSM screening process used by KPCo involved a cost-benefit analysis of each of the DSM programs initially approved by the Collaborative for implementation. This included application of the previously mentioned TRC and RIM tests, as well as the "Utility Cost" (UC) test and the

"Participant" (P) test, as defined in the California Standard Practice Manual. In this connection, the evaluation of the cost-effectiveness of a given DSM program involves the determination of the net present worth of the program's benefits and costs over the study period, which, in this case, was 1999-2019. Under the TRC test, such benefits and costs are viewed from the combined perspective of the utility and the program participant, whereas under the RIM test, the benefits and costs are viewed from the perspective of the ratepayer. The benefits and costs under the UC test are viewed from the perspective of the utility, and under the P test, from the perspective of the program participant.

The major supply-side benefits used in the cost-benefit analysis of DSM programs are avoided energy (production) costs and avoided demand costs (for generation, transmission and distribution). These costs are valued on a marginal $/MWh and $/kW basis, respectively. A detailed approach (peak and off-peak periods, by season) was used to develop avoided production costs. Marginal production costs at peak and off-peak periods in the summer and winter seasons were applied to the appropriate DSM program impacts. The marginal production costs were estimated year-by-year for the 20-year forecast period based on a production cost computer model.

The calculation of avoided demand costs for the DSM programs was based on the average demand impacts for each DSM program's measures coincident with AEP summer and winter peaks. For example, DSM measures targeting the end-uses of space cooling or heating, which produce load impacts in only part of a year, received partial credits for avoided demand costs. Avoided supply-side demand costs were calculated on a levelized basis for the forecast period, based on avoiding the installation of a combustion turbine before the 2005 summer season. Avoided costs for transmission and distribution, expressed in $/kW, were estimated based on historical and projected capital expenditures for general system development projects that are related to load growth.

The benefits, costs and load impacts estimated in the cost-benefit analysis reflect the assumptions regarding replacement and persistence of each measure within the DSM programs over the 20-year study period. Also, the analysis considered the benefits from SO_2 emission credits and expected additional system sales, thereby improving the cost effectiveness of each DSM measure. The reductions in CO_2 and NOx emissions were also estimated in the evaluation; however, no specific dollar values were assigned to them. There are currently no market values for NOx and CO_2 emissions that would allow for estimating an economic value for avoiding emissions of those pollutants via DSM programs.

For purposes of system DSM program screening, it is appropriate to estimate program attributes on an AEP system-wide basis, since supply-side benefits are also considered on the same basis. Information gained from implementation experience in terms of operating company costs, impacts, etc., is incorporated into operating-company-specific cost-benefit program evaluations.

The updated cost-benefit evaluations resulted in 8 expanded DSM programs for the AEP System and KPCo. Exhibit 3-1 provides a list of these programs, including those proposed by the KPCo DSM Collaborative for continuation through calendar year 1999 in an application filed on August

14, 1998 with the Commission. The Commission approved the application on October 27, 1998. Additionally, the Collaborative requested a three-year extension for the proposed DSM programs (except for the Residential Energy Fitness and Industrial SMART® Audit/Financing programs, which were since discontinued) in the KPCo DSM Collaborative Report filed with the Commission on August 16, 1999. The results of the program screening applicable to KPCo are shown in Exhibit 3-2.

The Load Management Water Heating Program is not included in the set of KPCo DSM Collaborative programs, but was approved separately under the Load Management Water Heating Provision of the Residential Service Tariff, which became effective April 1, 1997.

The DSM expansion derived from the program-screening analysis served as an input to PROSCREEN/PROVIEW for the integrated resource analysis. The implementation schedule utilized was based on the current and projected levels of DSM activity in each jurisdiction.

F. IMPACT OF DSM PROGRAMS ON BASE LOAD FORECAST

The estimated total impacts of expanded DSM programs on the projected AEP System and KPCo summer and winter peak demands and annual energy requirements are shown in Exhibit 3-3. A disaggregation of the KPCo DSM impacts, by program, in five-year intervals from 1999 to 2019, is depicted on Exhibit 3-4. These expanded (or incremental) DSM impacts represent the amount by which the base load forecast was reduced in order to determine the resulting adjusted internal demand.

As noted in Exhibit 3-3, at about midway through the forecast period, i.e., the winter of 2009/10, the estimated incremental reduction in the AEP System's base peak internal demand due to the assumed expanded DSM programs is 60 MW, which amounts to 0.3% of peak demand. For the summer of 2009, the corresponding reduction is 18 MW. For KPCo, the expanded DSM estimate for the winter of 2009/10 is 5 MW, which represents a 0.3% reduction in the peak demand. In comparison, KPCo's expanded DSM estimate for the summer of 2009 is 2 MW.

Similarly, the DSM-related incremental energy reduction in the AEP System's internal energy requirements for the year 2009 amounts to 69 GWh, or 0.1% of those requirements. For KPCo, the corresponding DSM estimate is 7 GWh, which also represents a 0.1% reduction in energy requirements.

The projected DSM impacts indicated in Exhibit 3-3 generally increase in time through about 2005, after which they remain relatively stable until after about 2014, due to the persistence of the DSM savings. Beyond 2014, such impacts decrease, due to the previously-noted assumption that there will be no new DSM conservation program participants after 2004, which would result in no replacements of the DSM measures at the end of their service lives. Thus, by the year 2019, for the AEP System, the total expanded DSM impacts on winter-season demand and annual energy would be reduced to levels of 30 MW and 32 GWh, respectively. Similarly, for KPCo, the corresponding reduced total DSM impacts would be 2 MW and 3 GWh.

It should be noted that the KPCo DSM plan, as approved by the Commission, does not extend beyond 1999, although the Company has requested a three-year extension. For the purposes of this report, it was assumed that such planned DSM activity will continue through 2004, at which time the programs would terminate. Details of the original DSM plan may be found in KPCo's application filed with the Commission on September 27, 1995 and approved by the Commission in an Order dated December 4, 1995 (Case No. 95-427). The current implementation status of each program may be found in the KPCo DSM Collaborative Report filed with the Commission on August 16, 1999.

G. SIGNIFICANT CHANGES FROM PREVIOUS DSM PLAN

G.1. Screening Methodology

The 1996 DSM screening methodology included a three-stage measure-screening process, plus a two-stage program-screening process. The 1999 DSM screening methodology reduced the number of screening stages by combining both the measure- and program-screening processes. No new additional qualitative analyses of the AEP System DSM programs were conducted, except for KPCo, through the DSM Collaborative. The DSM Collaborative has continued to be the decision-maker on the program-screening process since the initial design and implementation of the KPCo DSM programs.

G.2. Assumptions

The 1996 DSM analysis was based on the avoided costs of a combustion turbine which was assumed to be installed in 2001. The 1999 analysis is based on 2005 as the year of installation for such capacity.

G.3. DSM Programs and Impacts

In 1996, KPCo's DSM program development, enhanced through the work of the Collaborative, resulted in 6 residential DSM programs and 4 commercial & industrial DSM programs: Energy Fitness, Targeted Energy Efficiency, Compact Fluorescent Bulb, High-Efficiency Heat Pump, High-Efficiency Heat Pump Mobile Home, Mobile Home New Construction, Commercial SMART® Audit, Commercial SMART® Incentive, Industrial SMART® Audit and Industrial SMART® Incentive. In order to continue offering cost-effective energy efficiency and load management options to the Company's customers, and, at the same time, provide programs that are beneficial to customers, the Collaborative decided to discontinue two of the residential programs, Energy Fitness and Compact Fluorescent Bulbs, and the two industrial programs, Industrial SMART® Audit and Industrial SMART® Incentive. Additionally, the Collaborative expanded the residential Mobile Home New Construction Program to full-scale implementation.

In 1996, with the industry on the threshold of a new competitive era, and with increasing concerns regarding rate impacts, the expectations were for reduced levels of DSM activity in future years. In 1999, this expectation still holds and appears to be more realistic today than before, based on more recent developments with respect to deregulation and restructuring in the electric utility industry. In this connection, Exhibit 3-5 provides a comparison of the 1996 and 1999 plans with respect to the estimated DSM-related load impacts on the AEP System and KPCo for the years 2005, 2010 and 2015. Part of the reduction in the DSM impacts indicated on Exhibit 3-5 for the 1999 plan vs. the 1996 plan can be attributed to updated estimates of measure persistence, as well as projected lower levels of DSM activity.

H. OTHER TOPICS

H.1. Effects of Wholesale Competition On DSM Programs Since Their Inception

Wholesale competition has not had an impact on AEP's DSM programs and it is not expected to have any significant impact on AEP's DSM programs in the future. Based on the AEP 1999 Load Forecast, "total sales for resale" (i.e. wholesale) customers account for less than 4% of AEP's total internal annual energy sales, and only about 1% of such sales for KPCo. Also, the Company's DSM programs have been designed and targeted for retail customers. Since a wholesale customer is not an end-user, but rather a buyer and seller of electricity, it would not participate in, nor be affected by, the Company's DSM programs.

H.2. Projected Effects of Competition On DSM Programs

At this time, AEP does not forecast energy sales or peak demand based on a wholesale and retail competitive environment. In this regard, the uncertainty surrounding the assumptions that would need to be made in order to analyze the effects of competition on DSM programs (such as with respect to pricing, timing of competition within each AEP jurisdiction, program participation levels and major supply-side benefits to the AEP System) would make such forecasts speculative and presumptuous, and could not provide any meaningful results. Nevertheless, it is anticipated that increasing competition will reduce potential DSM levels because (1) the cost-effectiveness of the programs would be analyzed from a short-term perspective, rather than from a long-term perspective, and (2) the emphasis of the evaluation would be from a ratepayer perspective, rather than from a societal perspective.

AEP System and KPCO Expanded DSM Programs	
AEP System	**KPCo**
Residential Programs:	
1 Targeted Energy Efficiency	X
2 Energy Fitness*	X
3 High-Efficiency Heat Pump	X
4 High-Efficiency Heat Pump Mobile Home	X
5 Load Management Water Heating	X
6 Mobile Home New Construction	X
Commercial Program:	
SMART Audit/Incentive	X
Industrial Program:	
SMART Audit/Incentive**	-

* The Residential Energy Fitness Program was discontinued in KPCo in May 1999, with Collaborative approval.

** The Industrial SMART® Audit/Incentive Program was discontinued in KPCo at the end of calendar year 1998, with Collaborative approval.

KPCo
1999 DSM Program Screening Summary - 6 Programs

Class	Program	TRC B/C Ratio	TRC B/C Ratio Rank	RIM B/C Ratio	RIM B/C Ratio Rank	UC B/C Ratio	UC B/C Ratio Rank	P B/C Ratio	P B/C Ratio Rank
RES	Energy Fitness	1.96	2	0.81	2	2.11	5	n/a	2
	High Efficiency Heat Pump Mobile Home	2.51	1	0.73	4	2.2	4	3.24	4
	Mobile Home New Construction	1.44	5	0.78	3	2.68	2	1.86	5
	High Efficiency Heat Pump	1.59	3	0.98	1	5.31	1	1.53	6
	Targeted Energy Efficiency	0.42	6	0.27	6	0.42	6	n/a	1
COM	SMART Incentive*	1.51	4	0.62	7	2.52	3	3.4	3

* Assuming 20% freeriders

KPCo and AEP System
Estimated Load Impacts of Expanded DSM Programs
1999-2019

Year	KPCo			AEP		
	Demand Reduction		Energy Reduction (GWh)	Demand Reduction		Energy Reduction (GWh)
	Summer (MW)	Winter Following (MW)		Summer (MW)	Winter Following (MW)	
1999	0	2	2	2	11	6
2000	1	2	4	5	21	18
2001	1	3	4	8	30	28
2002	1	4	5	11	40	40
2003	1	4	6	14	50	50
2004	1	5	7	17	61	62
2005	2	5	7	18	61	69
2006	2	5	7	18	61	69
2007	2	5	7	18	61	69
2008	2	5	7	18	60	69
2009	2	5	7	18	60	69
2010	2	5	7	18	60	68
2011	2	5	7	18	60	68
2012	2	5	7	18	60	68
2013	2	5	7	18	60	66
2014	1	3	7	16	49	65
2015	1	3	5	13	40	53
2016	1	2	4	10	30	43
2017	1	2	3	8	30	32
2018	1	2	3	8	30	32
2019	1	2	3	8	30	32

Note: Expanded DSM program impacts result from installations assumed to be made in the future and are not reflected in the base-load forecast. Impacts of DSM program installations already in-place, i.e., embedded DSM program impacts, are reflected in the base-load forecast.

As of the end of 1998, the estimated aggregate embedded DSM program impacts were as follows:

	Summer MW	Winter MW	Annual Gwh
KPCo	4	16	37
AEP	70	170	326

Since DSM program persistence is less than 100%, these embedded DSM impacts are expected to diminish gradually over the forecast period.

Kentucky Power Company
Estimated Reduction in Energy Requirements
and Demand (At Time of AEP System Peak)
Due to Expanded DSM Programs

	Energy Requirements Reduction (GWH)					Peak Demand Reduction - (MW)									
						Summer					Winter				
	1999	2004	2009	2014	2019	1999	2004	2009	2014	2019	1999/00	2004/05	2009/10	2014/15	2019/20
Residential Programs															
Energy Fitness	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0
Targeted Energy Efficiency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High-Efficiency Heat Pump	0	4	5	5	2	0	1	1	1	1	1	3	3	2	2
High-Efficiency Heat Pump-Mobile Home	1	1	1	1	0	0	0	1	0	0	1	1	1	1	0
New Construction Mobile Home	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Residential	2	6	6	6	2	0	1	2	1	1	2	4	4	3	2
Commerical Programs															
Commerical SMART Incentive	0	1	1	1	1	0	0	0	0	0	0	1	1	0	0
Total	2	7	7	7	3	0	1	2	1	1	2	5	5	3	2

AEP SYSTEM AND KENTUCKY POWER COMPANY
Estimated Reduction in Forecasted Energy Requirements and Peak Demand Due to Expanded DSM Programs For Years 2005, 2010 and 2015

Comparison of 1996 and 1999 Plans

	AEP System		KPCo	
Reduction in Energy Requirements (GWH)	1996 Plan	1999 Plan	1996 Plan	1999 Plan
2005	202	69	71	7
2010	174	68	56	7
2015	96	53	35	5
Reduction in Winter Peak Demand (MW)				
2005/06	321	61	42	5
2010/11	315	60	39	5
2015/16	240	40	27	3

4. RESOURCE FORECAST

4. RESOURCE FORECAST

A. RESOURCE PLANNING OBJECTIVES

The primary objective of power system planning is to assure the reliable, adequate and economical supply of electric power and energy to the consumer, in an environmentally compatible manner. Implicit in this primary objective are related objectives, which include, in part: (1) maximizing the efficiency of operation of the power supply system, and (2) encouraging the wise and efficient use of energy. Achievement of these objectives necessarily involves consideration of supply-side options, including various types of generation resources, as well as demand-side options, involving customer load modification programs.

In the planning of power supply resources for the AEP System, consideration is given to several broad factors, including: (1) reliability, i.e., the ability of the system to provide continuous electric service not only under normal conditions, but also during various contingency conditions, (2) economy, so as to minimize the cost of power supply on a long-term basis, (3) environmental compatibility, (4) financial requirements, and (5) flexibility, i.e., the extent to which plans for future resources can be adjusted to meet changing conditions.

B. KPCO/AEP SYSTEM RESOURCE PLANNING CONSIDERATIONS

B.1. General

Kentucky Power is one of the operating companies of the AEP System, which is planned and operated as a completely integrated electric power system. In this regard, the System's major operating companies are electrically connected by a high-capability transmission system extending from Virginia to Michigan. This transmission system, composed of a 765-kV, 500-kV 345-kV, and 230-kV extra-high-voltage network, together with an extensive underlying 138-kV transmission network, has been planned and constructed to provide an adequate and reliable means for integrating the AEP System's major power generating plants with its principal load centers. In addition, this transmission network is interconnected with 25 neighboring electric systems by 144 interconnections.

Maps of the generation and transmission facilities for KPCo and the AEP System are shown in Exhibits 4-1 and 4-2, respectively. Exhibit 4-3 lists the AEP interconnections in the Kentucky area.

KPCo's Big Sandy generating plant is centrally dispatched in conjunction with the plants of other AEP System operating companies from the AEP System Control Center located in Columbus, Ohio. This process of dispatching all of the system's generating units from one control center enables the AEP System to continuously supply power in the most reliable and economical manner to all of its customers from the combined generating capacity of the AEP System.

For the AEP System as a whole, it is necessary to establish and maintain sufficient generating-capacity resources to assure a reliable bulk power supply to the aggregate load of the combined AEP System operating companies. While the AEP System is planned, constructed and operated as an integrated power system, each operating subsidiary is still responsible for providing adequate generating-capacity resources to supply its own requirements. Under the AEP Interconnection Agreement (which represents the "pool agreement" among the five major AEP operating companies), each member of the pool is responsible for a proportionate share of the aggregate AEP pool generating capacity. Each member must provide -- over time -- sufficient generating capacity to meet its own internal load requirements plus an adequate reserve margin. However, since generating capacity can only be installed in discrete amounts, generally sized by physical, electrical, and economic considerations, there will be temporary imbalances between the load requirements and the generating capability of individual member companies. Whenever a member company's generating capability is insufficient to supply its peak demand, it draws upon the resources of the other AEP companies in accordance with the provisions of the AEP Interconnection Agreement. At other times that company may have generating capability in excess of its own needs, which is utilized as necessary to supply part of the load requirements of the other AEP companies.

Thus, the evaluation of the adequacy and reliability of KPCo's generating capability to meet the current and projected power demands of its customers must be based on consideration of the total generating capability of the AEP System in relation to the aggregate AEP System load (taking into account contractual arrangements with non-affiliated parties).

One of the basic reliability principles pertaining to system planning is the need to maintain a reasonable balance among major system parameters, such as the magnitude of the system load, the size of the largest generating units and plants, the strength of the transmission network, and the strength of interconnections with neighboring power systems. Reliability is enhanced by balancing such parameters not only on a system-wide basis but also within geographic areas of the system. Such balances are planned to provide opportunities not only for enhanced system reliability, but also for taking advantage of economies of scale and greater cost efficiencies in the system's day-to-day operation, all of which ultimately accrue to the benefit of the customers of the individual AEP operating companies.

Currently, and for the near term, the AEP System has adequate generation resources to meet the load requirements of the customers of its operating companies (including KPCo). With the additional capability provided by the projected demand-side and supply-side resources identified in this chapter, the AEP System (KPCo) is expected to have adequate generation resources to serve its customers' requirements throughout the forecast period.

B.2. Development of Reliability Criterion Guideline

B.2.a. Definition of Reliability

For the purpose of this report, generation system reliability (i.e., generation reserve adequacy) is defined as the degree to which the system is able to supply the power requirements of its customers, on demand, during both normal and abnormal conditions. Generation system reliability may be expressed or measured in different ways, such as by the frequency, duration and magnitude of capacity shortfalls. From a planning perspective, the expected reliability performance level of a given generation system over a given period of time provides a measure of the ability -- or, conversely, the inability -- of that system to meet its load requirements continuously throughout that time period.

B.2.b. Reliability Indices

For reliability purposes, a sufficient amount of generating capacity resources is required to meet, in the aggregate, the total demand of the system's customers, and to cover scheduled maintenance requirements and emergency outages of the system's generating units. In this connection, generation system reliability performance indices provide a means of assessing the need for, and timing of, capacity additions, and evaluating the effects on system reliability of various alternative generating unit sizes, types, and performance characteristics.

Reliability indices are typically categorized as either deterministic or probabilistic. Deterministic indices are relatively simple measures, e.g., installed capacity reserve expressed either as a percentage of peak load or in terms of the extent of coverage of the system's largest generating units. Probabilistic indices, on the other hand, are computed using relatively complex mathematical models that typically convolve load and capacity distributions to determine the expected amounts of time that available generating capability is insufficient to serve load.

Deterministic reliability indices are popular due to their simplicity and ease of calculation. However, deterministic indices typically focus on a single point in time, such as the peak load hour during the year. Hence, the extrapolation of those indices to judge the adequacy of an entire year does not provide as complete a picture of that year's reliability as probabilistic indices. Probabilistic methods, such as the Dependence on Supplemental Capacity Resources (DSCR), Expected Unserved Energy (EUE) and Loss-of-Load-Probability (LOLP) approaches, are more meaningful in the sense that they can account for the effects of many pertinent system factors, such as daily and seasonal load profiles, generating-unit sizes, scheduled maintenance requirements and forced outages of the system's generating units. However, the calculation of probabilistic indices generally requires extensive system data input. In view of the relative advantages and disadvantages of both types of indices, many utilities, including AEP, use both deterministic and probabilistic indices in their reliability assessments in order to provide multiple perspectives in the evaluation of power supply reliability.

B.2.c. Need for Adequate Reserves

Reserve margin is that portion of the capacity resources which exceeds peak demand. Continuity of supply cannot be assured unless the utility has not only enough generating resources to supply its customers' peak demands, but also an additional amount of reserve margin to provide for contingencies.

In the near-term, reserve margins provide a utility with flexibility and a margin of safety for daily operation. Reserve margins are needed in daily system operation because the utility must keep an amount of operating, but unloaded, capacity on line to maintain scheduled power flows on tie lines and to permit satisfactory regulation of system frequency. Reserve margins also provide protection against combinations of contingencies, whose total magnitude is both variable and uncertain. Those contingencies include, but are not limited to, the following:

- generating unit forced outages;
- reductions in generating unit capability due to equipment failures or adverse operating conditions;
- reductions in electrical output due to transmission restrictions;
- reductions in generating unit capability (or even shutdowns of units) due to actions by regulatory authorities; and
- load increases due to extreme weather conditions.

An adequate reserve margin also provides for carrying load during planned shutdowns of generating units for routine maintenance or major modifications.

On a long-term basis, in addition to the factors mentioned above, reserve margins are needed to provide for unanticipated increases in electricity demand growth, delays in commercial operation of scheduled generating unit additions, and unanticipated regulatory or legislative actions.

B.2.d. AEP's Capacity Reserve Analysis Program

Exhibits 4-4 and 4-5 illustrate the basic concepts underlying an analytical approach to the evaluation of the reliability associated with the capacity reserves installed on the AEP System. As Exhibit 4-4 indicates, such evaluation involves developing the interrelation between daily peak load, on the one hand, and available capacity, on the other hand, for each day in the study period, taking into account scheduled maintenance requirements, capacity deratings, and contingencies such as forced generating-unit outages. On any particular day, the resulting capacity margin at the time of peak load can be either positive (a capacity margin surplus) or negative (a capacity margin deficiency), depending upon the particular load and capacity conditions involved.

This basic concept of analyzing the capacity reserve situation of a peak hour of a particular day can also be extended to all of the days in the study year so as to develop a distribution of daily capacity margins, in the form of a histogram or a cumulative distribution, as illustrated in Exhibit 4-5. Such distributions can be developed on a historical basis for a given year by reconstructing and interrelating actual load and capacity conditions from company operating records. Similarly, for a given future year, a distribution can be developed by interrelating simulated load and capacity models, in which forced generating-unit outages are treated in a random, probabilistic manner.

It is significant to note, as indicated in Exhibit 4-5, that the capacity margin distribution curve serves to provide a means of quantitatively measuring -- in several different dimensions -- the generation reliability performance of a power system, i.e., the ability of the system to meet its load obligations. In particular, the capacity deficiency region of the capacity margin distribution provides a measure of the extent of utilization of supplemental capacity resources (such as interruptible-load curtailments and emergency power purchases from neighboring power systems) required during the study year in order to accommodate the capacity deficiencies and thereby avoid actual loss of load.

The basic concepts described above for evaluating a power system's installed reserves are embodied in AEP's Capacity Reserve Analysis (CRA) computer program. This program, which simulates the operation of the power system for each hour of the study period, calculates the range of daily capacity margins -- and the associated reliability performance level -- likely to occur throughout the study period, based on the relationships between: (1) a capacity model that reflects, for each hour, scheduled outages and seasonal deratings of generating units in a deterministic fashion, as well as full and partial forced outages in a random or probabilistic fashion, and (2) an hourly load model for the study year. More specifically, for a given study year, the program performs the following steps:

1. Determines for each week in the year a load-duration curve for:
   a. the weekday daily peak hours;
   b. the on-peak period hours; and
   c. the off-peak period hours;

2. Calculates, for each week, on- and off-peak period probability distributions of available system capacity, considering scheduled maintenance, seasonal ratings, and forced and partial outage rates;

3. Mathematically convolves the capacity distributions with the corresponding load-duration curves, with proper adjustments made for firm or committed sales and purchases with neighboring power systems, to determine probability distributions of capacity margins; and

4. Sums the resulting distributions of capacity margins for each week and for the entire year, to produce weekly and annual statistics for the daily peaks, on-peak periods, and all hours.

B.2.e. Interrelationships Among Key Parameters

In the evaluation and determination of generation reserve requirements, consideration must be given to the interrelationships among a number of key parameters: system reliability level, average generating-unit availability, and installed reserve margin. In this regard, a change in the generating-unit availability performance can have a significant impact on the system reliability level, just as would a change in the level of installed reserve margin.

Exhibit 4-6 illustrates, for the AEP System, the threefold interrelationship that typically exists among system reliability level (expressed in terms of the expected number of capacity-deficient days in a particular study year), average system on-peak generating-unit availability, and reserve margin. The parametric relationships indicated on Exhibit 4-6 represent the results of sensitivity studies, using the CRA computer program. Such an exhibit aids in determining the reserve margin required to maintain a given level of reliability for a specified system availability rate or, alternatively, in evaluating the effect of availability performance on system reliability.

Significantly, the parametric relationships shown in Exhibit 4-6 generally remain rather stable from year to year, inasmuch as the load and capacity parameters are assumed to remain essentially stable, including the monthly and daily load profiles, and scheduled maintenance requirements. Thus, the concepts underlying the interrelationships reflected in Exhibit 4-6 provide a powerful tool for estimating total capacity requirements in a given year to accommodate a given forecasted load at a specified system reliability level. These interrelationships can also be used to estimate future resource requirements over a span of time.

B.2.f. Reliability Criterion Guideline

For planning purposes, estimation of the AEP System's reserve requirements is premised on the basis that, for nominal projected conditions, a marginal, but satisfactory, level of the expected number of capacity-deficient days (i.e., days in which the AEP System would be seeking emergency assistance from neighboring systems) should be no more than about 5 to 10 % of the number of days in a year, or about 20 to 40 days per year. This assumes that, during those times of AEP capacity deficiency, the neighboring systems will have available the necessary resources to cover those deficiencies. Such a range of reliability levels is intended to reflect the uncertainty inherent in the planning process.

For purposes of analyzing future power supply additions, a reliability level of about 30 capacity-deficient days (about 8% of the days in the year, or about 11.5% of the weekdays) is judged to be appropriate for estimating overall resource requirements. The AEP System projects its average system on-peak equivalent availability to attain 80% or better during the planning period. As can be determined from Exhibit 4-6, assuming an equivalent availability of 80% or better, a reliability level of 30 capacity-deficient days translates to a required reserve margin of 8% or less. However, such reserve margins would not be sufficient to cover both operating reserve requirements and certain outage contingencies at the time of the annual peak demand. In order to provide for operating reserves plus the loss of the largest unit, the AEP System would require a reserve margin of about 12% at the time of the annual peak demand, excluding interruptible load. Thus, for AEP System long-range resource planning studies, a reserve margin of about 12% of firm load obligations has been judged to be a reasonable target.

It should be noted that the target reliability and installed reserve levels indicated above reflect nominal forecasted load and capacity conditions, and assume that sufficient reserves would be available on neighboring power systems to cover the resulting capacity deficiencies expected to occur. During such situations, the AEP System would seek to obtain emergency assistance from its neighboring interconnected systems. As reserve margins on the neighboring systems change, or as the availability performance of AEP's generating units changes, the reliability level judged to be adequate on the AEP System may need to be adjusted accordingly. Before commitments to specific resource additions are made, the then-prevailing circumstances must be considered, and appropriate judgments applied.

C. INTEGRATED RESOURCE PLANNING PROCEDURE

The AEP System's resource planning process embodies Integrated Resource Planning (IRP) concepts, in which both supply-side options and demand-side options are analyzed to formulate potential resource plans.

The flow chart shown on Exhibit 4-7 depicts an overview of the steps involved in the IRP procedure that was used to develop the resource expansion presented in this report. These steps are as follows:

1. Development of the base-case load forecast.
2. Determination of overall resource requirements.
3. Identification and screening of supply-side resource options.
4. Identification and screening of DSM options.
5. Integration of supply-side and demand-side options.
   a. Determination of impact of DSM programs on base-case load forecast.
   b. Development of supply-side resource expansion with expanded DSM.
6. Analysis and Review.

A discussion of these six steps follows.

C.1. Development of Base-Case Load Forecast

The development of the base-case load forecast is presented in Chapter 2. That initial forecast excludes adjustments for potential future (i.e., expanded) DSM programs.

C.2. Determination of Overall Resource Requirements

The determination of overall resource requirements includes an evaluation of the adequacy of existing generating capability to meet the future forecasted load requirements, taking into account assumed changes to that capability (reratings, retirements, etc.) and committed power transactions with other utilities. These items are discussed below.

C.2.a. Existing Generation Facilities

As noted on Exhibit 4-8, KPCo's existing installed generating capability (as of January 1, 1999) is 1,060 MW, which consists of the Big Sandy generating plant, located in Louisa, Kentucky. KPCo also has a unit power agreement with AEP Generating Company (AEG), an affiliate, to purchase 390 MW of capacity through 1999 (or 2004, if extended) from the Rockport Plant, located in southern Indiana. This report reflects the assumption that the KPCo-AEG agreement will expire on December 31, 2004.

In comparison, the AEP System's total generating capability is 23,759 MW (or 23,054 MW, after adjusting for 705 MW of unit power sales). The generating facilities which comprise this capability are listed in Exhibit 4-9. Actual production cost and operating information for each of the System's steam generating plants for the year 1998 is provided in Exhibit 4-10.

Also, changes in the status or ratings of existing generating units assumed to occur during the forecast period are shown on Exhibit 4-11.

C.2.b. Power Arrangements With Other Utilities

AEP's currently committed power transactions with other utilities are summarized on Exhibit 4-12. In addition to the commitments shown on the exhibit, AEP operating companies have entered into other formal arrangements, including power transactions, as discussed briefly below.

Four AEP System companies (Indiana Michigan Power, Appalachian Power, Columbus Southern Power, and Ohio Power) are among the fifteen investor-owned electric utilities in the Ohio Valley region which sponsored the formation in 1952 of the Ohio Valley Electric Corporation (OVEC) and its subsidiary Indiana-Kentucky Electric corporation (IKEC) for the purpose of supplying the electric power requirements of the Federal Government's Portsmouth Area Project, which was originally under the responsibility of the Atomic Energy Commission, and later the Department of Energy (DOE). Effective July 1, 1993, the United States Enrichment Corporation began leasing the uranium enrichment facilities from DOE and assumed DOE's responsibilities for operating the uranium enrichment enterprise. The Sponsoring Companies are entitled to purchase from OVEC their participation share of any energy which OVEC has available after DOE's purchase under the OVEC/DOE contract. The Sponsoring Companies also are obligated to supply limited amounts of power to the Portsmouth Area Project when the available OVEC System generating capacity is inadequate to supply the DOE demand.

Ohio Power Company owns Unit 1, and Buckeye Power, Inc. owns Units 2 and 3, of the three-unit Cardinal Plant, located in Brilliant, Ohio. Buckeye supplies the power requirements of the Ohio rural electric cooperatives from its Cardinal units under terms of an agreement with Ohio's investor-owned electric utilities, whereby power is transmitted over their transmission systems to the cooperatives. Ohio Power Company provides Buckeye with backup power when Buckeye's Cardinal units are out of service for planned or emergency maintenance and, in turn, Ohio Power is entitled to utilize any capacity from the units not needed to supply Buckeye's load. Also, the Buckeye Power units are jointly dispatched with the AEP System generating units. For planning purposes, Buckeye Power capacity and load are combined with AEP capacity and load.

C.2.c. Demands, Capabilities and Reserve Margins Assuming No New Resources

Exhibits 4-13 and 4-14 provide a projection of the AEP System's peak demands, capabilities and reserve margins for the summer and winter seasons, respectively, from 2000 through 2019, assuming no new resources are added onto the system. The projected data reflect the base-case load forecast, AEP's contractual arrangements with Buckeye Power, committed sales to non-affiliated utilities, and the amount of AEP's industrial interruptible load that can be interrupted at the time of the seasonal peak. Due to the contractual nature of these interruptible loads, they are excluded from total load in determining the future capacity needs on the system.

The projected capabilities assume retirements of certain existing generating units and exclude the currently committed unit power sales (from Rockport Units 1 and 2) to other utilities. In this connection, the forecast reflects the termination of those unit power sales and the resulting recapture of that capacity (455 MW in 2000, and 250 MW in 2010) for the benefit of the AEP System. Based upon those assumptions, reserves are projected to drop below 12% of peak demand, excluding interruptible load, by the summer of 2004, and continue to decrease thereafter, as graphically depicted on Exhibit 4-15.

The corresponding projections of Kentucky Power Company's peak demands, capabilities and reserve margins are shown on Exhibits 4-16 and 4-17 for the summer and winter seasons, respectively.

C.3. Identification and Screening of Supply-Side Resource Options

C.3.a. Identification of Capacity Options

As indicated in Exhibit 4-7, the IRP procedure normally conducted by AEP involves the identification and screening of a variety of generating capacity options, including different unit types and sizes, as appropriate. Consideration is given to capacity alternatives that could be categorized by their mode of operation, which includes the traditional categories of base load, intermediate and peaking, as well as an "intermittent" category, which includes capacity resources whose availability is variable and is not dispatchable under the utility's control. The types of capacity options considered under these various categories are identified below.

Base Load Capacity
1. Pulverized coal with flue gas desulfurization
2. Coal gasification combined-cycle (CGCC)
3. Nuclear – advanced pressurized water reactor (APWR)

Intermediate Capacity
1. Gas-fired combined cycle
2. Fuel cells – molten carbonate (MCFC)

Peaking Capacity
1. Gas-fired combustion turbine
2. Advanced battery energy storage

Intermittent Capacity
1. Conventional hydroelectric
2. Wind turbine farm
3. Solar photovoltaic

At this time, however, in view of (1) the strong likelihood of the industry being restructured during the forecast period, (2) the many uncertainties associated with the future of the industry and the matter of customer choice, and (3) the expectation that AEP will not require new capacity resources until about the year 2005, the determination of the types, sizes and means of acquisition of such resources (e.g., by self-building or purchasing from outside entities) is highly uncertain. Therefore, for the purposes of this report, rather than conducting detailed screening analyses, as was done previously, and essentially speculating as to the specific type, size, or means of acquisition of future individual generation resources, it was deemed appropriate and prudent to consider these future resources on a generic, "undesignated," basis, and to report such resources in terms of the aggregate MW of resource additions required (in multiples of 100 MW) for each of the forecast years affected.

C.3.b. Retrofit or Life Extension of Existing Facilities

Past experience has indicated that, with proper maintenance and operation, coal-fired units can expect to achieve nominal operating lifetimes on the order of 35-40 years. Of course, the achievable lifetime is highly unit-specific. Some units have experienced faster deterioration than others, but, in general, nominal service lifetimes can be expected to fall in that 35-40 year range.

Utilities today, including AEP/KPCo, have a great incentive to keep existing units operating as long as possible, so as to postpone the need for adding costly new replacement capacity. "Life extension" has become an important supply-side consideration for many utilities in developing integrated resource plans. With respect to large steam generating units, such as those on the AEP System, the results of programs that have been developed to attempt to achieve longer operating lifetimes are still to be demonstrated, since very few large steam generating units in the U.S. have had operating experience beyond 40 years of service.

The AEP System does not carry out life extension of its generating units in the commonly accepted sense of that term, whereby major modifications, refurbishments or replacements are made at the end of a unit's nominal life in order to enable it to operate for an additional 10-20 years. Rather, AEP's practice is one of "life optimization," by which it regularly inspects and assesses the condition of its units, and makes those repairs or replacements as needed in the normal course of unit maintenance to maintain safe, reliable and economic operation of the units. Accordingly, programs have been developed by AEP to attempt to achieve optimal operating lifetimes, and to do so as economically as possible. Thus, rather than waiting for major equipment failures or other needs for large-scale refurbishment to occur, AEP's life optimization programs are implemented over a number of years commencing several years prior to the end of a unit's "traditional" lifetime. The work is planned over this long period, so as to minimize its total cost and the outage time required. The assumed retirement dates shown on Exhibit 4-11 reflect extended unit lifetimes based on these life optimization concepts.

C.3.c. External Resource Options

C.3.c.1. Purchased Power from Other Utilities

With the absence of specific information available regarding potential purchases from other utilities, purchased power was not selected as an option for this expansion. However, this option would be evaluated as circumstances warrant and specific pertinent option information becomes available.

C.3.c.2. Non-Utility Generation

On the AEP System, the existing amount of non-utility generation available for purchase aggregates to less than 1 MW. However, AEP has committed to purchase power, through Appalachian Power Company, from Summersville Hydro, a PURPA Qualifying Facility (QF), starting in January 2001. Expected power purchase levels from this QF are 25 MW and 17 MW for the winter and summer seasons, respectively.

Non-utility generation as a resource option is evaluated as resource needs and specific opportunities arise and pertinent information becomes available before any final decision and commitments are made for specific resources.

C.4. Identification and Screening of DSM Options

A discussion of the identification and screening of DSM options is presented in Chapter 3. That chapter also provides the screening results, i.e., the AEP/KPCo DSM programs selected in conjunction with the development of the integrated resource expansion.

C.5. Integration of Supply-Side and Demand-Side Options

This step involves the development of an integrated resource expansion reflecting the implementation of expanded DSM programs. In this expansion, all DSM measures and programs which passed the screening process are assumed to be implemented in various jurisdictions across the AEP System. Implementation is assumed to be accomplished through a schedule specific to each jurisdiction.

C.5.a. Determination of Impact of DSM Programs on Base Case Load Forecast

The DSM program impacts reflected in the integration analysis are discussed in Chapter 3.

C.5.b. Development of Supply-Side Resource Expansion With Expanded DSM

Exhibits 4-18 and 4-19 show the supply-side resource expansion with expanded DSM, along with the corresponding projected AEP System peak demands, capabilities, and margins, for the summer and winter seasons, respectively, after adjusting the demands for DSM impacts. The resource expansion is portrayed as "blocks" of undesignated generation resource additions (in multiples of 100 MW) required to meet the target reserve margin of 12%, as depicted graphically on Exhibit 4-20.

For the purposes of this report, the expansion shown on Exhibits 4-18 and 4-19 represents the current integrated resource plan. Under this plan, in addition to the expanded DSM levels indicated, starting in the year 2005, the AEP System could require up to about 9,100 MW of new generating capacity through 2019.

In a broad sense, the capacity expansion portrayed on Exhibits 4-18 and 4-19 defines the timing and amounts of new resources required to serve the AEP System's future loads in a reliable manner. When resource commitments must be made, all options will be considered, including both self-build and external resource options.

Exhibit 4-21 and 4-22 show KPCo's corresponding projected summer and winter peak demands, capabilities, and reserve margins for the forecast period, after adjusting the demands for DSM impacts, and assigning the AEP System generation resource additions shown on Exhibits 4-18 and 4-19 to the member operating companies. To allocate such blocks of resource additions equitably, each successive resource block was generally assigned to the operating company, or combination of operating companies, with the lowest reserve margin. In instances in which an individual resource block could be allocated among operating companies, it was divided into several parts (in multiples of 100 MW), as appropriate. As a result, KPCo was assigned 1,100 MW of new resource additions through the year 2019.

If it is assumed that the undesignated blocks of resource additions are all combustion turbine units, then KPCo's energy resources might be allocated as shown on Exhibit 4-23, which indicates, for the period 2000-2013, projected annual internal energy requirements, energy resources (generation and purchases) and energy inputs by primary fuel type.

C.6. Analysis and Review

C.6.a. Reliability

The AEP System integrated resource plan presented herein is expected to provide adequate reliability over the forecast period, under the following assumptions:

1. Load-growth projections as forecasted in the "base case", averaging about 1.4% per year for peak-demand growth;

2. Average on-peak equivalent generating-unit availability of 80% or greater;

3. Additions, retirements and reratings of generating units (along with other capability changes, including the return of capacity upon termination of unit power sales) as indicated on Exhibit 4-11;

4. Expanded DSM impacts as estimated, amounting to summer peak demand reductions of 18 MW and 8 MW for years 2009 and 2019, respectively; and winter peak demand reductions of 60 MW and 30 MW for 2008/09 and 2018/19, respectively.

5. Interruptible loads as assumed in the base-load forecast, amounting to 674 MW at time of summer peak, and 681 MW at time of winter peak.

6. Lead time that is sufficient for the determination and acquisition of specific additional generation resources required in the future.

As a measure of reliability, the projected number of capacity-deficient days on the AEP System is not expected to exceed about 10 days per year throughout the forecast period. Such reliability performance reflects the addition of new generation resources commencing in the year 2005.

C.6.b. Uncertainties/Sensitivity

The long-term resource expansion reported herein is simply a snapshot of the future at this time, based on current thinking relative to various parameters, each having its own degree of uncertainty. The expansion reflects, to a large extent, assumptions that are subject to change. Other parameters that will affect future outcomes are the impact of competition and the continuing impact of open-access transmission. As the future unfolds, and as parameter changes are recognized and updated, input information must be continually evaluated, and resource plans modified as appropriate.

Some key factors that can affect the timing of future capacity additions are the magnitude of future loads and capacity reserve requirements. The magnitude of the future load in any particular year is a function of load growth and DSM impacts. Capacity reserve requirements, as discussed previously in this chapter, could vary depending on the desired reliability level and average system generating-unit availability.

Exhibit 4-24 summarizes the results of a sensitivity analysis, in terms of the year in which additional generation resources could be required on the AEP system. Taking into account possible variations in the parameter values, such resources could be required as early as 2003 with the high forecast, to as late as 2007 with the low forecast. With a 12% minimum reserve criterion, the primary determinant of the year of first generation resource additions is the load forecast.

The results of sensitivity analyses demonstrate that changes in assumptions regarding key parameters could result in significant changes in the IRP expansion. Developments with respect to these parameters are monitored, to reduce uncertainty where possible. In addition, contingency plans to meet scenarios based on alternate assumptions are explored, to ensure that the expansion is flexible enough to be adaptable to meet changes in future circumstances.

C.6.c. Significant Changes from Previous Capacity Expansion Plan

Exhibit 4-25 provides a comparison of the AEP system capacity expansions for the current (1999) integrated resource plan and the previously reported (1996) plan. The exhibit shows that for the 1999 plan, through the year 2016, a total of 7,700 MW of capacity is assumed to be added. In comparison, the 1996 plan shows a total of 9,355 MW being added in the same time frame. Also, whereas the 1996 expansion plan incorporated specific types and sizes of new-unit additions, the 1999 plan reflects the addition of blocks of undesignated new generation resources, sized in multiples of 100 MW.

D. OTHER CONSIDERATIONS AND ISSUES

D.1. Transmission System

The AEP System's strong transmission network and its strong interconnections with neighboring utilities are of great value to each of the AEP operating companies in terms of reliability and increased flexibility of operation. AEP and its operating companies continually review the need for reinforcement (i.e., improvements) to their transmission (and distribution) facilities, in order to maintain an acceptable level of reliability and flexibility of operation.

The AEP System's ability to meet its customers' future electric needs will be affected by transmission reinforcement projects planned for the future, particularly the Wyoming-Cloverdale 765-kV line (or the alternative Wyoming-Jacksons Ferry 765-kV line), in the southeastern portion of the System's service territory. If such projects are not completed as planned, then the reliability of service to AEP customers would be jeopardized.

In the case of KPCo, a major transmission construction program was recently completed in response to anticipated load growth. This program included the upgrading and reinforcement of the transmission system in the Inez and Tri-state areas of eastern Kentucky. The principal project in this program was the Big Sandy/Inez project, which included the construction of approximately 52 miles of 138-kV transmission lines (35 miles from the Big Sandy Station to the Inez Station, and 17 miles from the Inez Station to the Johns Creek Station), and the installation of associated facilities at those stations.

Among the new facilities installed are a new 600-MVA, 345/138-kV transformer at the Big Sandy Station; and, at the Inez Station, a Unified Power Flow Controller (UPFC), a device that incorporates a new technology for controlling power line flows and voltages. The major components of that UPFC device are a ±160-MVAr shunt inverter/static compensator on the Inez Station's 138-kV bus, and a ±160-MVAr series inverter on the Big Sandy-Inez 138-kV line.

It should be noted that, as part of the planning process, AEP and its operating companies continually explore opportunities for improving the efficiency of utilization of their power supply facilities, and actions are taken as appropriate (as, for example, in the case of transmission reinforcement plans). In this regard, opportunities for reductions in system losses is a major consideration in the planning of such facilities. Reduction in these losses represents, in effect, conservation of energy resources on the "utility side" of the meter.

Losses on the AEP/KPCo transmission system have been reduced over time as a result of the development of progressively higher transmission voltage levels, the selection of equipment with lower losses (such as larger sizes of conductors), and modifications to network topology, i.e., transmission-line reconfigurations and additions. Similarly, losses on the distribution system have been reduced as a result of conversions to higher voltage levels, other network modifications, and selection of equipment options with consideration for losses.

D.2. Fuel Adequacy and Procurement

D.2.a. Coal

The generating units of the AEP System, which are predominantly coal-fired, are expected to have adequate fuel supplies to meet normal burn requirements in both the short-term and the long-term. KPCo and the other AEP operating companies attempt to maintain in storage at each plant an adequate coal supply to meet normal burn requirements. However, in situations where coal supplies fall below prescribed minimum levels, AEP System companies have developed programs to conserve coal supplies. These programs involve, on a progressive basis, limitations on sales of power and energy to neighboring utilities, appeals to customers for voluntary limitations of electric usage to essential needs, curtailment of sales to certain industrial customers, voltage reductions and, finally, mandatory reductions of usage of electricity. In the event of a potential severe coal shortage, the AEP System's operating companies, including KPCo, will implement procedures for the orderly reduction of the consumption of electricity, in accordance with the AEP Energy Emergency Control Program, which has been filed with each of the appropriate regulatory authorities, including the Kentucky Public Service Commission.

American Electric Power Energy Services, acting as agent for each of the AEP System's generating companies, is responsible for the overall procurement and delivery of coal to all of the System's generating facilities (as well as to those of Buckeye Power, Inc. and OVEC). The AEP System obtains most of its total coal requirements under long-term arrangements, thus assuring the plants of a relatively stable and consistent supply of coal. The remaining coal requirements are normally satisfied by making short-term and spot-market purchases. Additional spot purchases may occasionally be necessitated by shortfalls in deliveries caused by force majeure and other unforeseeable or unexpected circumstances. Occasionally, spot purchases may also be made to test-burn any promising and potential new long-term sources of coal in order to determine their acceptability as a fuel source in a given power plant's generating units. This policy also provides some flexibility to adjust scheduled contract deliveries for short-term coal supply to accommodate changing demand, which may be more or less than anticipated when the long-term coal requirements were initially projected. During periods preceding the expiration of UMWA contracts, additional fuel is stockpiled at the System's power plants to assure adequate supplies in the event of a prolonged miners' strike.

The System's fuel requirements vary from plant to plant, depending upon such factors as environmental restrictions and boiler design, as well as the demand for electricity. In 1998, coal consumption at AEP-operated plants aggregated to more than 54 million tons. Of this amount, KPCo's Big Sandy plant accounted for about 3 million tons. Historically, the coal supplies for the Big Sandy plant have primarily been provided by coal mines located in Kentucky.

D.2.b. Natural Gas

As indicated in the next section of this chapter and discussed in greater detail in the report titled "AEP System Acid Rain Compliance Report" filed with the Public Utilities Commission of Ohio on April 29, 1992 (and also supplied to the Kentucky Public Service Commission), and updated on October 14, 1994, some of AEP's generating units have been modified in order to become dual-fuel capable as part of the Company's compliance plan. These units would burn natural gas when gas is available and is the economic choice, and would burn coal at other times.

It is anticipated that the site(s) for any new gas-fired capacity that might be added to the AEP System would be determined by analyzing both the AEP System infrastructure capabilities and the availability/proximity of mainline gas transmission pipelines. These pipelines would act as transporters for natural gas which would be purchased from third parties. Through the integrated natural gas transmission network, gas could be sourced from all major production areas, including Appalachia, Canada, Louisiana, Offshore-Gulf of Mexico, Oklahoma, and Texas. It is anticipated that distillate oil would be the backup fuel for any new gas-fired capacity; hence, on-site oil storage would be considered for these potential unit sites.

There exists a very vibrant natural gas spot market with abundant supplies available from geographically diverse regions. The natural gas industry's continued interest in serving electric generation markets, an ongoing expansion of the pipeline system, new gas storage projects, and recent U.S. Department of Energy reports on the adequacy of recoverable natural gas reserves provide a basis to support the future potential natural-gas-fired electric generation on the AEP System.

D.3. Acid Rain Compliance

The AEP System's strategy for continuing to meet the Title IV air emission requirements of the Clean Air Act Amendments of 1990, taking into consideration the inception of Phase II of those requirements in the year 2000, includes the continual evaluation of alternative fuel strategies, opportunities to purchase sulfur dioxide (SO_2) allowances, and possible post-combustion technologies in order to lower the overall cost-impact of compliance. AEP's plan anticipates the continued use of the flue gas desulfurization system (i.e., scrubbers) at Ohio Power's Gavin Plant, the continued use of low-sulfur coal over most of the AEP System, the use of the Phase I accumulated SO_2 allowance bank, and the switching to lower-sulfur fuels when economical.

The U.S. Environmental Protection Agency (EPA) has issued NOx emission limits for Phase II for each boiler-type of generating unit. Units may comply individually with their annual limits or be combined into an averaging plan. The AEP System's Phase II NOx compliance strategy is to install low-NOx burner technologies (or their equivalent) on its units and to utilize an averaging plan for most of the units.

No significant changes in fuel supply are anticipated at this time for the purpose of compliance at KPCo's Big Sandy Plant. Low-NOx burners have already been installed at both of the Plant's units.

E. RESOURCE PLANNING MODELS

Information which describes the planning models (apart from the load forecasting models) utilized by AEP in developing its integrated resource plans is provided below.

E.1. "PROSCREEN" Integrated Resource Planning Model

AEP uses the PROSCREEN II computer software system, leased from Energy Management Associates (EMA), to facilitate analysis of resource expansions and related cost information reflecting integrated resource planning concepts. This computer model, which was developed by EMA to support electric utility decision analysis and corporate planning, includes the following relevant modules:

1. Load Forecast Adjustment (LFA)
2. Generation and Fuel (GAF)
3. Capital Expenditure and Recovery (CER)
4. Financial Reporting and Analysis (FIR)
5. PROVIEW

A brief description of these modules follows.

1. Load Forecast Adjustment (LFA) Module

The function of the LFA module is to provide users with a load data bank to be used in analysis of demand-side strategies and alternatives. Since load data constitute a key information source for PROSCREEN/PROVIEW applications, the user's main task is to create this data from the utility's load research information, load forecast information and other sources as accurately as possible.

The LFA module is flexible enough to process load data information at various levels of detail, depending on data availability. The load shape data may represent a group of customers' load shapes, or may correspond to end uses, rate categories, classes of customers, or even total company. The load shapes present a typical weekly consumption profile for a particular user-defined season. Typical weekly load shapes are constructed from daily load shapes and frequencies of occurrence of the type of day (Monday - Sunday) within the season.

After development of the load data bank, the LFA module develops an aggregate load shape for the total system. This aggregate load shape is passed to other PROSCREEN modules for further analysis. For example, it is used by the Generation and Fuel model to dispatch the generation resources in an optimum manner.

Another key feature of the LFA module is its ability to assess the impact of a demand-side program on the load shapes at various levels. To accomplish this, the user inputs the characteristics of a DSM program, such as impacts on the customer's peak demand and energy use, and market penetration factor. The LFA module uses this information to modify the base load shape and also the future load shapes, according to the projected penetration of participants.

2. **General and Fuel (GAF) Module**
The GAF module simulates power system operation using probabilistic methods, and provides production costs and generation reliability measures. This module requires less computer resources than more detailed production costing models.

The GAF module utilizes load data from the LFA module. The GAF production cost calculation can be performed on an annual or seasonal basis (e.g., quarterly or monthly). In the GAF module, thermal generating units are represented by two capacity segments. Each segment has a distinct heat rate and availability. Multicompany dispatch and interchange accounting is also simulated in the GAF module.

3. **Capital Expenditure and Recovery (CER) Module**
The CER module, through interaction with the GAF and FIR modules, allows analysis of financial implications of an individual project or an entire construction program. The CER module facilitates the examination of financial effects on the company's integrated operation for one or more system generation alternatives.

4. **Financial Reporting and Analysis (FIR) Module**
The FIR module combines the results from the LFA, GAF, and CER modules with additional financial inputs from the planner to produce financial statements and other selected financial information. In addition to the basic financial statements (e.g., income statement, balance sheet and sources and uses of funds), the FIR module produces a rate base report, plant report, financial ratios report, tax report, and rates and regulator lag report. The FIR module, through interaction with the other application models, simulates the financial effects of various construction options, resource plans, inflation scenarios, capital market conditions, and acquisition alternatives.

5. **PROVIEW Module**
The PROVIEW module is an automatic expansion planning program that, through interaction with the GAF and LFA modules, can determine the least-cost balanced supply-and-demand plan for a utility system under a prescribed set of constraints and assumptions. PROVIEW enables planners to study a wide variety of long-range expansion planning issues, such as alternative technologies and DSM, in order to develop a coordinated integrated plan.

The PROVIEW module utilizes a dynamic programming routine, which applies an optimization procedure coupled with end-effects analysis and selects the "best" expansion plan. For each year, feasible combinations of alternatives are evaluated. The plan with the lowest cumulative present-worth cost is selected as the least-cost, or "best," expansion plan.

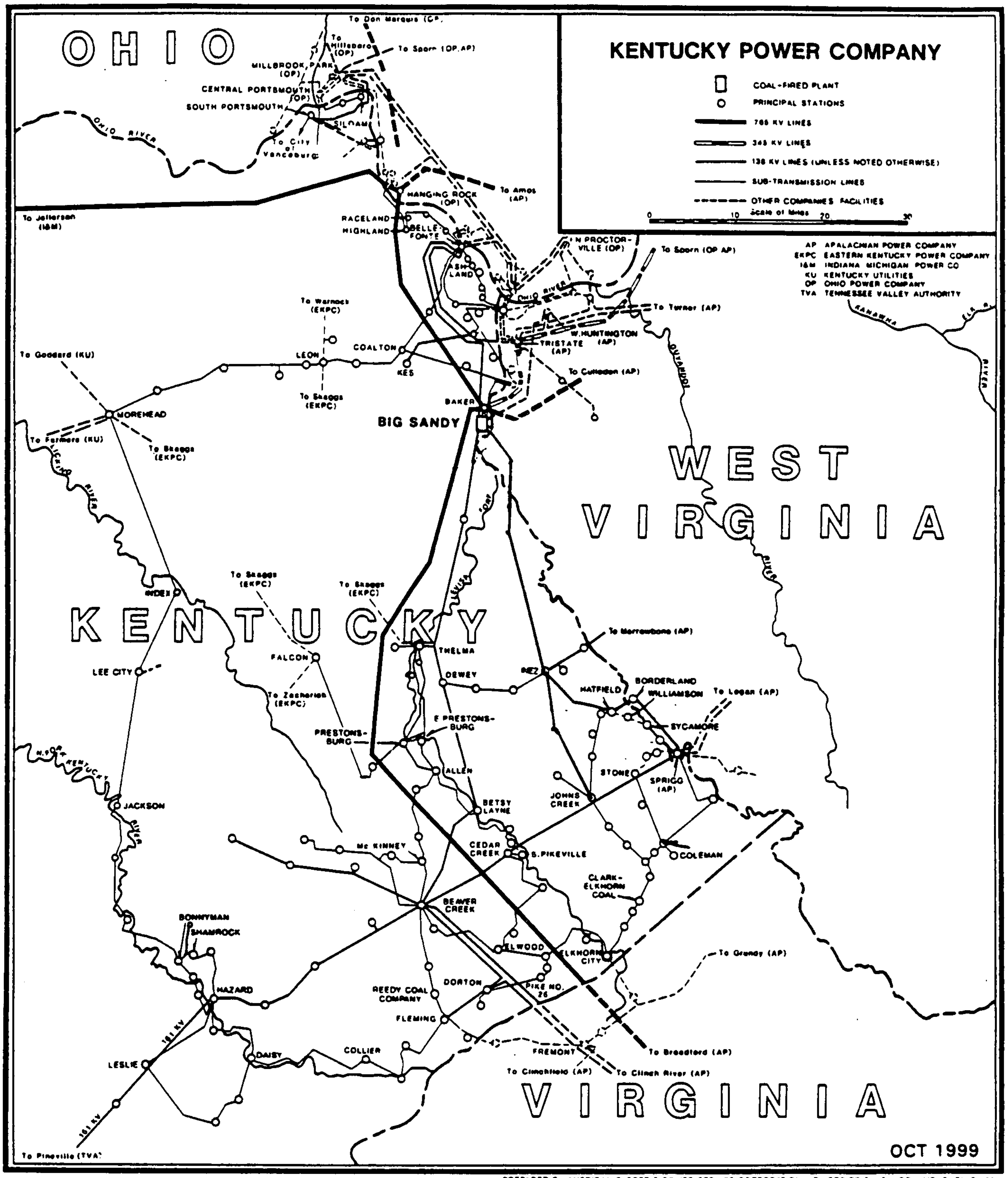
E.2. Capacity Reserve Analysis (CRA) Model

The Capacity Reserve Analysis (CRA) Model program is described in detail in Section B.2.d. of this chapter.

E.3. DSM Screening Model

The DSM screening model used in the screening process for both DSM measures and DSM programs is described in Chapter 3. The model, which was developed in-house, performs various economic calculations, assessing the benefits and costs of each DSM measure or program, based on the Total Resource Cost, Ratepayer Impact Measure, Participant Cost and Utility Cost tests. The software provides the flexibility to incorporate various parameters and input data assumptions for each DSM measure individually, as well as for each DSM program.

Exhibit 4-1



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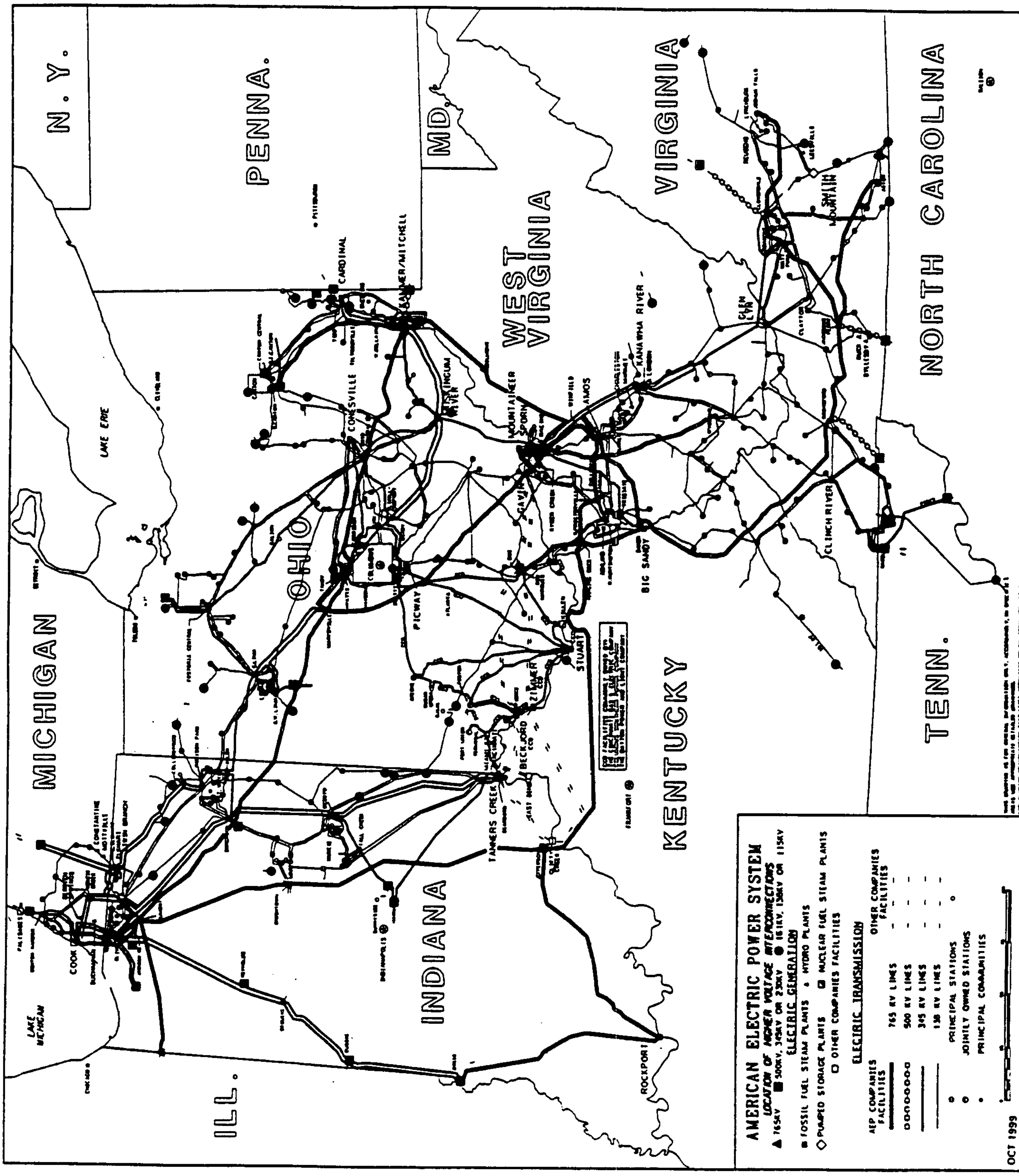

N. Y.
PENNA.
MD.
WEST VIRGINIA
VIRGINIA
NORTH CAROLINA
MICHIGAN
OHIO
INDIANA
KENTUCKY
TENN.
ILL.
LAKE ERIE
LAKE MICHIGAN
CARDINAL
KAMMER/MITCHELL
CONESVILLE
MUSKINGUM RIVER
MOUNTAINEER
SPORN
GAVIN
KANAWHA RIVER
GLEN LYN
SMITH MOUNTAIN
CLINCH RIVER
BIG SANDY
PICWAY
STUART
ZIMMER
BECKJORD
TANNERS CREEK
ROCKPORT
COOK
AMERICAN ELECTRIC POWER SYSTEM
LOCATION OF HIGHER VOLTAGE INTERCONNECTIONS
ELECTRIC GENERATION
FOSSIL FUEL STEAM PLANTS
HYDRO PLANTS
PUMPED STORAGE PLANTS
NUCLEAR FUEL STEAM PLANTS
OTHER COMPANIES FACILITIES
ELECTRIC TRANSMISSION
AEP COMPANIES FACILITIES
OTHER COMPANIES FACILITIES
765 KV LINES
500 KV LINES
345 KV LINES
138 KV LINES
PRINCIPAL STATIONS
JOINTLY OWNED STATIONS
PRINCIPAL COMMUNITIES
OCT 1999

Exhibit 4-3

KENTUCKY POWER COMPANY

AEP SYSTEM INTERCONNECTIONS IN KENTUCKY AREA

FROM	TO	VOLTAGE (KV)	RATINGS (MVA) NORMAL/EMERGENCY SUMMER	WINTER
AEP-CG&E INTERCONNECTIONS				
Tanners Creek (AEP/I&M)*	-- East Bend	345	1195/1315	1195/1315
Tanners Creek (AEP/I&M)*	-- Miami Fort**	345-138	400/440	400/440
Collinsville (AEP/OPC)**	-- Collinsville(CG&E)**	138-69	80/88	80/88
Trenton (AEP/OPC)**	-- Trenton (CG&E)**	138-12	25/25	25/25
Total			1700/1868	1700/1868
AEP-EKPC INTERCONNECTIONS				
Falcon (AEP/KPC)	-- Falcon (EKPC)	46-69	22/25	25/27
Leon (AEP/KPC)	-- Leon (EKPC)	69	39/46	54/54
Thelma (AEP/KPC)	-- Thelma (EKPC)	69	35/35	44/44
Argentum (AEP/KPC)	-- Argentum (EKPC)	69	39/46	54/58
Total			135/152	177/183
AEP-KU INTERCONNECTIONS				
Hillsboro (AEP/OPC)**	-- Kenton	138	164/191	191/191
Morehead (AEP/KPC)	-- Rodburn	69	78/101	103/107
Total			242/292	294/298
AEP-LG&E INTERCONNECTIONS				
Jefferson (AEP/I&M)	-- Clifty Creek*	345	1200/1200	1200/1200
AEP-TVA INTERCONNECTIONS				
Hazard (AEP/KPC)	-- Pineville	161	172/172	196/196

Notes

* Located in Indiana

** Located in Ohio

AEP SYSTEM
CAPACITY RESERVE ANALYSIS

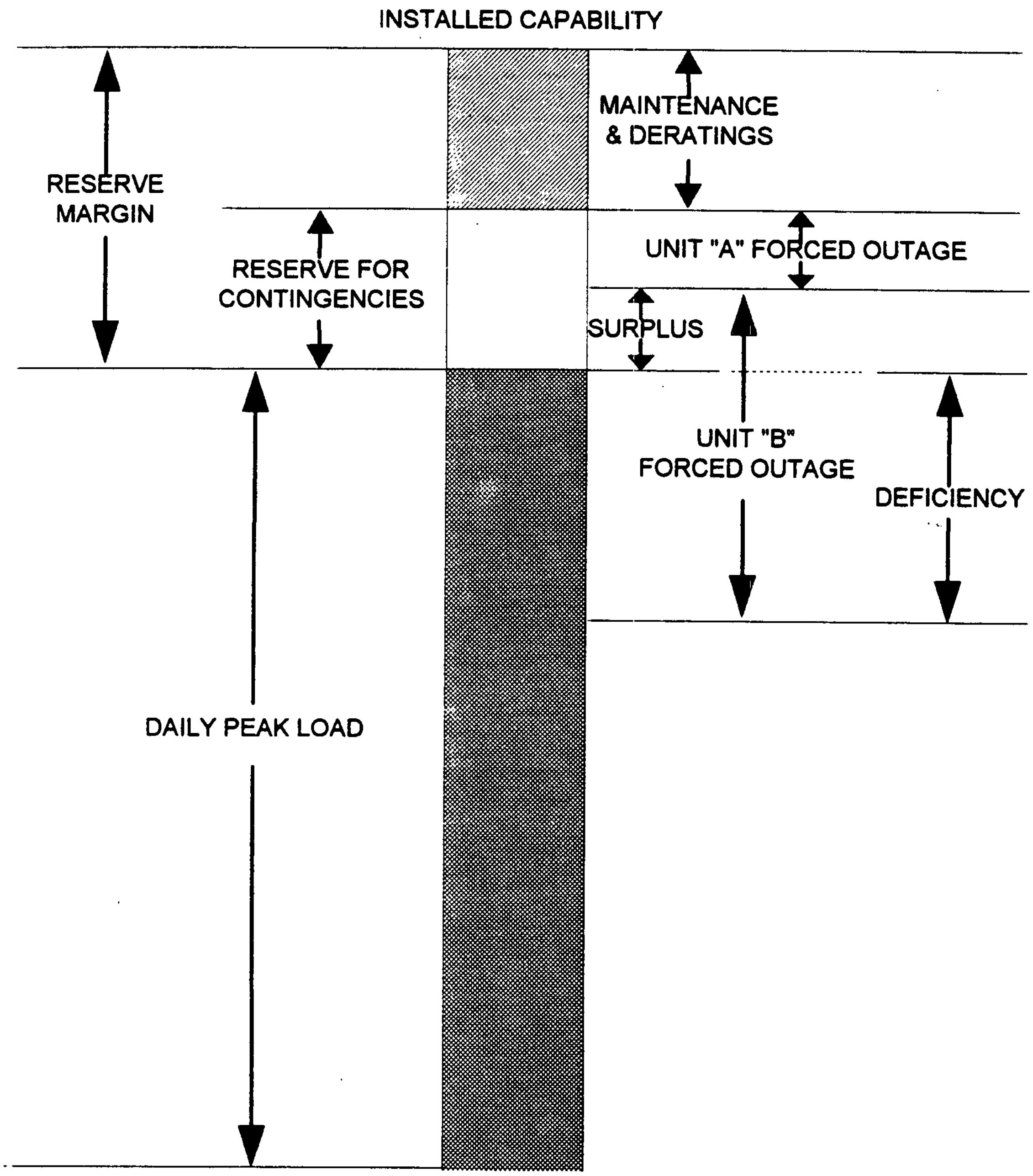
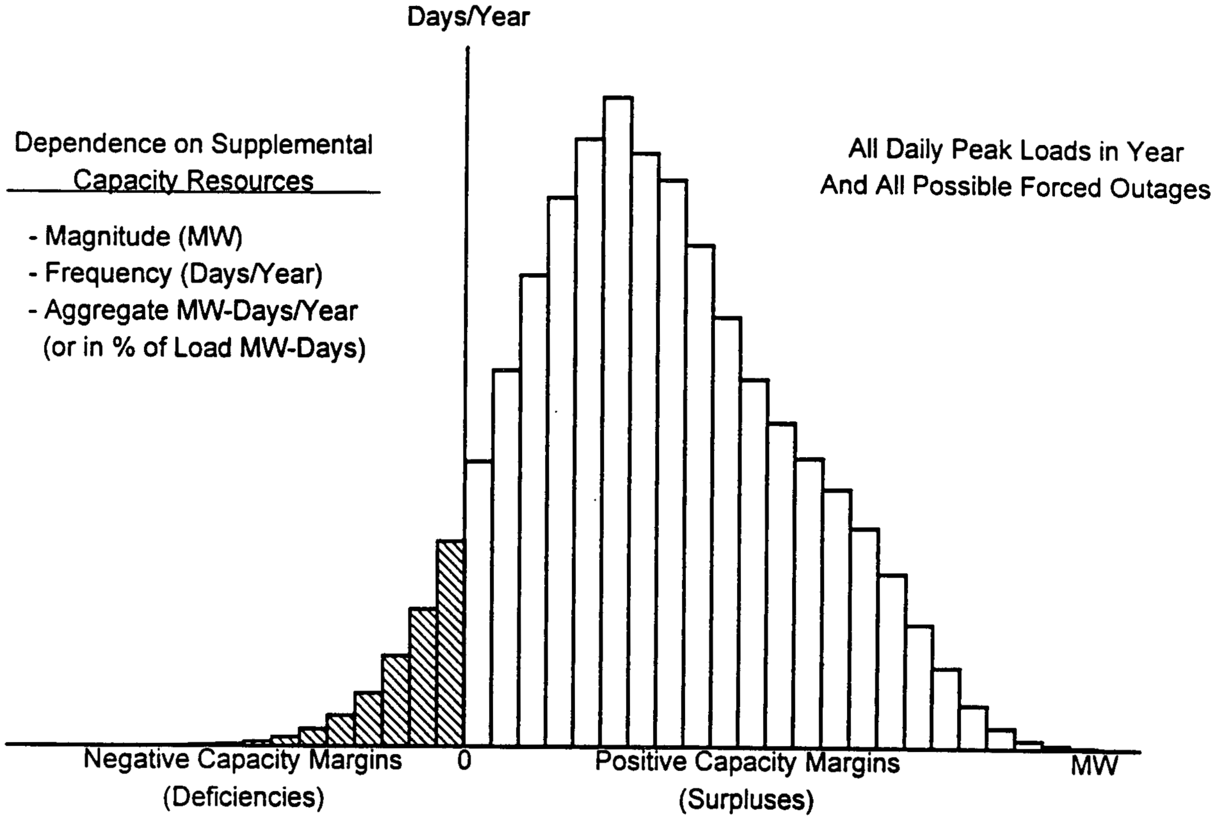


Exhibit 4-5

AEP SYSTEM
DISTRIBUTION OF CAPACITY MARGINS - MW



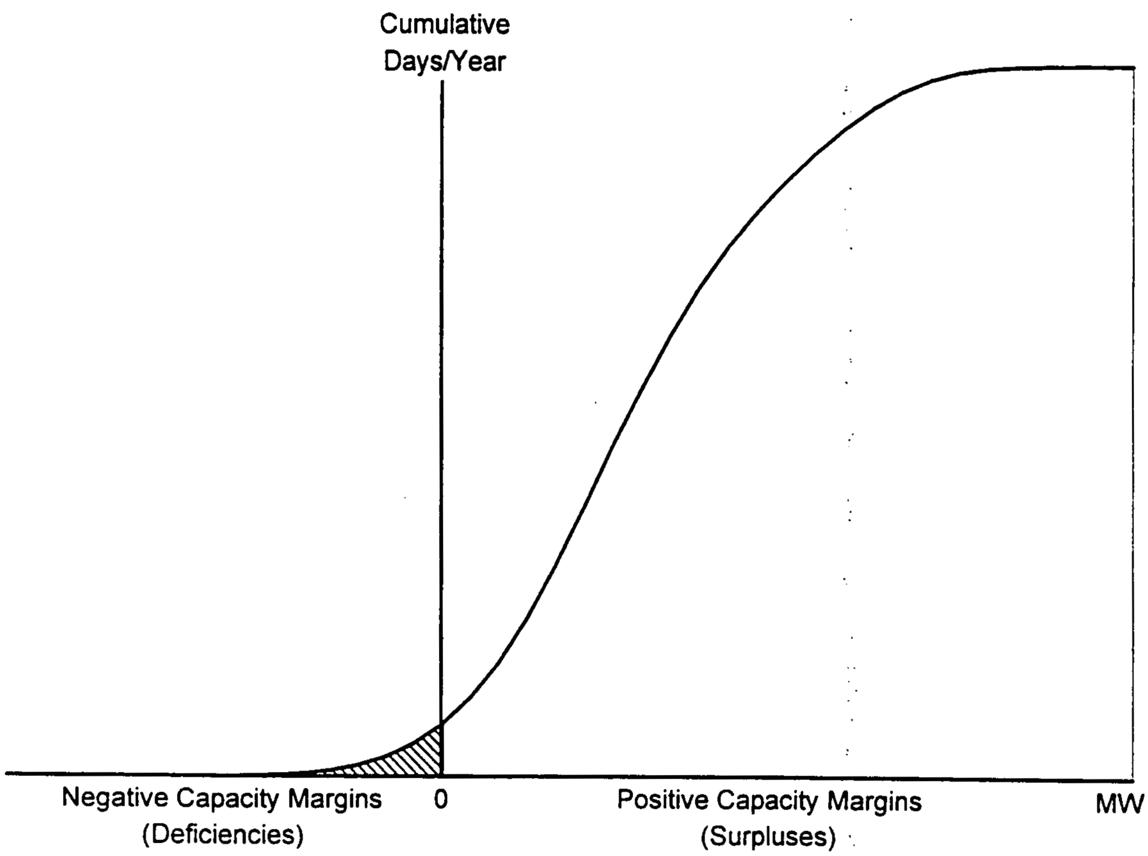


Exhibit 4-6

AEP SYSTEM
Interrelationship of Capacity-Deficient Days, Reserve Margin at Time of Calendar-Year Peak, and Average System On-Peak Equivalent Availability

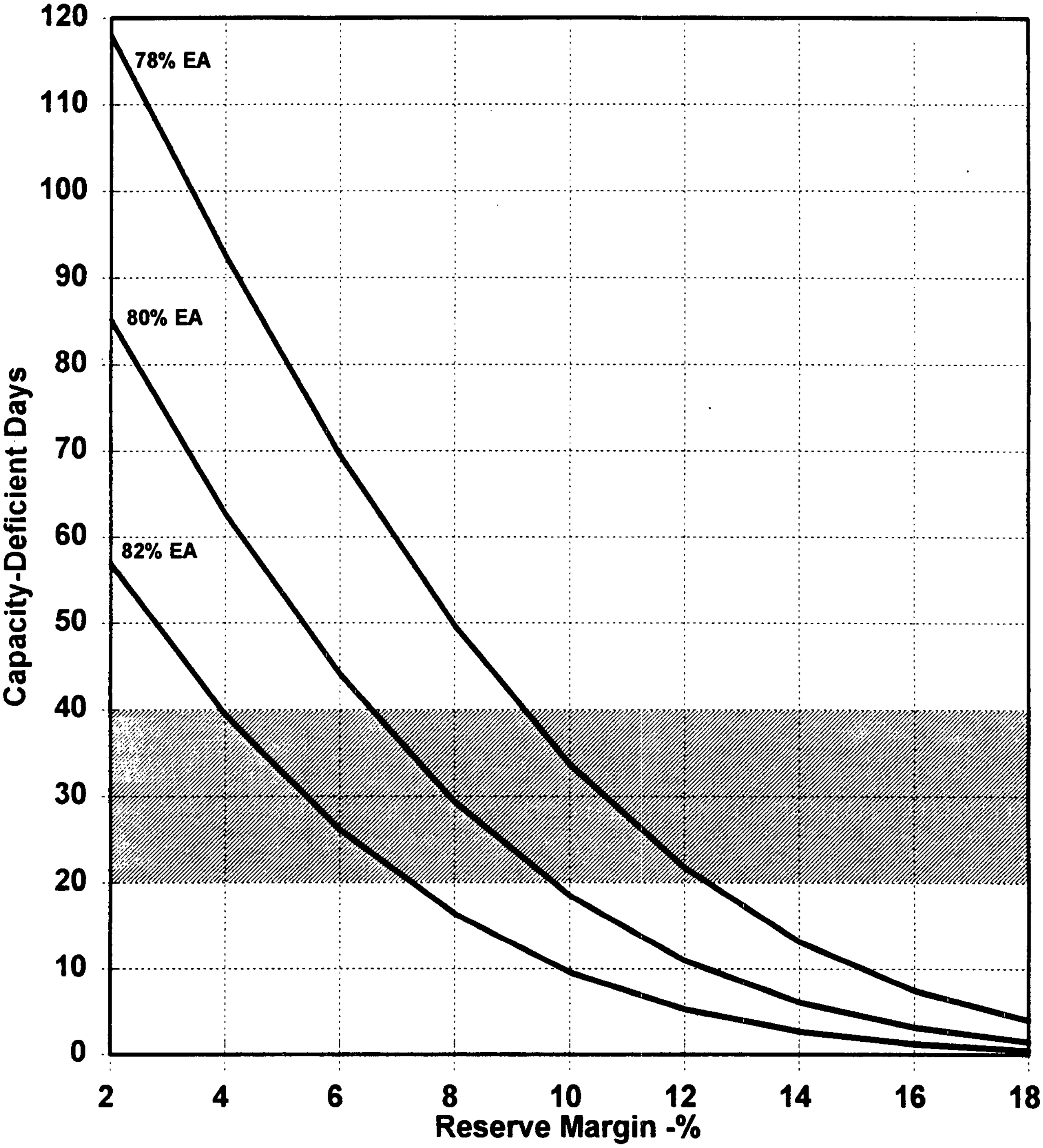
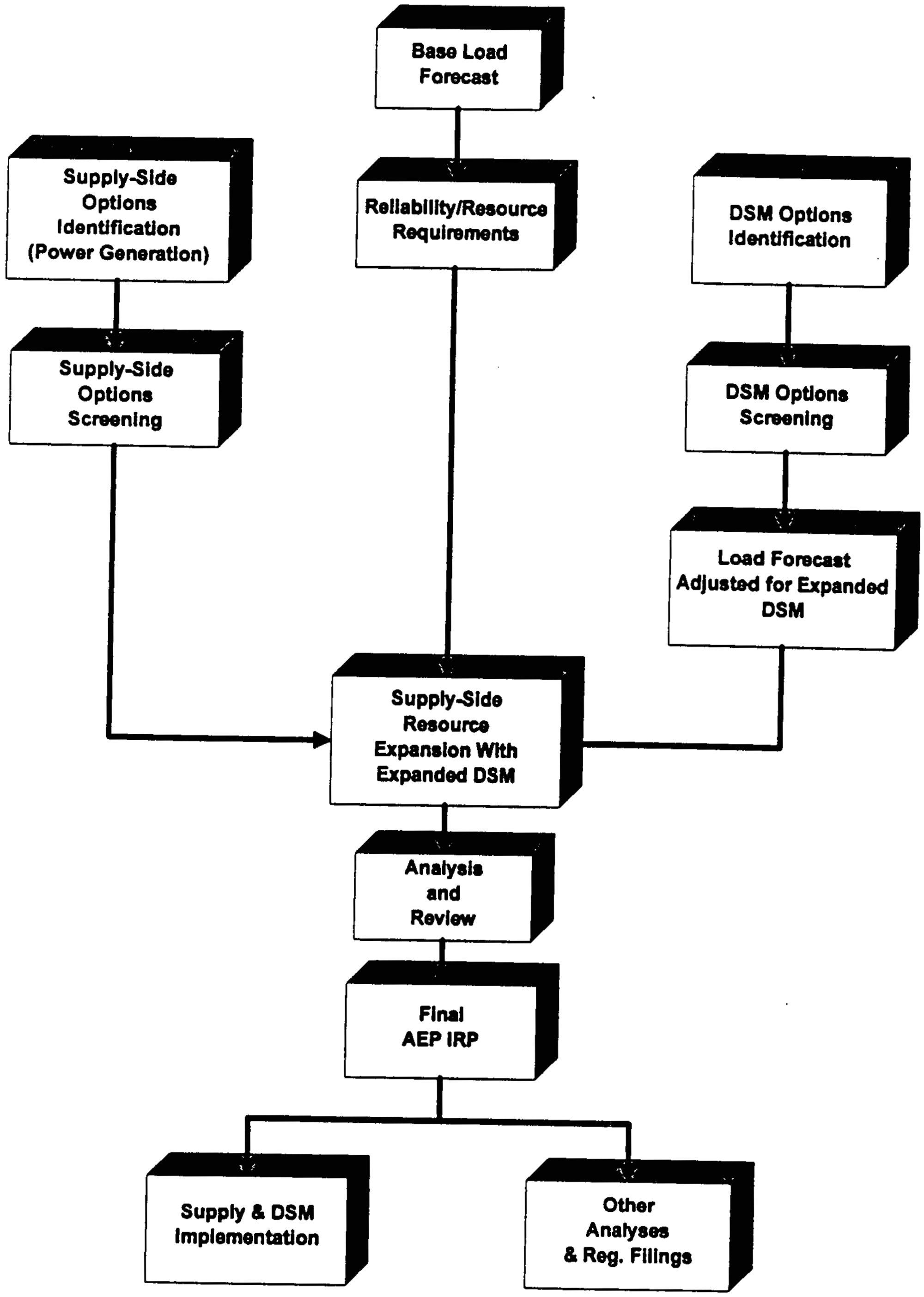


Exhibit 4-7

OVERVIEW OF IRP PROCEDURE



KENTUCKY POWER COMPANY
EXISTING ELECTRIC GENERATING FACILITIES
As of (1/1/99)

Unit	Summer Rating (MW)	Winter Rating (MW)
Big Sandy 1	260	260
Big Sandy 2	800	800
Total Installed Capability	1,060	1,060
Unit Power Purchase	390	390
Total including Purchase	1,450	1,450

Note: Unit power purchase of 390 MW from Rockport plant.
Contract assumed to be terminated on 12/31/04.

AMERICAN ELECTRIC POWER SYSTEM
EXISTING ELECTRIC GENERATING FACILITIES
(as of 1/1/99)

Plant Name	Location	Unit No.	Operation Date	Net Capability Winter (MW)		Net Capability Summer (MW)		Fuel Type	Plant Fuel Storage Capacity (Tons000)	
Fossil-Steam Units										
John E. Amos	St. Albans, WV	1	1971	800		800		Coal	1,750	
		2	1972	800		800		Coal	--	
		3	1973	1,300	(A)	1,300	(A)	Coal	--	
W. C. Beckjord	New Richmond, OH	6	1969	53	(B)	52	(B)	Coal	--	
Big Sandy	Louisa, KY	1	1963	260		260		Coal	1,750	
		2	1969	800		800		Coal	--	
Cardinal (C)	Brilliant, OH	1	1967	600		585		Coal	1,000	(D)
Clinch River	Carbo, VA	1	1958	235		230		Coal	500	
		2	1958	235		230		Coal	--	
		3	1961	235		230		Coal	--	
Conesville	Conesville, OH	1	1959	125		115		Coal	1,100	
		2	1957	125		115		Coal	--	
		3	1962	165		165		Coal	--	
		4	1973	339	(B)	339	(B)	Coal	--	
		5	1976	375		375		Coal	--	
		6	1978	375		375		Coal	--	
Gen.J.M. Gavin	Cheshire, OH	1	1974	1,300		1,300		Coal	2,700	
		2	1975	1,300		1,300		Coal	--	
Glen Lyn	Glen Lyn, VA	5	1944	95		90		Coal	160	
		6	1957	240		235		Coal	--	
Kammer	Captina, WV	1	1958	210		200		Coal	1,050	
		2	1958	210		200		Coal	--	
		3	1959	210		200		Coal	--	
Kanawha River	Glasgow, WV	1	1953	200		195		Coal	300	
		2	1953	200		195		Coal	--	
Mitchell	Captina, WV	1	1971	800		800		Coal	1,650	
		2	1971	800		800		Coal	--	
Mountaineer	New Haven, WV	1	1980	1,300		1,300		Coal	2,100	
Muskingum River	Beverly, OH	1	1953	205		190		Coal	900	(E)
		2	1954	205		190		Coal	--	
		3	1957	215		205		Coal	--	
		4	1958	215		205		Coal	--	
		5	1968	585		575		Coal	--	
Philip Sporn (F)	Graham Station, WV	1	1950	150		145		Coal	750	
		2	1950	150		145		Coal	--	
		3	1951	150		145		Coal	--	
		4	1952	150		145		Coal	--	
		5	1960	450		440		Coal	--	
Picway	Lockbourne, OH	5	1955	100		90		Coal	250	
Rockport	Rockport, IN	1	1984	1,300	(G)	1,300	(G)	Coal	2,500	(H)
		2	1989	1,300	(G)	1,300	(G)	Coal	--	
J. M. Stuart	Aberdeen, OH	1	1971	152	(B)	152	(B)	Coal	--	
		2	1970	152	(B)	152	(B)	Coal	--	
		3	1972	152	(B)	152	(B)	Coal	--	
		4	1974	152	(B)	152	(B)	Coal	--	
Tanners Creek	Lawrenceburg, IN	1	1951	145		140		Coal	400	
		2	1952	145		140		Coal	--	
		3	1954	205		200		Coal	--	
		4	1964	500		500		Coal	--	
Zimmer	Moscow, OH	1	1991	330	(B)	330	(B)	Coal	--	
	Total Fossil-Steam			20,795		20,579				

AMERICAN ELECTRIC POWER SYSTEM
EXISTING ELECTRIC GENERATING FACILITIES
(as of 1/1/99)

Plant Name	Location	Unit No.	Operation Date	Net Capability Winter (MW)	Net Capability Summer (MW)	Fuel Type	Plant Fuel Storage Capacity (Tons000)
Nuclear-Steam Units							
Cook Nuclear	Bridgman, MI	1	1975	1,020	1,000	Uran.	--
		2	1978	1,090	1,060	Uran.	--
	Total Nuclear-Steam			2,110	2,060		
Conventional Hydro Units							
Berrien Springs	Berrien Springs, IN	1,3,4	1908	3 (I)	-- (J)	--	--
		2	1918	--	-- (J)	--	--
Buchanan	Buchanan, MI	1,2	1919	2 (I)	-- (J)	--	--
		3-6	1920	--	-- (J)	--	--
		7-10	1927	--	-- (J)	--	--
Buck	Ivanhoe, VA	1-3	1912	10	-- (J)	--	--
Byllesby	Byllesby, VA	1-4	1912	20	-- (J)	--	--
Claytor	Radford, VA	1-4	1939	76	-- (J)	--	--
Constantine	Constantine, MI	1,4	1923	1 (I)	-- (J)	--	--
		2,3	1921	--	-- (J)	--	--
Elkhart	Elkhart, IN	1	1921	1 (I)	-- (J)	--	--
		2,3	1913	--	-- (J)	--	--
Leesville	Leesville, VA	1	1964	20	-- (J)	--	--
		2	1964	20	-- (J)	--	--
London	Montgomery, WV	1-3	1935	16	-- (J)	--	--
Marmet	Marmet, WV	1-3	1935	16	-- (J)	--	--
Mottville	Mottville, MI	1-4	1923	1	-- (J)	--	--
Niagara	Roanoke, VA	1	1954	3 (I)	-- (J)	--	--
		2	1954	--	-- (J)	--	--
Racine	Racine, OH	1	1983	24	24	--	--
		2	1982	24	24	--	--
Reusens	Lynchburg, VA	1-5	1903	12	-- (J)	--	--
Twin Branch	Mishawaka, IN	1,6	1989 (K)	3 (I)	-- (J)	--	--
		2-5	1992 (K)	--	-- (J)	--	--
Winfield	Winfield, WV	1-3	1938	19	-- (J)	--	--
	Total Conventional Hydro			271	234		
Pumped Storage Hydro Units							
Smith Mountain	Penhook, VA	1	1965	70	70	--	--
		2	1965	160	160	--	--
		3	1980	105	105	--	--
		4	1966	160	160	--	--
		5	1966	70	70	--	--
	Total Pumped Storage Hydro			565	565		
Combustion Turbine Units							
Fourth Street	Fort Wayne, IN	1	1970	18 (L)	15 (L)	Oil	--
			Total Before Adjustments	23,759	23,453		
			Unit Power Sale Adjustment (M)	705	705		
			Total After Adjustments	23,054	22,748		
Cardinal (C)	Brilliant, OH	2	1967	600	585	Coal	
		3	1977	630	630	Coal	
			Total Including Buckeye Power	24,284	23,963		

AMERICAN ELECTRIC POWER SYSTEM
EXISTING ELECTRIC GENERATING FACILITIES
(as of 1/1/99)

Notes: (A) Ohio Power owns two-thirds (867 MW), and Appalachian Power owns one-third (433 MW), of Unit 3.

(B) Columbus Southern Power's share of unit, jointly owned with Cincinnati Gas & Electric Co. and Dayton Power and Light Co.

Unit(s)	% Owned by AEP
Beckjord 6	12.5
Conesville 4	43.5
Stuart 1-4	26.0
Zimmer	25.4

(C) The Cardinal Plant consists of three coal-fired steam units, with Unit No. 1 owned by Ohio Power Company and Unit Nos. 2 and 3 owned by Buckeye Power, Inc.

(D) Includes storage capacity associated with Cardinal Units 2 and 3, owned by Buckeye Power, Inc.

(E) Additional storage capacity of 1,100 thousand tons is available at Muskingum Mine site.

(F) The Philip Sporn Plant is jointly owned by Ohio Power Company and Appalachian Power Company.

(G) Unit 1 of the Rockport Plant is owned one-half by AEP Generating Company (AEG) and one-half by I&M. Unit 2 is leased one-half by AEG and one-half by I&M. The leases commenced in 1989 and terminate in 2022 unless extended. Unit power agreements between AEG and I&M provide for the purchase by I&M of 910 MW from AEG's 1,300-MW share in the Rockport plant. However, effective January 1, 1987, I&M's 455-MW allocation of Rockport Unit 1 was assigned to the Unit Power sale to VEPCo through December 31, 1999. Also, effective January 1, 1990, 250 MW of I&M's leased share of Rockport Unit 2 was allocated to the Unit Power sale to CP&L through December 31, 2009.

(H) Additional storage capacity of 150 thousand tons is available at Cook Terminal.

(I) Plant total.

(J) Summer net capability values are not available on an individual plant basis for this conventional hydro plant.

(K) Twin Branch Hydro Plant was originally constructed from 1904 - 1922. New turbine/generators were placed in service in 1989 and 1992.

(L) Leased from City of Ft. Wayne.

(M) Reflects the following unit power sales from Rockport: 455-MW sale to VEPCo through 12/31/99 and 250-MW sale to CP&L through 12/31/04

AMERICAN ELECTRIC POWER SYSTEM
STEAM GENERATING-CAPACITY PRODUCTION COST AND OPERATING INFORMATION
1998

	PLANT COST DATA					UNIT OPERATING DATA			
Plant Name	Average Fuel Cost (¢/MBtu)	Non-Fuel Variable O&M ($000)	Fixed O&M ($000)	Average Variable Production Cost (¢/kWh)	Average Total Production Cost (¢/kWh)	Unit Number	Capacity Factor (%)	Equivalent Availability Factor (%)	Average Heat Rate (Btu/kWh)
Amos	146.41	10,858	30,666	15.05	17.04	1	72.1	89.0	9,587
						2	66.1	81.3	9,412
						3	50.7	63.6	10,055
Beckjord	118.53	198	484	12.79	14.4	6	64.8	85.6	10,208
Big Sandy	112.15	5,916	14,777	11.38	13.25	1	73.2	77.7	9,608
						2	88.8	96.5	9,400
Cardinal	191.38	3,500	6,517	19.40	20.89	1	58.4	77.3	9,458
Clinch	126.07	4,421	11,379	12.64	14.98	1	70.5	79.1	9,307
						2	82.7	91.2	9,313
						3	83.2	91.2	9,241
Conesville	145.29	9,660	28,597	16.50	20.06	1	52.5	75.1	11,698
						2	58.2	82.3	11,088
						3	53.3	95.2	10,172
						4	44.0	67.3	10,187
						5	71.7	91.0	10,362
						6	72.4	90.3	10,280
Cook	na	44,206	194,860	na	na	1	0.0	0.0	0
						2	0.0	0.0	0
Gavin	177.41	13,622	117,408	18.12	25.28	1	64.5	73.2	9,652
						2	79.5	89.1	9,777
Glen Lyn	135.18	2,291	7,878	15.12	19.26	5	50.2	80.9	12,703
						6	70.8	90.3	9,437
Kammer	93.42	6,068	13,457	10.74	14.1	1	74.5	78.3	9,961
						2	69.5	72.8	9,821
						3	73.7	77.3	9,742

AMERICAN ELECTRIC POWER SYSTEM
STEAM GENERATING-CAPACITY PRODUCTION COST AND OPERATING INFORMATION
1998

	PLANT COST DATA					UNIT OPERATING DATA			
Plant Name	Average Fuel Cost (¢/MBtu)	Non-Fuel Variable O&M ($000)	Fixed O&M ($000)	Average Variable Production Cost (¢/kWh)	Average Total Production Cost (¢/kWh)	Unit Number	Capacity Factor (%)	Equivalent Availability Factor (%)	Average Heat Rate (Btu/kWh)
Kanawha	139.10	2,196	7,174	14.54	17.34	1	72.7	88.7	9,720
						2	73.2	89.7	9,900
Mitchell	144.74	5,034	12,466	14.38	15.66	1	66.6	86.7	9,586
						2	72.2	93.0	9,486
Mountaineer	148.41	7,998	16,087	14.81	16.88	1	68.1	88.3	9,225
Muskingum	219.58	8,291	22,780	23.01	26.17	1	54.4	82.1	10,390
						2	55.7	80.0	10,308
						3	60.6	88.6	9,909
						4	58.9	85.6	9,988
						5	58.1	68.2	9,641
Picway	107.64	1,108	3,209	15.67	24.52	5	41.4	75.5	11,505
Rockport	112.18	11,879	162,292	11.78	21.06	1	79.6	87.1	9,972
						2	74.0	79.9	9,722
Sporn	128.08	7,310	20,511	13.34	16.35	1	75.4	91.5	10,007
						2	64.9	83.0	9,936
						3	75.6	91.0	9,442
						4	57.5	72.7	9,795
						5	81.8	87.9	9,203
Stuart	130.45	3,815	6,928	13.36	15.2	1	71.8	83.5	9,440
						2	80.5	90.6	9,452
						3	67.7	77.5	9,383
						4	63.5	75.7	9,502
Tanners	129.26	10,500	21,514	15.37	19.99	1	55.2	78.1	10,537
						2	54.2	78.7	10,336
	129.18					3	68.6	91.3	10,014
						4	46.7	54.1	9,901
Zimmer	106.76	1,460	8,768	11.10	14.74	1	83.3	89.8	9,756

Exhibit 4-11

AEP SYSTEM
1999 IRP Studies
Assumed Base Capacity Changes
(1999 - 2019)

Unit	Net Capability - MW Winter	Net Capability - MW Summer	Type	Effective Date
Smith Mountain	36	36	Rerate	01/01/00
Rockport 1	455	455	Return of Capacity	01/01/00
Summersville Hydro	25	17	QF Purchase	01/01/01
Kammer 1-3*	(630)	(600)	Retirement	12/31/08
Muskingum River 1-4*	(840)	(790)	Retirement	12/31/08
Rockport 2	250	250	Return of Capacity	01/01/10
Sporn 1-4**	(600)	(580)	Retirement	12/31/10
Cardinal 2-3 (Buckeye)	(1,230)	(1,215)	Contract Termination	09/20/12
Conesville 1-3*	(415)	(395)	Retirement	12/31/12
Kanawha River 1-2**	(400)	(390)	Retirement	12/31/13
Glen Lyn 5***	(95)	(90)	Retirement	12/31/14
Tanners Creek 1-3**	(495)	(480)	Retirement	12/31/14
Tanners Creek 4*	(500)	(500)	Retirement	12/31/14
Picway 5**	(100)	(90)	Retirement	12/31/15
Glen Lyn 6**	(240)	(235)	Retirement	12/31/17

Notes: * Based on 50-year life expectancy.
** Based on 60-year life expectancy.
*** Based on 70-year life expectancy.

AEP SYSTEM
Currently Committed Power Transactions with Other Utilities

Title	Beginning	Ending	Amount of Sale (or Purchase)	Designated Unit, If Unit Power Sale	Comments
Unit Power Sale to Virginia Electric and Power Company (VEPCo)	Jan. 1, 1987	Dec. 31, 1999	455 MW	Rockport 1	I&M and AEP Generating Co. (AEG) co-own Rockport Unit 1
Supplemental Power Sale to VEPCo	Jan. 1, 1987	Dec. 31, 1999	45 MW		
Unit Power Sale to Carolina Power & Light Company (CP&L)	Jan. 1, 1990	Dec. 31, 2009	250 MW	Rockport 2	I&M and AEG co-lease Rockport Unit 2
Unit Power Sales to Kentucky Power Company (KPCo)	Dec.10, 1984	Dec. 31, 2004	195 MW	Rockport 1	Agreements expire 12/31/99; Assume extension until 12/31/04.
	Dec.1,1989	Dec. 31, 2004	195 MW	Rockport 2	
Firm Power Sale to Richmond Power & Light Company (RP&L)	Jan 1, 1999	Dec. 31, 1999	8 MW		Sale assigned to I&M.
	Jan 1, 2000	Dec. 31, 2000	13 MW		
Base Load Power Sale to North Carolina Electric Membership Corporation (NCEMC)	Jan. 1, 1996	Dec. 31, 2010	205 MW		
Purchase from Summersville Hydro, a PURPA Qualifying Facility	Jan. 1, 2001	-	(25/17 MW)		Purchase Assigned to APCo. Winter: 25 MW; Summer: 17 MW

Exhibit 4-13
(Page 1 of 2)

AMERICAN ELECTRIC POWER SYSTEM
(Including Buckeye Power)

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2000 - 2019
Without Expanded DSM and New Resource Additions

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DEMAND											
1. Base Peak Internal Demand		19,727	20,060	20,407	20,757	21,088	21,419	21,750	22,080	22,411	22,742
2. Expanded DSM Programs		-	-	-	-	-	-	-	-	-	-
3. Adjusted Peak Internal Demand		19,727	20,060	20,407	20,757	21,088	21,419	21,750	22,080	22,411	22,742
4 Committed Capacity Sales (A)											
Richmond Power & Light (Firm)		13	-	-	-	-	-	-	-	-	-
NCEMC (Base-load Power)		205	205	205	205	205	205	205	205	205	205
Total		218	205	205	205	205	205	205	205	205	205
5 Total AEP Peak Demand		19,945	20,265	20,612	20,962	21,293	21,624	21,955	22,285	22,616	22,947
6 Buckeye Power Peak Demand		1,160	1,208	1,238	1,269	1,298	1,331	1,360	1,392	1,067	1,067
7 AEP + Buckeye Peak Demand		21,105	21,473	21,850	22,231	22,591	22,955	23,315	23,677	23,683	24,014
8 Interruptible Load		(674)	(674)	(674)	(674)	(674)	(674)	(674)	(674)	(674)	(674)
9. AEP + Buckeye Peak Demand Excluding Interruptible Load		20,431	20,799	21,176	21,557	21,917	22,281	22,641	23,003	23,009	23,340
GENERATING CAPABILITY (Seasonal)											
10. Capacity Before Changes											
AEP		23,453	23,489	23,489	23,489	23,489	23,489	23,489	23,489	23,489	23,489
Buckeye		1,215	1,215	1,215	1,215	1,215	1,215	1,215	1,215	1,215	1,215
Total		24,668	24,704	24,704	24,704	24,704	24,704	24,704	24,704	24,704	24,704
11. Capacity Changes											
Additions		-	-	-	-	-	-	-	-	-	-
Retirements		-	-	-	-	-	-	-	-	-	(1,390)
Rerates		36	-	-	-	-	-	-	-	-	-
Total		36	-	-	-	-	-	-	-	-	(1,390)
12 Capacity After Changes		24,704	24,704	24,704	24,704	24,704	24,704	24,704	24,704	24,704	23,314
13 Unit Power Sales - CP&L		(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)
14 Net Capacity		24,454	24,454	24,454	24,454	24,454	24,454	24,454	24,454	24,454	23,064
15 Firm Purchases - Non-Utility Generators		-	17	17	17	17	17	17	17	17	17
16 Total Capability		24,454	24,471	24,471	24,471	24,471	24,471	24,471	24,471	24,471	23,081
RESERVE MARGIN											
Based on Including Interruptible Load											
17 MW	(16)-(7)	3,349	2,998	2,621	2,240	1,880	1,516	1,156	794	788	(933)
18 Percent of Demand	[(17)/(7)]x100	15.9	14.0	12.0	10.1	8.3	6.6	5.0	3.4	3.3	(3.9)
Based on Excluding Interruptible Load											
19 MW	(16)-(9)	4,023	3,672	3,295	2,914	2,554	2,190	1,830	1,468	1,462	(259)
20 Percent of Demand	[(19)/(9)]x100	19.7	17.7	15.6	13.5	11.7	9.8	8.1	6.4	6.4	(1.1)

Note: (A) Excluding Unit Power Sales.

Exhibit 4-13
(Page 2 of 2)

AMERICAN ELECTRIC POWER SYSTEM
(Including Buckeye Power)

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2000 - 2019
Without Expanded DSM and New Resource Additions

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
DEMAND											
1. Base Peak Internal Demand		23,073	23,403	23,734	24,065	24,395	24,726	25,057	25,388	25,718	26,049
2. Expanded DSM Programs		-	-	-	-	-	-	-	-	-	-
3. Adjusted Peak Internal Demand		23,073	23,403	23,734	24,065	24,395	24,726	25,057	25,388	25,718	26,049
4 Committed Capacity Sales (A)											
Richmond Power & Light (Firm)		-	-	-	-	-	-	-	-	-	-
NCEMC (Base-load Power)		205	-	-	-	-	-	-	-	-	-
Total		205	-	-	-	-	-	-	-	-	-
5 Total AEP Peak Demand		23,278	23,403	23,734	24,065	24,395	24,726	25,057	25,388	25,718	26,049
6 Buckeye Power Peak Demand		1,067	1,067	1,067	-	-	-	-	-	-	-
7 AEP + Buckeye Peak Demand		24,345	24,470	24,801	24,065	24,395	24,726	25,057	25,388	25,718	26,049
8 Interruptible Load		(674)	(674)	(674)	(674)	(674)	(674)	(674)	(674)	(674)	(674)
9. AEP + Buckeye Peak Demand Excluding Interruptible Load		23,671	23,796	24,127	23,391	23,721	24,052	24,383	24,714	25,044	25,375
GENERATING CAPABILITY (Seasonal)											
10. Capacity Before Changes											
AEP		22,099	22,099	21,519	21,519	21,124	20,734	19,664	19,574	19,574	19,339
Buckeye		1,215	1,215	1,215	-	-	-	-	-	-	-
Total		23,314	23,314	22,734	21,519	21,124	20,734	19,664	19,574	19,574	19,339
11. Capacity Changes											
Additions		-	-	-	-	-	-	-	-	-	-
Retirements		-	(580)	-	(395)	(390)	(1,070)	(90)	-	(235)	-
Rerates		-	-	-	-	-	-	-	-	-	-
Total		-	(580)	-	(395)	(390)	(1,070)	(90)	-	(235)	-
12 Capacity After Changes		23,314	22,734	22,734	21,124	20,734	19,664	19,574	19,574	19,339	19,339
13 Unit Power Sale - CP&L		-	-	-	-	-	-	-	-	-	-
14 Net Capacity		23,314	22,734	22,734	21,124	20,734	19,664	19,574	19,574	19,339	19,339
15 Firm Purchases - Non-Utility Generators		17	17	17	17	17	17	17	17	17	17
16 Total Capability		23,331	22,751	22,751	21,141	20,751	19,681	19,591	19,591	19,356	19,356
RESERVE MARGIN											
Based on Including Interruptible Load											
17 MW	(16)-(7)	(1,014)	(1,719)	(2,050)	(2,924)	(3,644)	(5,045)	(5,466)	(5,797)	(6,362)	(6,693)
18 Percent of Demand	[(17)/(7)]x100	(4.2)	(7.0)	(8.3)	(12.2)	(14.9)	(20.4)	(21.8)	(22.8)	(24.7)	(25.7)
Based on Excluding Interruptible Load											
19 MW	(16)-(9)	(340)	(1,045)	(1,376)	(2,250)	(2,970)	(4,371)	(4,792)	(5,123)	(5,688)	(6,019)
20 Percent of Demand	[(19)/(9)]x100	(1.4)	(4.4)	(5.7)	(9.6)	(12.5)	(18.2)	(19.7)	(20.7)	(22.7)	(23.7)

Note: (A) Excluding Unit Power Sales.

AMERICAN ELECTRIC POWER SYSTEM
(Including Buckeye Power)

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
1999/00 - 2018/19
Without Expanded DSM and New Resource Additions

	1999/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09
DEMAND										
1. Base Peak Internal Demand	19,082	19,372	19,660	19,955	20,244	20,533	20,821	21,110	21,399	21,687
2. Expanded DSM Programs	-	-	-	-	-	-	-	-	-	-
3. Adjusted Peak Internal Demand	19,082	19,372	19,660	19,955	20,244	20,533	20,821	21,110	21,399	21,687
4 Committed Capacity Sales (A)										
Richmond Power & Light (Firm)	13	-	-	-	-	-	-	-	-	-
NCEMC (Base-load Power)	205	205	205	205	205	205	205	205	205	205
Total	218	205	205	205	205	205	205	205	205	205
5 Total AEP Peak Demand	19,300	19,577	19,865	20,160	20,449	20,738	21,026	21,315	21,604	21,892
6 Buckeye Power Peak Demand	1,177	1,228	1,258	1,289	1,319	1,351	1,380	1,412	1,067	1,067
7 AEP + Buckeye Peak Demand	20,477	20,805	21,123	21,449	21,768	22,089	22,406	22,727	22,671	22,959
8 Interruptible Load	(681)	(681)	(681)	(681)	(681)	(681)	(681)	(681)	(681)	(681)
9. AEP + Buckeye Peak Demand Excluding Interruptible Load	19,796	20,124	20,442	20,768	21,087	21,408	21,725	22,046	21,990	22,278
GENERATING CAPABILITY (Seasonal)										
10. Capacity Before Changes										
AEP	23,759	23,795	23,795	23,795	23,795	23,795	23,795	23,795	23,795	23,795
Buckeye	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230
Total	24,989	25,025	25,025	25,025	25,025	25,025	25,025	25,025	25,025	25,025
11. Capacity Changes										
Additions	-	-	-	-	-	-	-	-	-	-
Retirements	-	-	-	-	-	-	-	-	-	(1,470)
Rerates	36	-	-	-	-	-	-	-	-	-
Total	36	-	-	-	-	-	-	-	-	(1,470)
12 Capacity After Changes	25,025	25,025	25,025	25,025	25,025	25,025	25,025	25,025	25,025	23,555
13 Unit Power Sale - CP&L	(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)
14 Net Capacity	24,775	24,775	24,775	24,775	24,775	24,775	24,775	24,775	24,775	23,305
15 Firm Purchases - Non-Utility Generators	-	25	25	25	25	25	25	25	25	25
16 Total Capability	24,775	24,800	24,800	24,800	24,800	24,800	24,800	24,800	24,800	23,330
RESERVE MARGIN										
Based on Including Interruptible Load										
17 MW (16)-(7)	4,298	3,995	3,677	3,351	3,032	2,711	2,394	2,073	2,129	371
18 Percent of Demand [(17)/(7)]x100	21.0	19.2	17.4	15.6	13.9	12.3	10.7	9.1	9.4	1.6
Based on Excluding Interruptible Load										
19 MW (16)-(9)	4,979	4,676	4,358	4,032	3,713	3,392	3,075	2,754	2,810	1,052
20 Percent of Demand [(19)/(9)]x100	25.2	23.2	21.3	19.4	17.6	15.8	14.2	12.5	12.8	4.7

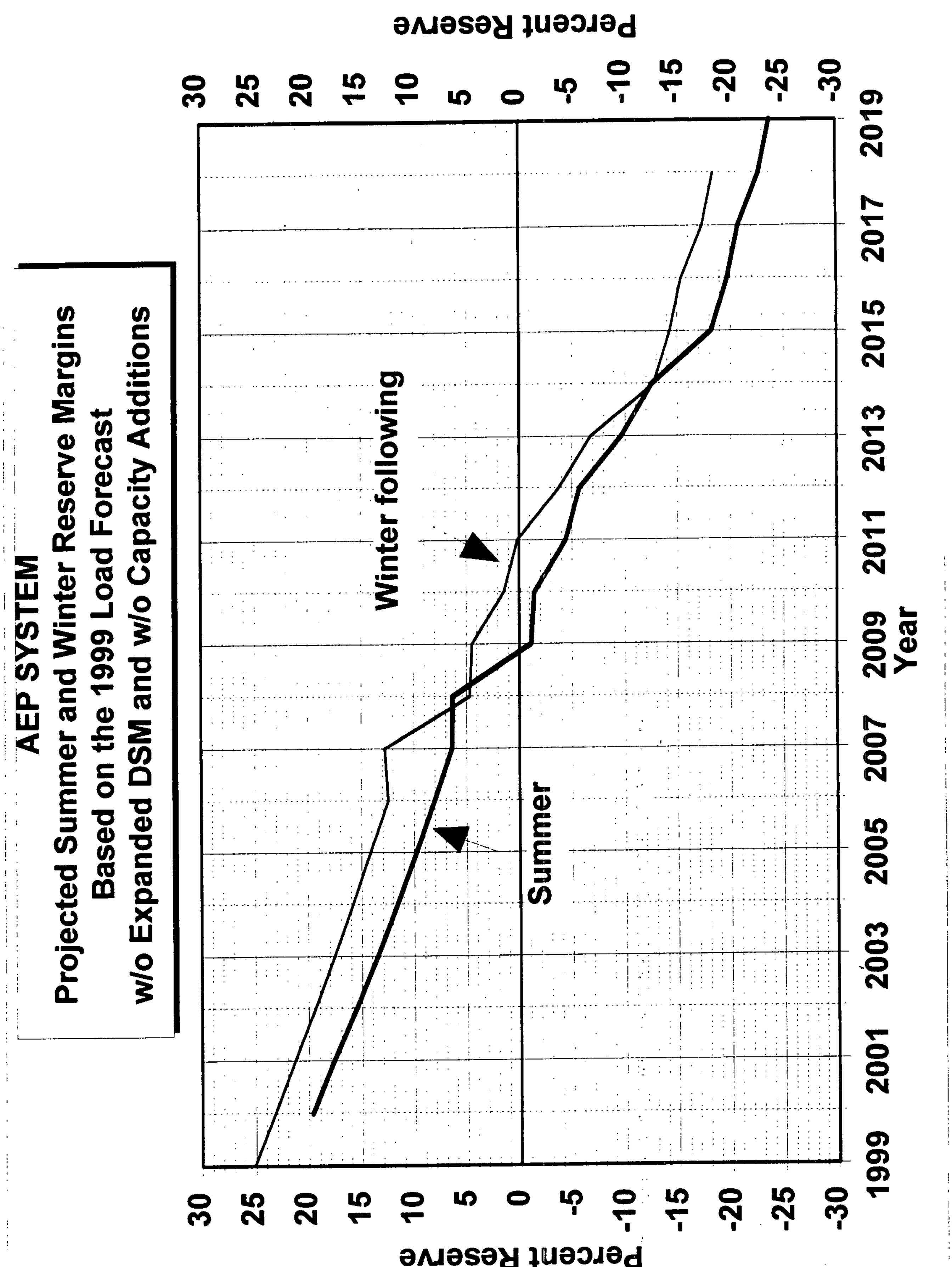
Note: (A) Excluding Unit Power Sales.

AMERICAN ELECTRIC POWER SYSTEM
(Including Buckeye Power)

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
1999/00 - 2018/19
Without Expanded DSM and New Resource Additions

		09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19
DEMAND											
1. Base Peak Internal Demand		21,976	22,265	22,553	22,842	23,131	23,419	23,708	23,997	24,285	24,574
2. Expanded DSM Programs		-	-	-	-	-	-	-	-	-	-
3. Adjusted Peak Internal Demand		21,976	22,265	22,553	22,842	23,131	23,419	23,708	23,997	24,285	24,574
4 Committed Capacity Sales (A)											
Richmond Power & Light (Firm)		-	-	-	-	-	-	-	-	-	-
NCEMC (Base-load Power)		205	-	-	-	-	-	-	-	-	-
Total		205	-	-	-	-	-	-	-	-	-
5 Total AEP Peak Demand		22,181	22,265	22,553	22,842	23,131	23,419	23,708	23,997	24,285	24,574
6 Buckeye Power Peak Demand		1,067	1,067	1,067	-	-	-	-	-	-	-
7 AEP + Buckeye Peak Demand		23,248	23,332	23,620	22,842	23,131	23,419	23,708	23,997	24,285	24,574
8 Interruptible Load		(681)	(681)	(681)	(681)	(681)	(681)	(681)	(681)	(681)	(681)
9. AEP + Buckeye Peak Demand Excluding Interruptible Load		22,567	22,651	22,939	22,161	22,450	22,738	23,027	23,316	23,604	23,893
GENERATING CAPABILITY (Seasonal)											
10. Capacity Before Changes											
AEP		22,325	22,325	21,725	21,725	21,310	20,910	19,820	19,720	19,720	19,480
Buckeye		1,230	1,230	1,230	-	-	-	-	-	-	-
Total		23,555	23,555	22,955	21,725	21,310	20,910	19,820	19,720	19,720	19,480
11. Capacity Changes											
Additions		-	-	-	-	-	-	-	-	-	-
Retirements		-	(600)	-	(415)	(400)	(1,090)	(100)	-	(240)	-
Rerates		-	-	-	-	-	-	-	-	-	-
Total		-	(600)	-	(415)	(400)	(1,090)	(100)	-	(240)	-
12 Capacity After Changes		23,555	22,955	22,955	21,310	20,910	19,820	19,720	19,720	19,480	19,480
13 Unit Power Sale - CP&L		-	-	-	-	-	-	-	-	-	-
14 Net Capacity		23,555	22,955	22,955	21,310	20,910	19,820	19,720	19,720	19,480	19,480
15 Firm Purchases - Non-Utility Generators		25	25	25	25	25	25	25	25	25	25
16 Total Capability		23,580	22,980	22,980	21,335	20,935	19,845	19,745	19,745	19,505	19,505
RESERVE MARGIN											
Based on Including Interruptible Load											
17 MW	(16)-(7)	332	(352)	(640)	(1,507)	(2,196)	(3,574)	(3,963)	(4,252)	(4,780)	(5,069)
18 Percent of Demand	[(17)/(7)]x100	1.4	(1.5)	(2.7)	(6.6)	(9.5)	(15.3)	(16.7)	(17.7)	(19.7)	(20.6)
Based on Excluding Interruptible Load											
19 MW	(16)-(9)	1,013	329	41	(826)	(1,515)	(2,893)	(3,282)	(3,571)	(4,099)	(4,388)
20 Percent of Demand	[(19)/(9)]x100	4.5	1.5	0.2	(3.7)	(6.7)	(12.7)	(14.3)	(15.3)	(17.4)	(18.4)

Note: (A) Excluding Unit Power Sales.


AEP SYSTEM
Projected Summer and Winter Reserve Margins
Based on the 1999 Load Forecast
w/o Expanded DSM and w/o Capacity Additions
Percent Reserve
30
25
20
15
10
5
0
-5
-10
-15
-20
-25
-30
Winter following
Summer
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
Year

KENTUCKY POWER COMPANY

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2000 - 2019
Without Expanded DSM and New Resource Additions

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DEMAND										
1. Base Peak Internal Demand	1,250	1,270	1,291	1,312	1,336	1,361	1,385	1,410	1,434	1,459
2. Expanded DSM Programs	-	-	-	-	-	-	-	-	-	-
3. Adjusted Peak Internal Demand	1,250	1,270	1,291	1,312	1,336	1,361	1,385	1,410	1,434	1,459
4 Committed Capacity Sales (A)(B)										
NCEMC (Base-load Power)	14	14	14	14	14	14	14	15	15	15
5 Total Peak Demand	1,264	1,284	1,305	1,326	1,350	1,375	1,399	1,425	1,449	1,474
GENERATING CAPABILITY (Seasonal)										
6 Capacity Before Changes	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
7 Capacity Changes										
Additions	-	-	-	-	-	-	-	-	-	-
Retirements	-	-	-	-	-	-	-	-	-	-
Rerates	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-
8 Capacity After Changes	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
9 Unit Power Purchase										
I&M/AEG (Affiliated)	390	390	390	390	390	-	-	-	-	-
10 Net Capacity	1,450	1,450	1,450	1,450	1,450	1,060	1,060	1,060	1,060	1,060
11 Firm Purchases - Non-Utility Generators	-	-	-	-	-	-	-	-	-	-
12 Total Capability	1,450	1,450	1,450	1,450	1,450	1,060	1,060	1,060	1,060	1,060
RESERVE MARGIN										
13 MW (12)-(5)	186	166	145	124	100	(315)	(339)	(365)	(389)	(414)
14 Percent of Demand [(13)/(5)]x100	14.7	12.9	11.1	9.4	7.4	(22.9)	(24.2)	(25.6)	(26.8)	(28.1)

Note: (A) Excluding Unit Power Sales.
(B) KPCo's member-load-ratio share.

Exhibit 4-16
(Page 2 of 2)

KENTUCKY POWER COMPANY

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2000 - 2019
Without Expanded DSM and New Resource Additions

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
DEMAND											
1. Base Peak Internal Demand		1,484	1,508	1,533	1,557	1,582	1,607	1,631	1,656	1,680	1,705
2. Expanded DSM Programs		-	-	-	-	-	-	-	-	-	-
3. Adjusted Peak Internal Demand		1,484	1,508	1,533	1,557	1,582	1,607	1,631	1,656	1,680	1,705
4 Committed Capacity Sales (A)(B)											
NCEMC (Base-load Power)		15	-	-	-	-	-	-	-	-	-
5 Total Peak Demand		1,499	1,508	1,533	1,557	1,582	1,607	1,631	1,656	1,680	1,705
GENERATING CAPABILITY (Seasonal)											
6 Capacity Before Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
7 Capacity Changes											
Additions		-	-	-	-	-	-	-	-	-	-
Retirements		-	-	-	-	-	-	-	-	-	-
Rerates		-	-	-	-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-	-	-	-
8 Capacity After Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
9 Unit Power Purchase		-	-	-	-	-	-	-	-	-	-
10 Net Capacity		1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
11 Firm Purchases - Non-Utility Generators		-	-	-	-	-	-	-	-	-	-
12 Total Capability		1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
RESERVE MARGIN											
13 MW	(12)-(5)	(439)	(448)	(473)	(497)	(522)	(547)	(571)	(596)	(620)	(645)
14 Percent of Demand	[(13)/(5)]x100	(29.3)	(29.7)	(30.9)	(31.9)	(33.0)	(34.0)	(35.0)	(36.0)	(36.9)	(37.8)

Note: (A) Excluding Unit Power Sales.
(B) KPCo's member-load-ratio share.

Exhibit 4-17
(Page 1 of 2)

KENTUCKY POWER COMPANY

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
1999/00 - 2018/19
Without Expanded DSM and New Resource Additions

	1999/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09
DEMAND										
1. Base Peak Internal Demand	1,462	1,488	1,512	1,537	1,570	1,602	1,635	1,667	1,699	1,732
2. Expanded DSM Programs	-	-	-	-	-	-	-	-	-	-
3. Adjusted Peak Internal Demand	1,462	1,488	1,512	1,537	1,570	1,602	1,635	1,667	1,699	1,732
4 Committed Capacity Sales (A)(B)										
NCEMC (Base-load Power)	14	14	14	14	14	14	14	14	14	14
5 Total Peak Demand	1,476	1,502	1,526	1,551	1,584	1,616	1,649	1,681	1,713	1,746
GENERATING CAPABILITY (Seasonal)										
6 Capacity Before Changes	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
7 Capacity Changes										
Additions	-	-	-	-	-	-	-	-	-	-
Retirements	-	-	-	-	-	-	-	-	-	-
Rerates	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-
8 Capacity After Changes	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
9 Unit Power Purchase										
I&M/AEG (Affiliated)	390	390	390	390	390	-	-	-	-	-
10 Net Capacity	1,450	1,450	1,450	1,450	1,450	1,060	1,060	1,060	1,060	1,060
11 Firm Purchases - Non-Utility Generators	-	-	-	-	-	-	-	-	-	-
12 Total Capability	1,450	1,450	1,450	1,450	1,450	1,060	1,060	1,060	1,060	1,060
RESERVE MARGIN										
13 MW (12)-(5)	(26)	(52)	(76)	(101)	(134)	(556)	(589)	(621)	(653)	(686)
14 Percent of Demand [(13)/(5)]x100	(1.8)	(3.5)	(5.0)	(6.5)	(8.5)	(34.4)	(35.7)	(36.9)	(38.1)	(39.3)

Note: (A) Excluding Unit Power Sales.
(B) KPCo's member-load-ratio share.

Exhibit 4-17
(Page 2 of 2)

KENTUCKY POWER COMPANY

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
1999/00 - 2018/19

Without Expanded DSM and New Resource Additions

	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19
DEMAND										
1. Base Peak Internal Demand	1,764	1,796	1,829	1,861	1,894	1,926	1,958	1,991	2,023	2,056
2. Expanded DSM Programs	-	-	-	-	-	-	-	-	-	-
3. Adjusted Peak Internal Demand	1,764	1,796	1,829	1,861	1,894	1,926	1,958	1,991	2,023	2,056
4 Committed Capacity Sales (A)(B)										
NCEMC (Base-load Power)	14	-	-	-	-	-	-	-	-	-
5 Total Peak Demand	1,778	1,796	1,829	1,861	1,894	1,926	1,958	1,991	2,023	2,056
GENERATING CAPABILITY (Seasonal)										
6 Capacity Before Changes	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
7 Capacity Changes										
Additions	-	-	-	-	-	-	-	-	-	-
Retirements	-	-	-	-	-	-	-	-	-	-
Rerates	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-
8 Capacity After Changes	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
9 Unit Power Purchase	-	-	-	-	-	-	-	-	-	-
10 Net Capacity	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
11 Firm Purchases - Non-Utility Generators	-	-	-	-	-	-	-	-	-	-
12 Total Capability	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
RESERVE MARGIN										
13 MW (12)-(5)	(718)	(736)	(769)	(801)	(834)	(866)	(898)	(931)	(963)	(996)
14 Percent of Demand [(13)/(5)]x100	(40.4)	(41.0)	(42.0)	(43.0)	(44.0)	(45.0)	(45.9)	(46.8)	(47.6)	(48.4)

Note: (A) Excluding Unit Power Sales.
(B) KPCo's member-load-ratio share.

Exhibit 4-18

AMERICAN ELECTRIC POWER SYSTEM
(Including Buckeye Power)

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2000 - 2019
With Expanded DSM and New Resource Additions

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DEMAND										
1. Base Peak Internal Demand	19,727	20,060	20,407	20,757	21,088	21,419	21,750	22,080	22,411	22,742
2. Expanded DSM Programs	(5)	(8)	(11)	(14)	(17)	(18)	(18)	(18)	(18)	(18)
3. Adjusted Peak Internal Demand	19,722	20,052	20,396	20,743	21,071	21,401	21,732	22,062	22,393	22,724
4 Committed Capacity Sales (A)										
Richmond Power & Light (Firm)	13	-	-	-	-	-	-	-	-	-
NCEMC (Base-load Power)	205	205	205	205	205	205	205	205	205	205
Total	218	205	205	205	205	205	205	205	205	205
5 Total AEP Peak Demand	19,940	20,257	20,601	20,948	21,276	21,606	21,937	22,267	22,598	22,929
6 Buckeye Power Peak Demand	1,160	1,208	1,238	1,269	1,298	1,331	1,360	1,392	1,067	1,067
7 AEP + Buckeye Peak Demand	21,100	21,465	21,839	22,217	22,574	22,937	23,297	23,659	23,665	23,996
8 Interruptible Load	(674)	(674)	(674)	(674)	(674)	(674)	(674)	(674)	(674)	(674)
9. AEP + Buckeye Peak Demand Excluding Interruptible Load	20,426	20,791	21,165	21,543	21,900	22,263	22,623	22,985	22,991	23,322
GENERATING CAPABILITY (Seasonal)										
10. Capacity Before Changes										
AEP	23,453	23,489	23,489	23,489	23,489	23,489	23,989	24,389	24,789	24,789
Buckeye	1,215	1,215	1,215	1,215	1,215	1,215	1,215	1,215	1,215	1,215
Total	24,668	24,704	24,704	24,704	24,704	24,704	25,204	25,604	26,004	26,004
11. Capacity Changes										
Additions (B)	-	-	-	-	-	500	400	400	-	1,800
Retirements	-	-	-	-	-	-	-	-	-	(1,390)
Rerates	36	-	-	-	-	-	-	-	-	-
Total	36	-	-	-	-	500	400	400	-	410
12 Capacity After Changes	24,704	24,704	24,704	24,704	24,704	25,204	25,604	26,004	26,004	26,414
13 Unit Power Sale - CP&L	(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)
14 Net Capacity	24,454	24,454	24,454	24,454	24,454	24,954	25,354	25,754	25,754	26,164
15 Firm Purchases - Non-Utility Generators	-	17	17	17	17	17	17	17	17	17
16 Total Capability	24,454	24,471	24,471	24,471	24,471	24,971	25,371	25,771	25,771	26,181
RESERVE MARGIN										
Based on Including Interruptible Load										
17 MW (16)-(7)	3,354	3,006	2,632	2,254	1,897	2,034	2,074	2,112	2,106	2,185
18 Percent of Demand [(17)/(7)]x100	15.9	14.0	12.1	10.1	8.4	8.9	8.9	8.9	8.9	9.1
Based on Excluding Interruptible Load										
19 MW (16)-(9)	4,028	3,680	3,306	2,928	2,571	2,708	2,748	2,786	2,780	2,859
20 Percent of Demand [(19)/(9)]x100	19.7	17.7	15.6	13.6	11.7	12.2	12.1	12.1	12.1	12.3

Note: (A) Excluding Unit Power Sales.
(B) Undesignated.

AMERICAN ELECTRIC POWER SYSTEM
(Including Buckeye Power)

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2000 - 2019
With Expanded DSM and New Resource Additions

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
DEMAND											
1. Base Peak Internal Demand		23,073	23,403	23,734	24,065	24,395	24,726	25,057	25,388	25,718	26,049
2. Expanded DSM Programs		(18)	(18)	(18)	(18)	(16)	(13)	(10)	(8)	(8)	(8)
3. Adjusted Peak Internal Demand		23,055	23,385	23,716	24,047	24,379	24,713	25,047	25,380	25,710	26,041
4 Committed Capacity Sales (A)											
Richmond Power & Light (Firm)		-	-	-	-	-	-	-	-	-	-
NCEMC (Base-load Power)		205	-	-	-	-	-	-	-	-	-
Total		205	-	-	-	-	-	-	-	-	-
5 Total AEP Peak Demand		23,260	23,385	23,716	24,047	24,379	24,713	25,047	25,380	25,710	26,041
6 Buckeye Power Peak Demand		1,067	1,067	1,067	-	-	-	-	-	-	-
7 AEP + Buckeye Peak Demand		24,327	24,452	24,783	24,047	24,379	24,713	25,047	25,380	25,710	26,041
8 Interruptible Load		(674)	(674)	(674)	(674)	(674)	(674)	(674)	(674)	(674)	(674)
9. AEP + Buckeye Peak Demand Excluding Interruptible Load		23,653	23,778	24,109	23,373	23,705	24,039	24,373	24,706	25,036	25,367
GENERATING CAPABILITY (Seasonal)											
10. Capacity Before Changes											
AEP		25,199	25,299	25,419	25,819	26,224	26,534	26,964	27,274	27,674	28,039
Buckeye		1,215	1,215	1,215	-	-	-	-	-	-	-
Total		26,414	26,514	26,634	25,819	26,224	26,534	26,964	27,274	27,674	28,039
11. Capacity Changes											
Additions (B)		100	700	400	800	700	1,500	400	400	600	400
Retirements		-	(580)	-	(395)	(390)	(1,070)	(90)	-	(235)	-
Rerates		-	-	-	-	-	-	-	-	-	-
Total		100	120	400	405	310	430	310	400	365	400
12 Capacity After Changes		26,514	26,634	27,034	26,224	26,534	26,964	27,274	27,674	28,039	28,439
13 Unit Power Sale - CP&L		-	-	-	-	-	-	-	-	-	-
14 Net Capacity		26,514	26,634	27,034	26,224	26,534	26,964	27,274	27,674	28,039	28,439
15 Firm Purchases - Non-Utility Generators		17	17	17	17	17	17	17	17	17	17
16 Total Capability		26,531	26,651	27,051	26,241	26,551	26,981	27,291	27,691	28,056	28,456
RESERVE MARGIN											
Based on Including Interruptible Load											
17 MW	(16)-(7)	2,204	2,199	2,268	2,194	2,172	2,268	2,244	2,311	2,346	2,415
18 Percent of Demand	[(17)/(7)]x100	9.1	9.0	9.2	9.1	8.9	9.2	9.0	9.1	9.1	9.3
Based on Excluding Interruptible Load											
19 MW	(16)-(9)	2,878	2,873	2,942	2,868	2,846	2,942	2,918	2,985	3,020	3,089
20 Percent of Demand	[(19)/(9)]x100	12.2	12.1	12.2	12.3	12.0	12.2	12.0	12.1	12.1	12.2

Note: (A) Excluding Unit Power Sales.
(B) Undesignated.

AMERICAN ELECTRIC POWER SYSTEM
(Including Buckeye Power)

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
1999/00 - 2018/19
With Expanded DSM and New Resource Additions

		1999/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09
DEMAND											
1. Base Peak Internal Demand		19,082	19,372	19,660	19,955	20,244	20,533	20,821	21,110	21,399	21,687
2. Expanded DSM Programs		(11)	(21)	(30)	(40)	(50)	(61)	(61)	(61)	(61)	(60)
3. Adjusted Peak Internal Demand		19,071	19,351	19,630	19,915	20,194	20,472	20,760	21,049	21,338	21,627
4 Committed Capacity Sales (A)											
Richmond Power & Light (Firm)		13	-	-	-	-	-	-	-	-	-
NCEMC (Base-load Power)		205	205	205	205	205	205	205	205	205	205
Total		218	205	205	205	205	205	205	205	205	205
5 Total AEP Peak Demand		19,289	19,556	19,835	20,120	20,399	20,677	20,965	21,254	21,543	21,832
6 Buckeye Power Peak Demand		1,177	1,228	1,258	1,289	1,319	1,351	1,380	1,412	1,067	1,067
7 AEP + Buckeye Peak Demand		20,466	20,784	21,093	21,409	21,718	22,028	22,345	22,666	22,610	22,899
8 Interruptible Load		(681)	(681)	(681)	(681)	(681)	(681)	(681)	(681)	(681)	(681)
9. AEP + Buckeye Peak Demand Excluding Interruptible Load		19,785	20,103	20,412	20,728	21,037	21,347	21,664	21,985	21,929	22,218
GENERATING CAPABILITY (Seasonal)											
10. Capacity Before Changes											
AEP		23,759	23,795	23,795	23,795	23,795	23,795	24,295	24,695	25,095	25,095
Buckeye		1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230
Total		24,989	25,025	25,025	25,025	25,025	25,025	25,525	25,925	26,325	26,325
11. Capacity Changes											
Additions (B)		-	-	-	-	-	500	400	400	-	1,800
Retirements		-	-	-	-	-	-	-	-	-	(1,470)
Rerates		36	-	-	-	-	-	-	-	-	-
Total		36	-	-	-	-	500	400	400	-	330
12 Capacity After Changes		25,025	25,025	25,025	25,025	25,025	25,525	25,925	26,325	26,325	26,655
13 Unit Power Sale - CP&L		(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)
14 Net Capacity		24,775	24,775	24,775	24,775	24,775	25,275	25,675	26,075	26,075	26,405
15 Firm Purchases - Non-Utility Generators		-	25	25	25	25	25	25	25	25	25
16 Total Capability		24,775	24,800	24,800	24,800	24,800	25,300	25,700	26,100	26,100	26,430
RESERVE MARGIN											
Based on Including Interruptible Load											
17 MW	(16)-(7)	4,309	4,016	3,707	3,391	3,082	3,272	3,355	3,434	3,490	3,531
18 Percent of Demand	[(17)/(7)]x100	21.1	19.3	17.6	15.8	14.2	14.9	15.0	15.2	15.4	15.4
Based on Excluding Interruptible Load											
19 MW	(16)-(9)	4,990	4,697	4,388	4,072	3,763	3,953	4,036	4,115	4,171	4,212
20 Percent of Demand	[(19)/(9)]x100	25.2	23.4	21.5	19.6	17.9	18.5	18.6	18.7	19.0	19.0

Note: (A) Excluding Unit Power Sales.
(B) Undesignated.

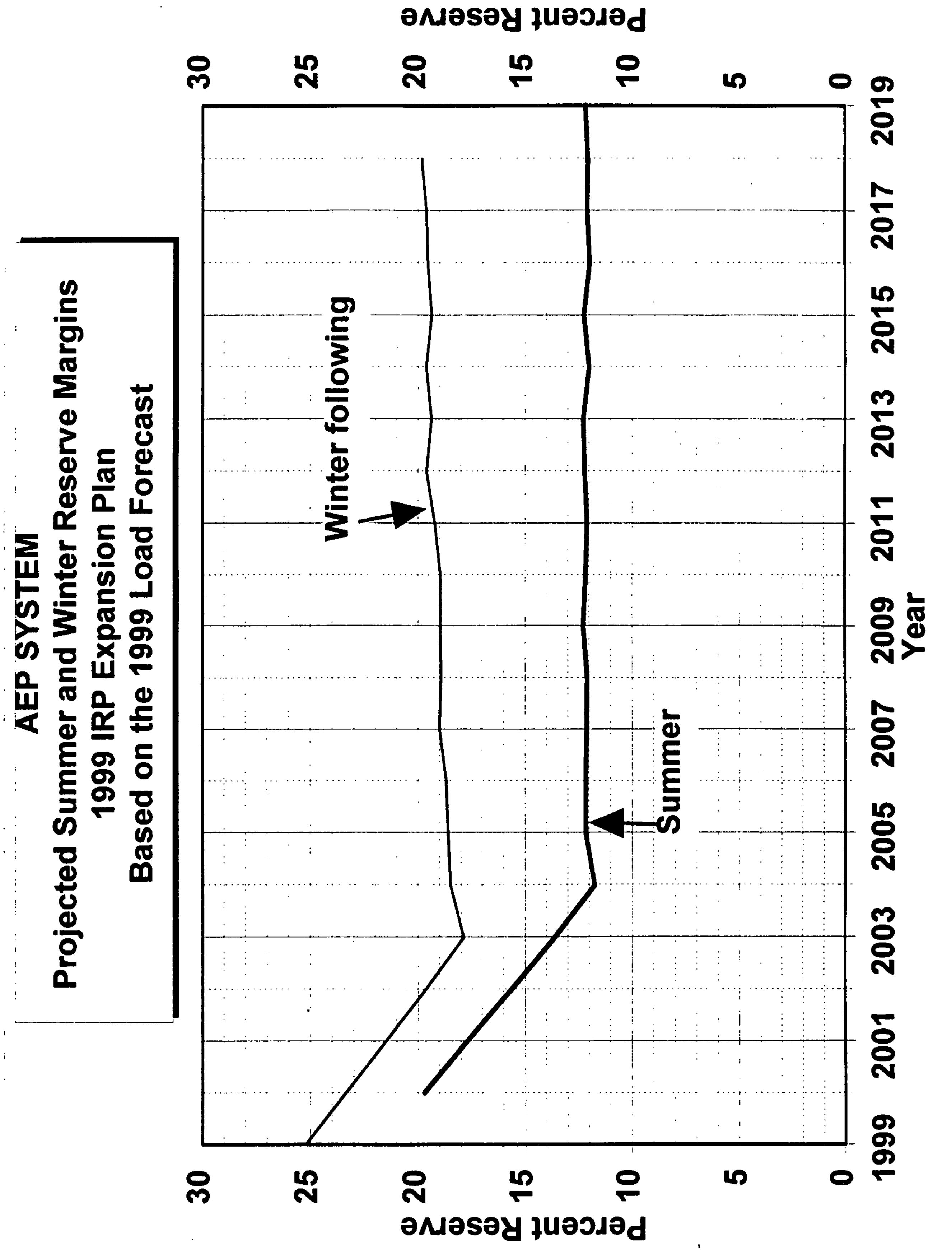
AMERICAN ELECTRIC POWER SYSTEM
(Including Buckeye Power)

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
1999/00 - 2018/19

With Expanded DSM and New Resource Additions

		09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19
DEMAND											
1. Base Peak Internal Demand		21,976	22,265	22,553	22,842	23,131	23,419	23,708	23,997	24,285	24,574
2. Expanded DSM Programs		(60)	(60)	(60)	(60)	(60)	(49)	(40)	(30)	(30)	(30)
3. Adjusted Peak Internal Demand		21,916	22,205	22,493	22,782	23,071	23,370	23,668	23,967	24,255	24,544
4 Committed Capacity Sales (A)											
Richmond Power & Light (Firm)		-	-	-	-	-	-	-	-	-	-
NCEMC (Base-load Power)		205	-	-	-	-	-	-	-	-	-
Total		205	-	-	-	-	-	-	-	-	-
5 Total AEP Peak Demand		22,121	22,205	22,493	22,782	23,071	23,370	23,668	23,967	24,255	24,544
6 Buckeye Power Peak Demand		1,067	1,067	1,067	-	-	-	-	-	-	-
7 AEP + Buckeye Peak Demand		23,188	23,272	23,560	22,782	23,071	23,370	23,668	23,967	24,255	24,544
8 Interruptible Load		(681)	(681)	(681)	(681)	(681)	(681)	(681)	(681)	(681)	(681)
9. AEP + Buckeye Peak Demand Excluding Interruptible Load		22,507	22,591	22,879	22,101	22,390	22,689	22,987	23,286	23,574	23,863
GENERATING CAPABILITY (Seasonal)											
10. Capacity Before Changes											
AEP		25,425	25,525	25,625	26,025	26,410	26,710	27,120	27,420	27,820	28,180
Buckeye		1,230	1,230	1,230	-	-	-	-	-	-	-
Total		26,655	26,755	26,855	26,025	26,410	26,710	27,120	27,420	27,820	28,180
11. Capacity Changes											
Additions (B)		100	700	400	800	700	1,500	400	400	600	400
Retirements		-	(600)	-	(415)	(400)	(1,090)	(100)	-	(240)	-
Rerates		-	-	-	-	-	-	-	-	-	-
Total		100	100	400	385	300	410	300	400	360	400
12 Capacity After Changes		26,755	26,855	27,255	26,410	26,710	27,120	27,420	27,820	28,180	28,580
13 Unit Power Sale - CP&L		-	-	-	-	-	-	-	-	-	-
14 Net Capacity		26,755	26,855	27,255	26,410	26,710	27,120	27,420	27,820	28,180	28,580
15 Firm Purchases - Non-Utility Generators		25	25	25	25	25	25	25	25	25	25
16 Total Capability		26,780	26,880	27,280	26,435	26,735	27,145	27,445	27,845	28,205	28,605
RESERVE MARGIN											
Based on Including Interruptible Load											
17 MW	(16)-(7)	3,592	3,608	3,720	3,653	3,664	3,775	3,777	3,878	3,950	4,061
18 Percent of Demand	[(17)/(7)]x100	15.5	15.5	15.8	16.0	15.9	16.2	16.0	16.2	16.3	16.5
Based on Excluding Interruptible Load											
19 MW	(16)-(9)	4,273	4,289	4,401	4,334	4,345	4,456	4,458	4,559	4,631	4,742
20 Percent of Demand	[(19)/(9)]x100	19.0	19.0	19.2	19.6	19.4	19.6	19.4	19.6	19.6	19.9

Note: (A) Excluding Unit Power Sales.
(B) Undesignated.


AEP SYSTEM
Projected Summer and Winter Reserve Margins
1999 IRP Expansion Plan
Based on the 1999 Load Forecast
Winter following
Summer
Percent Reserve
Year
1999 2001 2003 2005 2007 2009 2011 2013 2015 2017 2019
0 5 10 15 20 25 30

KENTUCKY POWER COMPANY

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2000 - 2019
With Expanded DSM and New Resource Additions

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DEMAND										
1. Base Peak Internal Demand	1,250	1,270	1,291	1,312	1,336	1,361	1,385	1,410	1,434	1,459
2. Expanded DSM Programs	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(2)
3. Adjusted Peak Internal Demand	1,249	1,269	1,290	1,311	1,335	1,359	1,383	1,408	1,432	1,457
4 Committed Capacity Sales (A)(B)										
NCEMC (Base-load Power)	14	14	14	14	14	14	14	15	15	15
5 Total Peak Demand	1,263	1,283	1,304	1,325	1,349	1,373	1,397	1,423	1,447	1,472
GENERATING CAPABILITY (Seasonal)										
6 Capacity Before Changes	1,060	1,060	1,060	1,060	1,060	1,060	1,360	1,460	1,560	1,560
7 Capacity Changes										
Additions (C)	-	-	-	-	-	300	100	100	-	200
Retirements	-	-	-	-	-	-	-	-	-	-
Rerates	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	300	100	100	-	200
8 Capacity After Changes	1,060	1,060	1,060	1,060	1,060	1,360	1,460	1,560	1,560	1,760
9 Unit Power Purchase										
I&M/AEG (Affiliated)	390	390	390	390	390	-	-	-	-	-
10 Net Capacity	1,450	1,450	1,450	1,450	1,450	1,360	1,460	1,560	1,560	1,760
11 Firm Purchases - Non-Utility Generators	-	-	-	-	-	-	-	-	-	-
12 Total Capability	1,450	1,450	1,450	1,450	1,450	1,360	1,460	1,560	1,560	1,760
RESERVE MARGIN										
13 MW (12)-(5)	187	167	146	125	101	(13)	63	137	113	288
14 Percent of Demand [(13)/(5)]x100	14.8	13.0	11.2	9.4	7.5	(0.9)	4.5	9.6	7.8	19.6

Note: (A) Excluding Unit Power Sales.
(B) KPCo's member-load-ratio share.
(C) Undesignated.

Exhibit 4-21
(Page 2 of 2)

KENTUCKY POWER COMPANY

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2000 - 2019
With Expanded DSM and New Resource Additions

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
DEMAND										
1. Base Peak Internal Demand	1,484	1,508	1,533	1,557	1,582	1,607	1,631	1,656	1,680	1,705
2. Expanded DSM Programs	(2)	(2)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	(1)
3. Adjusted Peak Internal Demand	1,482	1,506	1,531	1,555	1,581	1,606	1,630	1,655	1,679	1,704
4 Committed Capacity Sales (A)(B)										
NCEMC (Base-load Power)	15	-	-	-	-	-	-	-	-	-
5 Total Peak Demand	1,497	1,506	1,531	1,555	1,581	1,606	1,630	1,655	1,679	1,704
GENERATING CAPABILITY (Seasonal)										
6 Capacity Before Changes	1,760	1,760	1,860	1,860	1,860	1,960	2,060	2,060	2,060	2,160
7 Capacity Changes										
Additions (C)	-	100	-	-	100	100	-	-	100	-
Retirements	-	-	-	-	-	-	-	-	-	-
Rerates	-	-	-	-	-	-	-	-	-	-
Total	-	100	-	-	100	100	-	-	100	-
8 Capacity After Changes	1,760	1,860	1,860	1,860	1,960	2,060	2,060	2,060	2,160	2,160
9 Unit Power Purchase	-	-	-	-	-	-	-	-	-	-
10 Net Capacity	1,760	1,860	1,860	1,860	1,960	2,060	2,060	2,060	2,160	2,160
11 Firm Purchases - Non-Utility Generators	-	-	-	-	-	-	-	-	-	-
12 Total Capability	1,760	1,860	1,860	1,860	1,960	2,060	2,060	2,060	2,160	2,160
RESERVE MARGIN										
13 MW (12)-(5)	263	354	329	305	379	454	430	405	481	456
14 Percent of Demand [(13)/(5)]x100	17.6	23.5	21.5	19.6	24.0	28.3	26.4	24.5	28.6	26.8

Note: (A) Excluding Unit Power Sales.
(B) KPCo's member-load-ratio share.
(C) Undesignated.

Exhibit 4-22
(Page 1 of 2)

KENTUCKY POWER COMPANY

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
1999/00 - 2018/19
With Expanded DSM and New Resource Additions

	1999/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09
DEMAND										
1. Base Peak Internal Demand	1,462	1,488	1,512	1,537	1,570	1,602	1,635	1,667	1,699	1,732
2. Expanded DSM Programs	(2)	(2)	(3)	(4)	(4)	(5)	(5)	(5)	(5)	(5)
3. Adjusted Peak Internal Demand	1,460	1,486	1,509	1,533	1,566	1,597	1,630	1,662	1,694	1,727
4 Committed Capacity Sales (A)(B)										
NCEMC (Base-load Power)	14	14	14	14	14	14	14	14	14	14
5 Total Peak Demand	1,474	1,500	1,523	1,547	1,580	1,611	1,644	1,676	1,708	1,741
GENERATING CAPABILITY (Seasonal)										
6 Capacity Before Changes	1,060	1,060	1,060	1,060	1,060	1,060	1,360	1,460	1,560	1,560
7 Capacity Changes										
Additions (C)	-	-	-	-	-	300	100	100	-	200
Retirements	-	-	-	-	-	-	-	-	-	-
Rerates	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	300	100	100	-	200
8 Capacity After Changes	1,060	1,060	1,060	1,060	1,060	1,360	1,460	1,560	1,560	1,760
9 Unit Power Purchase	390	390	390	390	390	-	-	-	-	-
10 Net Capacity	1,450	1,450	1,450	1,450	1,450	1,360	1,460	1,560	1,560	1,760
11 Firm Purchases - Non-Utility Generators	-	-	-	-	-	-	-	-	-	-
12 Total Capability	1,450	1,450	1,450	1,450	1,450	1,360	1,460	1,560	1,560	1,760
RESERVE MARGIN										
13 MW (12)-(5)	(24)	(50)	(73)	(97)	(130)	(251)	(184)	(116)	(148)	19
14 Percent of Demand [(13)/(5)]x100	(1.6)	(3.3)	(4.8)	(6.3)	(8.2)	(15.6)	(11.2)	(6.9)	(8.7)	1.1

Note: (A) Excluding Unit Power Sales.
(B) KPCo's member-load-ratio share.
(C) Undesignated.

KENTUCKY POWER COMPANY

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
1999/00 - 2018/19
With Expanded DSM and New Resource Additions

	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19
DEMAND										
1. Base Peak Internal Demand	1,764	1,796	1,829	1,861	1,894	1,926	1,958	1,991	2,023	2,056
2. Expanded DSM Programs	(5)	(5)	(5)	(5)	(5)	(3)	(3)	(2)	(2)	(2)
3. Adjusted Peak Internal Demand	1,759	1,791	1,824	1,856	1,889	1,923	1,955	1,989	2,021	2,054
4 Committed Capacity Sales (A)(B)										
NCEMC (Base-load Power)	14	-	-	-	-	-	-	-	-	-
5 Total Peak Demand	1,773	1,791	1,824	1,856	1,889	1,923	1,955	1,989	2,021	2,054
GENERATING CAPABILITY (Seasonal)										
6 Capacity Before Changes	1,760	1,760	1,860	1,860	1,860	1,960	2,060	2,060	2,060	2,160
7 Capacity Changes										
Additions (C)	-	100	-	-	100	100	0	0	100	0
Retirements	-	-	-	-	-	-	-	-	-	-
Rerates	-	-	-	-	-	-	-	-	-	-
Total	-	100	-	-	100	100	0	0	100	0
8 Capacity After Changes	1,760	1,860	1,860	1,860	1,960	2,060	2,060	2,060	2,160	2,160
9 Unit Power Purchase	-	-	-	-	-	-	-	-	-	-
10 Net Capacity	1,760	1,860	1,860	1,860	1,960	2,060	2,060	2,060	2,160	2,160
11 Firm Purchases - Non-Utility Generators	-	-	-	-	-	-	-	-	-	-
12 Total Capability	1,760	1,860	1,860	1,860	1,960	2,060	2,060	2,060	2,160	2,160
RESERVE MARGIN										
13 MW (12)-(5)	(13)	69	36	4	71	137	105	71	139	106
14 Percent of Demand [(13)/(5)]x100	(0.7)	3.9	2.0	0.2	3.8	7.1	5.4	3.6	6.9	5.2

Note: (A) Excluding Unit Power Sales.
(B) KPCo's member-load-ratio share.
(C) Undesignated.

KENTUCKY POWER COMPANY
Annual Internal Energy Requirements, Energy Resources and Energy Inputs
2000 - 2013
(GWh)

	Energy Requirements			Energy Resources								Energy Inputs (By Primary Fuel Type)			
				Generation(By Primary Fuel Type)					Firm Purchases			Coal-fired Generation		Gas-fired Generation	
Year	Base Forecast Internal Energy Requirements	Conservation Load Management	Adjusted Energy	Coal	Oil	Gas (A)	Hydro	Total	Other Utilities(B)	NUG	Total(C)	Tons (000)	MBtu (000)	MCF (000)	MBtu (000)
2000	7,406	(4)	7,402	7,713	--	--	--	7,713	2,804	--	10,517	2,924	71,083	--	--
2001	7,524	(4)	7,520	7,946	--	--	--	7,946	2,787	--	10,733	3,026	73,189	--	--
2002	7,632	(5)	7,627	8,514	--	--	--	8,514	2,861	--	11,375	3,242	78,485	--	--
2003	7,746	(6)	7,740	7,409	--	--	--	7,409	2,751	--	10,160	2,822	68,310	--	--
2004	7,895	(7)	7,888	8,551	--	--	--	8,551	2,783	--	11,334	3,251	78,809	--	--
2005	8,045	(7)	8,038	8,073	--	634	--	8,707	--	--	8,707	3,070	74,371	6,689	6,856
2006	8,194	(7)	8,187	8,579	--	941	--	9,520	--	--	9,520	3,261	79,032	9,922	10,170
2007	8,343	(7)	8,336	7,637	--	1,150	--	8,787	--	--	8,787	2,909	70,371	12,128	12,431
2008	8,493	(7)	8,486	8,575	--	1,113	--	9,688	--	--	9,688	3,260	79,018	11,740	12,034
2009	8,642	(7)	8,635	8,158	--	2,491	--	10,649	--	--	10,649	3,132	75,169	26,275	26,932
2010	8,792	(7)	8,785	8,166	--	2,451	--	10,617	--	--	10,617	3,135	75,241	25,848	26,494
2011	8,941	(7)	8,934	8,141	--	2,742	--	10,883	--	--	10,883	3,126	75,028	28,916	29,639
2012	9,090	(7)	9,083	8,182	--	2,729	--	10,911	--	--	10,911	3,141	75,392	28,780	29,500
2013	9,240	(7)	9,233	8,176	--	3,203	--	11,379	--	--	11,379	3,139	75,327	33,782	34,627

Notes: (A) Assumes that new generation resources, although currently undesignated, are all additions of gas-fired combustion turbine units.

(B) Rockport Unit Power purchase from AEG (an affiliated company) through 2004.

(C) The difference between Energy Requirements and Energy Resources represents net energy received from or delivered to the AEP Pool.

Exhibit 4-24

AEP SYSTEM
INITIAL YEAR OF
NEW GENERATION RESOURCE ADDITIONS

LOAD FORECAST	WITHOUT DSM	WITH DSM
LOW 1.0%	2007	2007
BASE 1.4%	2005	2005
HIGH 1.8%	2003	2003

AEP SYSTEM
Comparison of 1996 and 1999 Capacity Expansion Plans

	1996 Plan (1993-2014)			1999 Plan (1999-2019)		
		MW			MW	
Year	Unit Additions	AEP	KPCo Portion	100-MW Block Additions (Undesignated)	AEP	KPCo Portion
2001	-	-		-	-	
2002	5 170-MW CT	850		-	-	
2003	3 170-MW CT	510	170	-	-	
2004	4 170-MW CT	680		-	-	
2005	3 170-MW CT	510	340	5	500	300
2006	4 170-MW CT	680		4	400	100
2007	-	-		4	400	100
2008	1 170-MW CT	170		-	-	
2009	6 170-MW CT					
	2 405-MW CC	1,830		18	1,800	200
2010	-	-		1	100	
2011	2 170-MW CT					
	1 405-MW CC	745	405	7	700	100
2012	1 170-MW CT	170		4	400	
2013	2 405-MW CC	810		8	800	
2014	2 170-MW CT					
	1 405-MW CC	745		7	700	100
2015	1 405-MW CC					
	1 910-MW Coal	1,315		15	1,500	100
2016	2 170-MW CT	340		4	400	
2017				4	400	
2018				6	600	100
2019				4	400	
Through 2016	33 170-MW CT	5,610	510			
	7 405-MW CC	2,835	405			
	1 910-MW Coal	910				
	Total	9,355	915	Total	7,700	1,000
Through 2019				Total	9,100	1,100

Kentucky Power Company

Model Equations

Results of Statistical Tests and Input Data Sets

Pertaining to the 1999 Load Forecast

KPCo 1999

Contents

Included herein are input data, model equations, and statistical results for the numerous forecasting models employed in developing the 1999 Load Forecast for Kentucky Power Company. Those forecasted concepts that are produced judgmentally, without the use of econometric models, are not shown. The pages included here are copied directly from computer output. In most cases, that output contains a data glossary, identifying the names of variables appearing in the models (or the variables are labelled in the equations). The one exception is the output for the short-term energy models, to which a data glossary has been added. The models are shown in the following order:

Kentucky Power Company

Short-Term Energy Models
Data Glossary

Endogenous Variables

ER_KPC	Residential Energy Sales
EC_KPC	Commercial Energy Sales
EIX_KPC	Manufacturing Energy Sales
EIM_KPC	Mine Power Energy Sales
EUL_KPC	Street & Highway Lighting Energy Sales
EOM_KPC	Energy Sales to Municipals
EL_KPC	Losses and Unaccounted-for Energy

Exogenous Variables

CDD_KPC	Cooling Degree-days KPC service area
CDD2_KPC	Cooling Degree-days KPC service area, squared
HDD_KPC	Heating Degree-days KPC service area
HDD2_KPC	Heating Degree-days KPC service area, squared
HDD3_KPC	Heating Degree-days KPC service area, cubed
FRB331	FRB Industrial Production Index - Primary Metals
D1	Binary: January
D2	Binary: February
D3	Binary: March
D4	Binary: April
D5	Binary: May
D6	Binary: June
D7	Binary: July
D8	Binary: August
D9	Binary: September
DA	Binary: October
DB	Binary: November
DM941ON	Binary: Month of January 1994 on
DM942ON	Binary: Month of February 1994 on
DM943ON	Binary: Month of March 1994 on
DM944ON	Binary: Month of April 1994 on
DM945ON	Binary: Month of May 1994 on
DM946ON	Binary: Month of June 1994 on
DM947ON	Binary: Month of July 1994 on

DM948ON	Binary: Month of August 1994 on
DM949ON	Binary: Month of September 1994 on
DM94AON	Binary: Month of October 1994 on
DM94BON	Binary: Month of November 1994 on
D894896	Binary: April 1989 through June 1989
D899ON	Binary: September 1989 on
D90A914	Binary: October 1990 through April 1991
D92292A	Binary: February 1992 through October 1992
D927947	Binary: July 1992 through July 1994
D941ON	Binary: January 1994 on
D94294C	Binary: February 1994 through December 1994
D95C	Binary: December 1995
D955ON	Binary: May 1995 on
D956ON	Binary: June 1996 on
D961	Binary: January 1996
D961967	Binary: January 1996 through July 1997
D962	Binary: February 1996
D963	Binary: March 1996
D967971	Binary: July 1996 through January 1997
D97B	Binary: November 1997
D971ON	Binary: January 1997 on
D977	Binary: July 1997
D97797A	Binary: July 1997 through October 1997
D978	Binary: August 1997
D981	Binary: January 1998
D983	Binary: March 1998
D983987	Binary: March 1998 through July 1998
D987	Binary: July 1998
T	Time Trend
T941ON	Time Trend - January 1994 on

SHORT TERM MODELS
BINARY VARIABLES

YEAR	MONTH	DA	DB	DM94AON	DM94BON	DM9410N
1988	1	0	0	0	0	0
1988	2	0	0	0	0	0
1988	3	0	0	0	0	0
1988	4	0	0	0	0	0
1988	5	0	0	0	0	0
1988	6	0	0	0	0	0
1988	7	0	0	0	0	0
1988	8	0	0	0	0	0
1988	9	0	0	0	0	0
1988	10	1	0	0	0	0
1988	11	0	1	0	0	0
1988	12	0	0	0	0	0
1989	1	0	0	0	0	0
1989	2	0	0	0	0	0
1989	3	0	0	0	0	0
1989	4	0	0	0	0	0
1989	5	0	0	0	0	0
1989	6	0	0	0	0	0
1989	7	0	0	0	0	0
1989	8	0	0	0	0	0
1989	9	0	0	0	0	0
1989	10	1	0	0	0	0
1989	11	0	1	0	0	0
1989	12	0	0	0	0	0
1990	1	0	0	0	0	0
1990	2	0	0	0	0	0
1990	3	0	0	0	0	0
1990	4	0	0	0	0	0
1990	5	0	0	0	0	0
1990	6	0	0	0	0	0
1990	7	0	0	0	0	0
1990	8	0	0	0	0	0
1990	9	0	0	0	0	0
1990	10	1	0	0	0	0
1990	11	0	1	0	0	0
1990	12	0	0	0	0	0
1991	1	0	0	0	0	0
1991	2	0	0	0	0	0
1991	3	0	0	0	0	0
1991	4	0	0	0	0	0
1991	5	0	0	0	0	0
1991	6	0	0	0	0	0
1991	7	0	0	0	0	0
1991	8	0	0	0	0	0
1991	9	0	0	0	0	0
1991	10	1	0	0	0	0
1991	11	0	1	0	0	0
1991	12	0	0	0	0	0
1992	1	0	0	0	0	0
1992	2	0	0	0	0	0
1992	3	0	0	0	0	0
1992	4	0	0	0	0	0
1992	5	0	0	0	0	0
1992	6	0	0	0	0	0
1992	7	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES

YEAR	MONTH	DA	DB	DM94AON	DM94BON	DM9410N
1992	8	0	0	0	0	0
1992	9	0	0	0	0	0
1992	10	1	0	0	0	0
1992	11	0	1	0	0	0
1992	12	0	0	0	0	0
1993	1	0	0	0	0	0
1993	2	0	0	0	0	0
1993	3	0	0	0	0	0
1993	4	0	0	0	0	0
1993	5	0	0	0	0	0
1993	6	0	0	0	0	0
1993	7	0	0	0	0	0
1993	8	0	0	0	0	0
1993	9	0	0	0	0	0
1993	10	1	0	0	0	0
1993	11	0	1	0	0	0
1993	12	0	0	0	0	0
1994	1	0	0	0	0	1
1994	2	0	0	0	0	0
1994	3	0	0	0	0	0
1994	4	0	0	0	0	0
1994	5	0	0	0	0	0
1994	6	0	0	0	0	0
1994	7	0	0	0	0	0
1994	8	0	0	0	0	0
1994	9	0	0	0	0	0
1994	10	1	0	1	0	0
1994	11	0	1	0	1	0
1994	12	0	0	0	0	0
1995	1	0	0	0	0	1
1995	2	0	0	0	0	0
1995	3	0	0	0	0	0
1995	4	0	0	0	0	0
1995	5	0	0	0	0	0
1995	6	0	0	0	0	0
1995	7	0	0	0	0	0
1995	8	0	0	0	0	0
1995	9	0	0	0	0	0
1995	10	1	0	1	0	0
1995	11	0	1	0	1	0
1995	12	0	0	0	0	0
1996	1	0	0	0	0	1
1996	2	0	0	0	0	0
1996	3	0	0	0	0	0
1996	4	0	0	0	0	0
1996	5	0	0	0	0	0
1996	6	0	0	0	0	0
1996	7	0	0	0	0	0
1996	8	0	0	0	0	0
1996	9	0	0	0	0	0
1996	10	1	0	1	0	0
1996	11	0	1	0	1	0
1996	12	0	0	0	0	0
1997	1	0	0	0	0	1
1997	2	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES

YEAR	MONTH	DA	DB	DM94AON	DM94BON	DM941ON
1997	3	0	0	0	0	0
1997	4	0	0	0	0	0
1997	5	0	0	0	0	0
1997	6	0	0	0	0	0
1997	7	0	0	0	0	0
1997	8	0	0	0	0	0
1997	9	0	0	0	0	0
1997	10	1	0	1	0	0
1997	11	0	1	0	1	0
1997	12	0	0	0	0	0
1998	1	0	0	0	0	1
1998	2	0	0	0	0	0
1998	3	0	0	0	0	0
1998	4	0	0	0	0	0
1998	5	0	0	0	0	0
1998	6	0	0	0	0	0
1998	7	0	0	0	0	0
1998	8	0	0	0	0	0
1998	9	0	0	0	0	0
1998	10	1	0	1	0	0
1998	11	0	1	0	1	0
1998	12	0	0	0	0	0
1999	1	0	0	0	0	1
1999	2	0	0	0	0	0
1999	3	0	0	0	0	0
1999	4	0	0	0	0	0
1999	5	0	0	0	0	0
1999	6	0	0	0	0	0
1999	7	0	0	0	0	0
1999	8	0	0	0	0	0
1999	9	0	0	0	0	0
1999	10	1	0	1	0	0
1999	11	0	1	0	1	0
1999	12	0	0	0	0	0
2000	1	0	0	0	0	1
2000	2	0	0	0	0	0
2000	3	0	0	0	0	0
2000	4	0	0	0	0	0
2000	5	0	0	0	0	0
2000	6	0	0	0	0	0
2000	7	0	0	0	0	0
2000	8	0	0	0	0	0
2000	9	0	0	0	0	0
2000	10	1	0	1	0	0
2000	11	0	1	0	1	0
2000	12	0	0	0	0	0
2001	1	0	0	0	0	1
2001	2	0	0	0	0	0
2001	3	0	0	0	0	0
2001	4	0	0	0	0	0
2001	5	0	0	0	0	0
2001	6	0	0	0	0	0
2001	7	0	0	0	0	0
2001	8	0	0	0	0	0
2001	9	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES

YEAR	MONTH	DA	DB	DM94AON	DM94BON	DM941ON
2001	10	1	0	1	0	0
2001	11	0	1	0	1	0
2001	12	0	0	0	0	0
2002	1	0	0	0	0	1
2002	2	0	0	0	0	0
2002	3	0	0	0	0	0
2002	4	0	0	0	0	0
2002	5	0	0	0	0	0
2002	6	0	0	0	0	0
2002	7	0	0	0	0	0
2002	8	0	0	0	0	0
2002	9	0	0	0	0	0
2002	10	1	0	1	0	0
2002	11	0	1	0	1	0
2002	12	0	0	0	0	0
2003	1	0	0	0	0	1
2003	2	0	0	0	0	0
2003	3	0	0	0	0	0
2003	4	0	0	0	0	0
2003	5	0	0	0	0	0
2003	6	0	0	0	0	0
2003	7	0	0	0	0	0
2003	8	0	0	0	0	0
2003	9	0	0	0	0	0
2003	10	1	0	1	0	0
2003	11	0	1	0	1	0
2003	12	0	0	0	0	0
2004	1	0	0	0	0	1
2004	2	0	0	0	0	0
2004	3	0	0	0	0	0
2004	4	0	0	0	0	0
2004	5	0	0	0	0	0
2004	6	0	0	0	0	0
2004	7	0	0	0	0	0
2004	8	0	0	0	0	0
2004	9	0	0	0	0	0
2004	10	1	0	1	0	0
2004	11	0	1	0	1	0
2004	12	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	DM9420N	DM9430N	DM9440N	DM9450N	DM9460N
1988	1	0	0	0	0	0
1988	2	0	0	0	0	0
1988	3	0	0	0	0	0
1988	4	0	0	0	0	0
1988	5	0	0	0	0	0
1988	6	0	0	0	0	0
1988	7	0	0	0	0	0
1988	8	0	0	0	0	0
1988	9	0	0	0	0	0
1988	10	0	0	0	0	0
1988	11	0	0	0	0	0
1988	12	0	0	0	0	0
1989	1	0	0	0	0	0
1989	2	0	0	0	0	0
1989	3	0	0	0	0	0
1989	4	0	0	0	0	0
1989	5	0	0	0	0	0
1989	6	0	0	0	0	0
1989	7	0	0	0	0	0
1989	8	0	0	0	0	0
1989	9	0	0	0	0	0
1989	10	0	0	0	0	0
1989	11	0	0	0	0	0
1989	12	0	0	0	0	0
1990	1	0	0	0	0	0
1990	2	0	0	0	0	0
1990	3	0	0	0	0	0
1990	4	0	0	0	0	0
1990	5	0	0	0	0	0
1990	6	0	0	0	0	0
1990	7	0	0	0	0	0
1990	8	0	0	0	0	0
1990	9	0	0	0	0	0
1990	10	0	0	0	0	0
1990	11	0	0	0	0	0
1990	12	0	0	0	0	0
1991	1	0	0	0	0	0
1991	2	0	0	0	0	0
1991	3	0	0	0	0	0
1991	4	0	0	0	0	0
1991	5	0	0	0	0	0
1991	6	0	0	0	0	0
1991	7	0	0	0	0	0
1991	8	0	0	0	0	0
1991	9	0	0	0	0	0
1991	10	0	0	0	0	0
1991	11	0	0	0	0	0
1991	12	0	0	0	0	0
1992	1	0	0	0	0	0
1992	2	0	0	0	0	0
1992	3	0	0	0	0	0
1992	4	0	0	0	0	0
1992	5	0	0	0	0	0
1992	6	0	0	0	0	0
1992	7	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	DM9420N	DM9430N	DM9440N	DM9450N	DM9460N
1992	8	0.00000	0	0	0	0
1992	9	0.00000	0	0	0	0
1992	10	0.00000	0	0	0	0
1992	11	0.00000	0	0	0	0
1992	12	0.00000	0	0	0	0
1993	1	0.00000	0	0	0	0
1993	2	0.00000	0	0	0	0
1993	3	0.00000	0	0	0	0
1993	4	0.00000	0	0	0	0
1993	5	0.00000	0	0	0	0
1993	6	0.00000	0	0	0	0
1993	7	0.00000	0	0	0	0
1993	8	0.00000	0	0	0	0
1993	9	0.00000	0	0	0	0
1993	10	0.00000	0	0	0	0
1993	11	0.00000	0	0	0	0
1993	12	0.00000	0	0	0	0
1994	1	0.00000	0	0	0	0
1994	2	1.00000	0	0	0	0
1994	3	0.00000	1	0	0	0
1994	4	0.00000	0	1	0	0
1994	5	0.00000	0	0	1	0
1994	6	0.00000	0	0	0	1
1994	7	0.00000	0	0	0	0
1994	8	0.00000	0	0	0	0
1994	9	0.00000	0	0	0	0
1994	10	0.00000	0	0	0	0
1994	11	0.00000	0	0	0	0
1994	12	0.00000	0	0	0	0
1995	1	0.00000	0	0	0	0
1995	2	1.00000	0	0	0	0
1995	3	0.00000	1	0	0	0
1995	4	0.00000	0	1	0	0
1995	5	0.00000	0	0	1	0
1995	6	0.00000	0	0	0	1
1995	7	0.00000	0	0	0	0
1995	8	0.00000	0	0	0	0
1995	9	0.00000	0	0	0	0
1995	10	0.00000	0	0	0	0
1995	11	0.00000	0	0	0	0
1995	12	0.00000	0	0	0	0
1996	1	0.00000	0	0	0	0
1996	2	1.03571	0	0	0	0
1996	3	0.00000	1	0	0	0
1996	4	0.00000	0	1	0	0
1996	5	0.00000	0	0	1	0
1996	6	0.00000	0	0	0	1
1996	7	0.00000	0	0	0	0
1996	8	0.00000	0	0	0	0
1996	9	0.00000	0	0	0	0
1996	10	0.00000	0	0	0	0
1996	11	0.00000	0	0	0	0
1996	12	0.00000	0	0	0	0
1997	1	0.00000	0	0	0	0
1997	2	1.00000	0	0	0	0

SHORT TERM MODELS 7
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	DM9420N	DM9430N	DM9440N	DM9450N	DM9460N
1997	3	0.00000	1	0	0	0
1997	4	0.00000	0	1	0	0
1997	5	0.00000	0	0	1	0
1997	6	0.00000	0	0	0	1
1997	7	0.00000	0	0	0	0
1997	8	0.00000	0	0	0	0
1997	9	0.00000	0	0	0	0
1997	10	0.00000	0	0	0	0
1997	11	0.00000	0	0	0	0
1997	12	0.00000	0	0	0	0
1998	1	0.00000	0	0	0	0
1998	2	1.00000	0	0	0	0
1998	3	0.00000	1	0	0	0
1998	4	0.00000	0	1	0	0
1998	5	0.00000	0	0	1	0
1998	6	0.00000	0	0	0	1
1998	7	0.00000	0	0	0	0
1998	8	0.00000	0	0	0	0
1998	9	0.00000	0	0	0	0
1998	10	0.00000	0	0	0	0
1998	11	0.00000	0	0	0	0
1998	12	0.00000	0	0	0	0
1999	1	0.00000	0	0	0	0
1999	2	1.00000	0	0	0	0
1999	3	0.00000	1	0	0	0
1999	4	0.00000	0	1	0	0
1999	5	0.00000	0	0	1	0
1999	6	0.00000	0	0	0	1
1999	7	0.00000	0	0	0	0
1999	8	0.00000	0	0	0	0
1999	9	0.00000	0	0	0	0
1999	10	0.00000	0	0	0	0
1999	11	0.00000	0	0	0	0
1999	12	0.00000	0	0	0	0
2000	1	0.00000	0	0	0	0
2000	2	1.03571	0	0	0	0
2000	3	0.00000	1	0	0	0
2000	4	0.00000	0	1	0	0
2000	5	0.00000	0	0	1	0
2000	6	0.00000	0	0	0	1
2000	7	0.00000	0	0	0	0
2000	8	0.00000	0	0	0	0
2000	9	0.00000	0	0	0	0
2000	10	0.00000	0	0	0	0
2000	11	0.00000	0	0	0	0
2000	12	0.00000	0	0	0	0
2001	1	0.00000	0	0	0	0
2001	2	1.00000	0	0	0	0
2001	3	0.00000	1	0	0	0
2001	4	0.00000	0	1	0	0
2001	5	0.00000	0	0	1	0
2001	6	0.00000	0	0	0	1
2001	7	0.00000	0	0	0	0
2001	8	0.00000	0	0	0	0
2001	9	0.00000	0	0	0	0

SHORT TERM MODELS 8
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	DM9420N	DM9430N	DM9440N	DM9450N	DM9460N
2001	10	0.00000	0	0	0	0
2001	11	0.00000	0	0	0	0
2001	12	0.00000	0	0	0	0
2002	1	0.00000	0	0	0	0
2002	2	1.00000	0	0	0	0
2002	3	0.00000	1	0	0	0
2002	4	0.00000	0	1	0	0
2002	5	0.00000	0	0	1	0
2002	6	0.00000	0	0	0	1
2002	7	0.00000	0	0	0	0
2002	8	0.00000	0	0	0	0
2002	9	0.00000	0	0	0	0
2002	10	0.00000	0	0	0	0
2002	11	0.00000	0	0	0	0
2002	12	0.00000	0	0	0	0
2003	1	0.00000	0	0	0	0
2003	2	1.00000	0	0	0	0
2003	3	0.00000	1	0	0	0
2003	4	0.00000	0	1	0	0
2003	5	0.00000	0	0	1	0
2003	6	0.00000	0	0	0	1
2003	7	0.00000	0	0	0	0
2003	8	0.00000	0	0	0	0
2003	9	0.00000	0	0	0	0
2003	10	0.00000	0	0	0	0
2003	11	0.00000	0	0	0	0
2003	12	0.00000	0	0	0	0
2004	1	0.00000	0	0	0	0
2004	2	1.03571	0	0	0	0
2004	3	0.00000	1	0	0	0
2004	4	0.00000	0	1	0	0
2004	5	0.00000	0	0	1	0
2004	6	0.00000	0	0	0	1
2004	7	0.00000	0	0	0	0
2004	8	0.00000	0	0	0	0
2004	9	0.00000	0	0	0	0
2004	10	0.00000	0	0	0	0
2004	11	0.00000	0	0	0	0
2004	12	0.00000	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	DM947ON	DM948ON	DM949ON	D1	D2
1988	1	0	0	0	1	0.00000
1988	2	0	0	0	0	1.03571
1988	3	0	0	0	0	0.00000
1988	4	0	0	0	0	0.00000
1988	5	0	0	0	0	0.00000
1988	6	0	0	0	0	0.00000
1988	7	0	0	0	0	0.00000
1988	8	0	0	0	0	0.00000
1988	9	0	0	0	0	0.00000
1988	10	0	0	0	0	0.00000
1988	11	0	0	0	0	0.00000
1988	12	0	0	0	0	0.00000
1989	1	0	0	0	1	0.00000
1989	2	0	0	0	0	1.00000
1989	3	0	0	0	0	0.00000
1989	4	0	0	0	0	0.00000
1989	5	0	0	0	0	0.00000
1989	6	0	0	0	0	0.00000
1989	7	0	0	0	0	0.00000
1989	8	0	0	0	0	0.00000
1989	9	0	0	0	0	0.00000
1989	10	0	0	0	0	0.00000
1989	11	0	0	0	0	0.00000
1989	12	0	0	0	0	0.00000
1990	1	0	0	0	1	0.00000
1990	2	0	0	0	0	1.00000
1990	3	0	0	0	0	0.00000
1990	4	0	0	0	0	0.00000
1990	5	0	0	0	0	0.00000
1990	6	0	0	0	0	0.00000
1990	7	0	0	0	0	0.00000
1990	8	0	0	0	0	0.00000
1990	9	0	0	0	0	0.00000
1990	10	0	0	0	0	0.00000
1990	11	0	0	0	0	0.00000
1990	12	0	0	0	0	0.00000
1991	1	0	0	0	1	0.00000
1991	2	0	0	0	0	1.00000
1991	3	0	0	0	0	0.00000
1991	4	0	0	0	0	0.00000
1991	5	0	0	0	0	0.00000
1991	6	0	0	0	0	0.00000
1991	7	0	0	0	0	0.00000
1991	8	0	0	0	0	0.00000
1991	9	0	0	0	0	0.00000
1991	10	0	0	0	0	0.00000
1991	11	0	0	0	0	0.00000
1991	12	0	0	0	0	0.00000
1992	1	0	0	0	1	0.00000
1992	2	0	0	0	0	1.03571
1992	3	0	0	0	0	0.00000
1992	4	0	0	0	0	0.00000
1992	5	0	0	0	0	0.00000
1992	6	0	0	0	0	0.00000
1992	7	0	0	0	0	0.00000

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	DM947ON	DM948ON	DM949ON	D1	D2
1992	8	0	0	0	0	0.00000
1992	9	0	0	0	0	0.00000
1992	10	0	0	0	0	0.00000
1992	11	0	0	0	0	0.00000
1992	12	0	0	0	0	0.00000
1993	1	0	0	0	1	0.00000
1993	2	0	0	0	0	1.00000
1993	3	0	0	0	0	0.00000
1993	4	0	0	0	0	0.00000
1993	5	0	0	0	0	0.00000
1993	6	0	0	0	0	0.00000
1993	7	0	0	0	0	0.00000
1993	8	0	0	0	0	0.00000
1993	9	0	0	0	0	0.00000
1993	10	0	0	0	0	0.00000
1993	11	0	0	0	0	0.00000
1993	12	0	0	0	0	0.00000
1994	1	0	0	0	1	0.00000
1994	2	0	0	0	0	1.00000
1994	3	0	0	0	0	0.00000
1994	4	0	0	0	0	0.00000
1994	5	0	0	0	0	0.00000
1994	6	0	0	0	0	0.00000
1994	7	1	0	0	0	0.00000
1994	8	0	1	0	0	0.00000
1994	9	0	0	1	0	0.00000
1994	10	0	0	0	0	0.00000
1994	11	0	0	0	0	0.00000
1994	12	0	0	0	0	0.00000
1995	1	0	0	0	1	0.00000
1995	2	0	0	0	0	1.00000
1995	3	0	0	0	0	0.00000
1995	4	0	0	0	0	0.00000
1995	5	0	0	0	0	0.00000
1995	6	0	0	0	0	0.00000
1995	7	1	0	0	0	0.00000
1995	8	0	1	0	0	0.00000
1995	9	0	0	1	0	0.00000
1995	10	0	0	0	0	0.00000
1995	11	0	0	0	0	0.00000
1995	12	0	0	0	0	0.00000
1996	1	0	0	0	1	0.00000
1996	2	0	0	0	0	1.03571
1996	3	0	0	0	0	0.00000
1996	4	0	0	0	0	0.00000
1996	5	0	0	0	0	0.00000
1996	6	0	0	0	0	0.00000
1996	7	1	0	0	0	0.00000
1996	8	0	1	0	0	0.00000
1996	9	0	0	1	0	0.00000
1996	10	0	0	0	0	0.00000
1996	11	0	0	0	0	0.00000
1996	12	0	0	0	0	0.00000
1997	1	0	0	0	1	0.00000
1997	2	0	0	0	0	1.00000

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	DM9470N	DM9480N	DM9490N	D1	D2
1997	3	0	0	0	0	0.00000
1997	4	0	0	0	0	0.00000
1997	5	0	0	0	0	0.00000
1997	6	0	0	0	0	0.00000
1997	7	1	0	0	0	0.00000
1997	8	0	1	0	0	0.00000
1997	9	0	0	1	0	0.00000
1997	10	0	0	0	0	0.00000
1997	11	0	0	0	0	0.00000
1997	12	0	0	0	0	0.00000
1998	1	0	0	0	1	0.00000
1998	2	0	0	0	0	1.00000
1998	3	0	0	0	0	0.00000
1998	4	0	0	0	0	0.00000
1998	5	0	0	0	0	0.00000
1998	6	0	0	0	0	0.00000
1998	7	1	0	0	0	0.00000
1998	8	0	1	0	0	0.00000
1998	9	0	0	1	0	0.00000
1998	10	0	0	0	0	0.00000
1998	11	0	0	0	0	0.00000
1998	12	0	0	0	0	0.00000
1999	1	0	0	0	1	0.00000
1999	2	0	0	0	0	1.00000
1999	3	0	0	0	0	0.00000
1999	4	0	0	0	0	0.00000
1999	5	0	0	0	0	0.00000
1999	6	0	0	0	0	0.00000
1999	7	1	0	0	0	0.00000
1999	8	0	1	0	0	0.00000
1999	9	0	0	1	0	0.00000
1999	10	0	0	0	0	0.00000
1999	11	0	0	0	0	0.00000
1999	12	0	0	0	0	0.00000
2000	1	0	0	0	1	0.00000
2000	2	0	0	0	0	1.03571
2000	3	0	0	0	0	0.00000
2000	4	0	0	0	0	0.00000
2000	5	0	0	0	0	0.00000
2000	6	0	0	0	0	0.00000
2000	7	1	0	0	0	0.00000
2000	8	0	1	0	0	0.00000
2000	9	0	0	1	0	0.00000
2000	10	0	0	0	0	0.00000
2000	11	0	0	0	0	0.00000
2000	12	0	0	0	0	0.00000
2001	1	0	0	0	1	0.00000
2001	2	0	0	0	0	1.00000
2001	3	0	0	0	0	0.00000
2001	4	0	0	0	0	0.00000
2001	5	0	0	0	0	0.00000
2001	6	0	0	0	0	0.00000
2001	7	1	0	0	0	0.00000
2001	8	0	1	0	0	0.00000
2001	9	0	0	1	0	0.00000

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	DM9470N	DM9480N	DM9490N	D1	D2
2001	10	0	0	0	0	0.00000
2001	11	0	0	0	0	0.00000
2001	12	0	0	0	0	0.00000
2002	1	0	0	0	1	0.00000
2002	2	0	0	0	0	1.00000
2002	3	0	0	0	0	0.00000
2002	4	0	0	0	0	0.00000
2002	5	0	0	0	0	0.00000
2002	6	0	0	0	0	0.00000
2002	7	1	0	0	0	0.00000
2002	8	0	1	0	0	0.00000
2002	9	0	0	1	0	0.00000
2002	10	0	0	0	0	0.00000
2002	11	0	0	0	0	0.00000
2002	12	0	0	0	0	0.00000
2003	1	0	0	0	1	0.00000
2003	2	0	0	0	0	1.00000
2003	3	0	0	0	0	0.00000
2003	4	0	0	0	0	0.00000
2003	5	0	0	0	0	0.00000
2003	6	0	0	0	0	0.00000
2003	7	1	0	0	0	0.00000
2003	8	0	1	0	0	0.00000
2003	9	0	0	1	0	0.00000
2003	10	0	0	0	0	0.00000
2003	11	0	0	0	0	0.00000
2003	12	0	0	0	0	0.00000
2004	1	0	0	0	1	0.00000
2004	2	0	0	0	0	1.03571
2004	3	0	0	0	0	0.00000
2004	4	0	0	0	0	0.00000
2004	5	0	0	0	0	0.00000
2004	6	0	0	0	0	0.00000
2004	7	1	0	0	0	0.00000
2004	8	0	1	0	0	0.00000
2004	9	0	0	1	0	0.00000
2004	10	0	0	0	0	0.00000
2004	11	0	0	0	0	0.00000
2004	12	0	0	0	0	0.00000

SHORT TERM MODELS 13
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D3	D4	D5	D6	D7
1988	1	0	0	0	0	0
1988	2	0	0	0	0	0
1988	3	1	0	0	0	0
1988	4	0	1	0	0	0
1988	5	0	0	1	0	0
1988	6	0	0	0	1	0
1988	7	0	0	0	0	1
1988	8	0	0	0	0	0
1988	9	0	0	0	0	0
1988	10	0	0	0	0	0
1988	11	0	0	0	0	0
1988	12	0	0	0	0	0
1989	1	0	0	0	0	0
1989	2	0	0	0	0	0
1989	3	1	0	0	0	0
1989	4	0	1	0	0	0
1989	5	0	0	1	0	0
1989	6	0	0	0	1	0
1989	7	0	0	0	0	1
1989	8	0	0	0	0	0
1989	9	0	0	0	0	0
1989	10	0	0	0	0	0
1989	11	0	0	0	0	0
1989	12	0	0	0	0	0
1990	1	0	0	0	0	0
1990	2	0	0	0	0	0
1990	3	1	0	0	0	0
1990	4	0	1	0	0	0
1990	5	0	0	1	0	0
1990	6	0	0	0	1	0
1990	7	0	0	0	0	1
1990	8	0	0	0	0	0
1990	9	0	0	0	0	0
1990	10	0	0	0	0	0
1990	11	0	0	0	0	0
1990	12	0	0	0	0	0
1991	1	0	0	0	0	0
1991	2	0	0	0	0	0
1991	3	1	0	0	0	0
1991	4	0	1	0	0	0
1991	5	0	0	1	0	0
1991	6	0	0	0	1	0
1991	7	0	0	0	0	1
1991	8	0	0	0	0	0
1991	9	0	0	0	0	0
1991	10	0	0	0	0	0
1991	11	0	0	0	0	0
1991	12	0	0	0	0	0
1992	1	0	0	0	0	0
1992	2	0	0	0	0	0
1992	3	1	0	0	0	0
1992	4	0	1	0	0	0
1992	5	0	0	1	0	0
1992	6	0	0	0	1	0
1992	7	0	0	0	0	1

SHORT TERM MODELS 14
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D3	D4	D5	D6	D7
1992	8	0	0	0	0	0
1992	9	0	0	0	0	0
1992	10	0	0	0	0	0
1992	11	0	0	0	0	0
1992	12	0	0	0	0	0
1993	1	0	0	0	0	0
1993	2	0	0	0	0	0
1993	3	1	0	0	0	0
1993	4	0	1	0	0	0
1993	5	0	0	1	0	0
1993	6	0	0	0	1	0
1993	7	0	0	0	0	1
1993	8	0	0	0	0	0
1993	9	0	0	0	0	0
1993	10	0	0	0	0	0
1993	11	0	0	0	0	0
1993	12	0	0	0	0	0
1994	1	0	0	0	0	0
1994	2	0	0	0	0	0
1994	3	1	0	0	0	0
1994	4	0	1	0	0	0
1994	5	0	0	1	0	0
1994	6	0	0	0	1	0
1994	7	0	0	0	0	1
1994	8	0	0	0	0	0
1994	9	0	0	0	0	0
1994	10	0	0	0	0	0
1994	11	0	0	0	0	0
1994	12	0	0	0	0	0
1995	1	0	0	0	0	0
1995	2	0	0	0	0	0
1995	3	1	0	0	0	0
1995	4	0	1	0	0	0
1995	5	0	0	1	0	0
1995	6	0	0	0	1	0
1995	7	0	0	0	0	1
1995	8	0	0	0	0	0
1995	9	0	0	0	0	0
1995	10	0	0	0	0	0
1995	11	0	0	0	0	0
1995	12	0	0	0	0	0
1996	1	0	0	0	0	0
1996	2	0	0	0	0	0
1996	3	1	0	0	0	0
1996	4	0	1	0	0	0
1996	5	0	0	1	0	0
1996	6	0	0	0	1	0
1996	7	0	0	0	0	1
1996	8	0	0	0	0	0
1996	9	0	0	0	0	0
1996	10	0	0	0	0	0
1996	11	0	0	0	0	0
1996	12	0	0	0	0	0
1997	1	0	0	0	0	0
1997	2	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D3	D4	D5	D6	D7
1997	3	1	0	0	0	0
1997	4	0	1	0	0	0
1997	5	0	0	1	0	0
1997	6	0	0	0	1	0
1997	7	0	0	0	0	1
1997	8	0	0	0	0	0
1997	9	0	0	0	0	0
1997	10	0	0	0	0	0
1997	11	0	0	0	0	0
1997	12	0	0	0	0	0
1998	1	0	0	0	0	0
1998	2	0	0	0	0	0
1998	3	1	0	0	0	0
1998	4	0	1	0	0	0
1998	5	0	0	1	0	0
1998	6	0	0	0	1	0
1998	7	0	0	0	0	1
1998	8	0	0	0	0	0
1998	9	0	0	0	0	0
1998	10	0	0	0	0	0
1998	11	0	0	0	0	0
1998	12	0	0	0	0	0
1999	1	0	0	0	0	0
1999	2	0	0	0	0	0
1999	3	1	0	0	0	0
1999	4	0	1	0	0	0
1999	5	0	0	1	0	0
1999	6	0	0	0	1	0
1999	7	0	0	0	0	1
1999	8	0	0	0	0	0
1999	9	0	0	0	0	0
1999	10	0	0	0	0	0
1999	11	0	0	0	0	0
1999	12	0	0	0	0	0
2000	1	0	0	0	0	0
2000	2	0	0	0	0	0
2000	3	1	0	0	0	0
2000	4	0	1	0	0	0
2000	5	0	0	1	0	0
2000	6	0	0	0	1	0
2000	7	0	0	0	0	1
2000	8	0	0	0	0	0
2000	9	0	0	0	0	0
2000	10	0	0	0	0	0
2000	11	0	0	0	0	0
2000	12	0	0	0	0	0
2001	1	0	0	0	0	0
2001	2	0	0	0	0	0
2001	3	1	0	0	0	0
2001	4	0	1	0	0	0
2001	5	0	0	1	0	0
2001	6	0	0	0	1	0
2001	7	0	0	0	0	1
2001	8	0	0	0	0	0
2001	9	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D3	D4	D5	D6	D7
2001	10	0	0	0	0	0
2001	11	0	0	0	0	0
2001	12	0	0	0	0	0
2002	1	0	0	0	0	0
2002	2	0	0	0	0	0
2002	3	1	0	0	0	0
2002	4	0	1	0	0	0
2002	5	0	0	1	0	0
2002	6	0	0	0	1	0
2002	7	0	0	0	0	1
2002	8	0	0	0	0	0
2002	9	0	0	0	0	0
2002	10	0	0	0	0	0
2002	11	0	0	0	0	0
2002	12	0	0	0	0	0
2003	1	0	0	0	0	0
2003	2	0	0	0	0	0
2003	3	1	0	0	0	0
2003	4	0	1	0	0	0
2003	5	0	0	1	0	0
2003	6	0	0	0	1	0
2003	7	0	0	0	0	1
2003	8	0	0	0	0	0
2003	9	0	0	0	0	0
2003	10	0	0	0	0	0
2003	11	0	0	0	0	0
2003	12	0	0	0	0	0
2004	1	0	0	0	0	0
2004	2	0	0	0	0	0
2004	3	1	0	0	0	0
2004	4	0	1	0	0	0
2004	5	0	0	1	0	0
2004	6	0	0	0	1	0
2004	7	0	0	0	0	1
2004	8	0	0	0	0	0
2004	9	0	0	0	0	0
2004	10	0	0	0	0	0
2004	11	0	0	0	0	0
2004	12	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D8	D894896	D8990N	D9	D90A914
1988	1	0	0	0.00000	0	0
1988	2	0	0	0.00000	0	0
1988	3	0	0	0.00000	0	0
1988	4	0	0	0.00000	0	0
1988	5	0	0	0.00000	0	0
1988	6	0	0	0.00000	0	0
1988	7	0	0	0.00000	0	0
1988	8	1	0	0.00000	0	0
1988	9	0	0	0.00000	1	0
1988	10	0	0	0.00000	0	0
1988	11	0	0	0.00000	0	0
1988	12	0	0	0.00000	0	0
1989	1	0	0	0.00000	0	0
1989	2	0	0	0.00000	0	0
1989	3	0	0	0.00000	0	0
1989	4	0	1	0.00000	0	0
1989	5	0	1	0.00000	0	0
1989	6	0	1	0.00000	0	0
1989	7	0	0	0.00000	0	0
1989	8	1	0	0.00000	0	0
1989	9	0	0	1.00000	1	0
1989	10	0	0	1.00000	0	0
1989	11	0	0	1.00000	0	0
1989	12	0	0	1.00000	0	0
1990	1	0	0	1.00000	0	0
1990	2	0	0	1.00000	0	0
1990	3	0	0	1.00000	0	0
1990	4	0	0	1.00000	0	0
1990	5	0	0	1.00000	0	0
1990	6	0	0	1.00000	0	0
1990	7	0	0	1.00000	0	0
1990	8	1	0	1.00000	0	0
1990	9	0	0	1.00000	1	0
1990	10	0	0	1.00000	0	1
1990	11	0	0	1.00000	0	1
1990	12	0	0	1.00000	0	1
1991	1	0	0	1.00000	0	1
1991	2	0	0	1.00000	0	1
1991	3	0	0	1.00000	0	1
1991	4	0	0	1.00000	0	1
1991	5	0	0	1.00000	0	0
1991	6	0	0	1.00000	0	0
1991	7	0	0	1.00000	0	0
1991	8	1	0	1.00000	0	0
1991	9	0	0	1.00000	1	0
1991	10	0	0	1.00000	0	0
1991	11	0	0	1.00000	0	0
1991	12	0	0	1.00000	0	0
1992	1	0	0	1.00000	0	0
1992	2	0	0	1.03571	0	0
1992	3	0	0	1.00000	0	0
1992	4	0	0	1.00000	0	0
1992	5	0	0	1.00000	0	0
1992	6	0	0	1.00000	0	0
1992	7	0	0	1.00000	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D8	D894896	D8990N	D9	D90A914
1992	8	1	0	1.00000	0	0
1992	9	0	0	1.00000	1	0
1992	10	0	0	1.00000	0	0
1992	11	0	0	1.00000	0	0
1992	12	0	0	1.00000	0	0
1993	1	0	0	1.00000	0	0
1993	2	0	0	1.00000	0	0
1993	3	0	0	1.00000	0	0
1993	4	0	0	1.00000	0	0
1993	5	0	0	1.00000	0	0
1993	6	0	0	1.00000	0	0
1993	7	0	0	1.00000	0	0
1993	8	1	0	1.00000	0	0
1993	9	0	0	1.00000	1	0
1993	10	0	0	1.00000	0	0
1993	11	0	0	1.00000	0	0
1993	12	0	0	1.00000	0	0
1994	1	0	0	1.00000	0	0
1994	2	0	0	1.00000	0	0
1994	3	0	0	1.00000	0	0
1994	4	0	0	1.00000	0	0
1994	5	0	0	1.00000	0	0
1994	6	0	0	1.00000	0	0
1994	7	0	0	1.00000	0	0
1994	8	1	0	1.00000	0	0
1994	9	0	0	1.00000	1	0
1994	10	0	0	1.00000	0	0
1994	11	0	0	1.00000	0	0
1994	12	0	0	1.00000	0	0
1995	1	0	0	1.00000	0	0
1995	2	0	0	1.00000	0	0
1995	3	0	0	1.00000	0	0
1995	4	0	0	1.00000	0	0
1995	5	0	0	1.00000	0	0
1995	6	0	0	1.00000	0	0
1995	7	0	0	1.00000	0	0
1995	8	1	0	1.00000	0	0
1995	9	0	0	1.00000	1	0
1995	10	0	0	1.00000	0	0
1995	11	0	0	1.00000	0	0
1995	12	0	0	1.00000	0	0
1996	1	0	0	1.00000	0	0
1996	2	0	0	1.03571	0	0
1996	3	0	0	1.00000	0	0
1996	4	0	0	1.00000	0	0
1996	5	0	0	1.00000	0	0
1996	6	0	0	1.00000	0	0
1996	7	0	0	1.00000	0	0
1996	8	1	0	1.00000	0	0
1996	9	0	0	1.00000	1	0
1996	10	0	0	1.00000	0	0
1996	11	0	0	1.00000	0	0
1996	12	0	0	1.00000	0	0
1997	1	0	0	1.00000	0	0
1997	2	0	0	1.00000	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D8	D894896	D8990N	D9	D90A914
1997	3	0	0	1.00000	0	0
1997	4	0	0	1.00000	0	0
1997	5	0	0	1.00000	0	0
1997	6	0	0	1.00000	0	0
1997	7	0	0	1.00000	0	0
1997	8	1	0	1.00000	0	0
1997	9	0	0	1.00000	1	0
1997	10	0	0	1.00000	0	0
1997	11	0	0	1.00000	0	0
1997	12	0	0	1.00000	0	0
1998	1	0	0	1.00000	0	0
1998	2	0	0	1.00000	0	0
1998	3	0	0	1.00000	0	0
1998	4	0	0	1.00000	0	0
1998	5	0	0	1.00000	0	0
1998	6	0	0	1.00000	0	0
1998	7	0	0	1.00000	0	0
1998	8	1	0	1.00000	0	0
1998	9	0	0	1.00000	1	0
1998	10	0	0	1.00000	0	0
1998	11	0	0	1.00000	0	0
1998	12	0	0	1.00000	0	0
1999	1	0	0	1.00000	0	0
1999	2	0	0	1.00000	0	0
1999	3	0	0	1.00000	0	0
1999	4	0	0	1.00000	0	0
1999	5	0	0	1.00000	0	0
1999	6	0	0	1.00000	0	0
1999	7	0	0	1.00000	0	0
1999	8	1	0	1.00000	0	0
1999	9	0	0	1.00000	1	0
1999	10	0	0	1.00000	0	0
1999	11	0	0	1.00000	0	0
1999	12	0	0	1.00000	0	0
2000	1	0	0	1.00000	0	0
2000	2	0	0	1.03571	0	0
2000	3	0	0	1.00000	0	0
2000	4	0	0	1.00000	0	0
2000	5	0	0	1.00000	0	0
2000	6	0	0	1.00000	0	0
2000	7	0	0	1.00000	0	0
2000	8	1	0	1.00000	0	0
2000	9	0	0	1.00000	1	0
2000	10	0	0	1.00000	0	0
2000	11	0	0	1.00000	0	0
2000	12	0	0	1.00000	0	0
2001	1	0	0	1.00000	0	0
2001	2	0	0	1.00000	0	0
2001	3	0	0	1.00000	0	0
2001	4	0	0	1.00000	0	0
2001	5	0	0	1.00000	0	0
2001	6	0	0	1.00000	0	0
2001	7	0	0	1.00000	0	0
2001	8	1	0	1.00000	0	0
2001	9	0	0	1.00000	1	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D8	D894896	D8990N	D9	D90A914
2001	10	0	0	1.00000	0	0
2001	11	0	0	1.00000	0	0
2001	12	0	0	1.00000	0	0
2002	1	0	0	1.00000	0	0
2002	2	0	0	1.00000	0	0
2002	3	0	0	1.00000	0	0
2002	4	0	0	1.00000	0	0
2002	5	0	0	1.00000	0	0
2002	6	0	0	1.00000	0	0
2002	7	0	0	1.00000	0	0
2002	8	1	0	1.00000	0	0
2002	9	0	0	1.00000	1	0
2002	10	0	0	1.00000	0	0
2002	11	0	0	1.00000	0	0
2002	12	0	0	1.00000	0	0
2003	1	0	0	1.00000	0	0
2003	2	0	0	1.00000	0	0
2003	3	0	0	1.00000	0	0
2003	4	0	0	1.00000	0	0
2003	5	0	0	1.00000	0	0
2003	6	0	0	1.00000	0	0
2003	7	0	0	1.00000	0	0
2003	8	1	0	1.00000	0	0
2003	9	0	0	1.00000	1	0
2003	10	0	0	1.00000	0	0
2003	11	0	0	1.00000	0	0
2003	12	0	0	1.00000	0	0
2004	1	0	0	1.00000	0	0
2004	2	0	0	1.03571	0	0
2004	3	0	0	1.00000	0	0
2004	4	0	0	1.00000	0	0
2004	5	0	0	1.00000	0	0
2004	6	0	0	1.00000	0	0
2004	7	0	0	1.00000	0	0
2004	8	1	0	1.00000	0	0
2004	9	0	0	1.00000	1	0
2004	10	0	0	1.00000	0	0
2004	11	0	0	1.00000	0	0
2004	12	0	0	1.00000	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D911	D92292A	D927947	D9410N	D94294C
1988	1	0	0.00000	0	0	0
1988	2	0	0.00000	0	0	0
1988	3	0	0.00000	0	0	0
1988	4	0	0.00000	0	0	0
1988	5	0	0.00000	0	0	0
1988	6	0	0.00000	0	0	0
1988	7	0	0.00000	0	0	0
1988	8	0	0.00000	0	0	0
1988	9	0	0.00000	0	0	0
1988	10	0	0.00000	0	0	0
1988	11	0	0.00000	0	0	0
1988	12	0	0.00000	0	0	0
1989	1	0	0.00000	0	0	0
1989	2	0	0.00000	0	0	0
1989	3	0	0.00000	0	0	0
1989	4	0	0.00000	0	0	0
1989	5	0	0.00000	0	0	0
1989	6	0	0.00000	0	0	0
1989	7	0	0.00000	0	0	0
1989	8	0	0.00000	0	0	0
1989	9	0	0.00000	0	0	0
1989	10	0	0.00000	0	0	0
1989	11	0	0.00000	0	0	0
1989	12	0	0.00000	0	0	0
1990	1	0	0.00000	0	0	0
1990	2	0	0.00000	0	0	0
1990	3	0	0.00000	0	0	0
1990	4	0	0.00000	0	0	0
1990	5	0	0.00000	0	0	0
1990	6	0	0.00000	0	0	0
1990	7	0	0.00000	0	0	0
1990	8	0	0.00000	0	0	0
1990	9	0	0.00000	0	0	0
1990	10	0	0.00000	0	0	0
1990	11	0	0.00000	0	0	0
1990	12	0	0.00000	0	0	0
1991	1	1	0.00000	0	0	0
1991	2	0	0.00000	0	0	0
1991	3	0	0.00000	0	0	0
1991	4	0	0.00000	0	0	0
1991	5	0	0.00000	0	0	0
1991	6	0	0.00000	0	0	0
1991	7	0	0.00000	0	0	0
1991	8	0	0.00000	0	0	0
1991	9	0	0.00000	0	0	0
1991	10	0	0.00000	0	0	0
1991	11	0	0.00000	0	0	0
1991	12	0	0.00000	0	0	0
1992	1	0	0.00000	0	0	0
1992	2	0	1.03571	0	0	0
1992	3	0	1.00000	0	0	0
1992	4	0	1.00000	0	0	0
1992	5	0	1.00000	0	0	0
1992	6	0	1.00000	0	0	0
1992	7	0	1.00000	1	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D911	D92292A	D927947	D9410N	D94294C
1992	8	0	1	1	0.00000	0
1992	9	0	1	1	0.00000	0
1992	10	0	1	1	0.00000	0
1992	11	0	0	1	0.00000	0
1992	12	0	0	1	0.00000	0
1993	1	0	0	1	0.00000	0
1993	2	0	0	1	0.00000	0
1993	3	0	0	1	0.00000	0
1993	4	0	0	1	0.00000	0
1993	5	0	0	1	0.00000	0
1993	6	0	0	1	0.00000	0
1993	7	0	0	1	0.00000	0
1993	8	0	0	1	0.00000	0
1993	9	0	0	1	0.00000	0
1993	10	0	0	1	0.00000	0
1993	11	0	0	1	0.00000	0
1993	12	0	0	1	0.00000	0
1994	1	0	0	1	1.00000	0
1994	2	0	0	1	1.00000	1
1994	3	0	0	1	1.00000	1
1994	4	0	0	1	1.00000	1
1994	5	0	0	1	1.00000	1
1994	6	0	0	1	1.00000	1
1994	7	0	0	1	1.00000	1
1994	8	0	0	0	1.00000	1
1994	9	0	0	0	1.00000	1
1994	10	0	0	0	1.00000	1
1994	11	0	0	0	1.00000	1
1994	12	0	0	0	1.00000	1
1995	1	0	0	0	1.00000	0
1995	2	0	0	0	1.00000	0
1995	3	0	0	0	1.00000	0
1995	4	0	0	0	1.00000	0
1995	5	0	0	0	1.00000	0
1995	6	0	0	0	1.00000	0
1995	7	0	0	0	1.00000	0
1995	8	0	0	0	1.00000	0
1995	9	0	0	0	1.00000	0
1995	10	0	0	0	1.00000	0
1995	11	0	0	0	1.00000	0
1995	12	0	0	0	1.00000	0
1996	1	0	0	0	1.00000	0
1996	2	0	0	0	1.03571	0
1996	3	0	0	0	1.00000	0
1996	4	0	0	0	1.00000	0
1996	5	0	0	0	1.00000	0
1996	6	0	0	0	1.00000	0
1996	7	0	0	0	1.00000	0
1996	8	0	0	0	1.00000	0
1996	9	0	0	0	1.00000	0
1996	10	0	0	0	1.00000	0
1996	11	0	0	0	1.00000	0
1996	12	0	0	0	1.00000	0
1997	1	0	0	0	1.00000	0
1997	2	0	0	0	1.00000	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

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YEAR	MONTH	D911	D92292A	D927947	D9410N	D94294C
1997	3	0	0	0	1.00000	0
1997	4	0	0	0	1.00000	0
1997	5	0	0	0	1.00000	0
1997	6	0	0	0	1.00000	0
1997	7	0	0	0	1.00000	0
1997	8	0	0	0	1.00000	0
1997	9	0	0	0	1.00000	0
1997	10	0	0	0	1.00000	0
1997	11	0	0	0	1.00000	0
1997	12	0	0	0	1.00000	0
1998	1	0	0	0	1.00000	0
1998	2	0	0	0	1.00000	0
1998	3	0	0	0	1.00000	0
1998	4	0	0	0	1.00000	0
1998	5	0	0	0	1.00000	0
1998	6	0	0	0	1.00000	0
1998	7	0	0	0	1.00000	0
1998	8	0	0	0	1.00000	0
1998	9	0	0	0	1.00000	0
1998	10	0	0	0	1.00000	0
1998	11	0	0	0	1.00000	0
1998	12	0	0	0	1.00000	0
1999	1	0	0	0	1.00000	0
1999	2	0	0	0	1.00000	0
1999	3	0	0	0	1.00000	0
1999	4	0	0	0	1.00000	0
1999	5	0	0	0	1.00000	0
1999	6	0	0	0	1.00000	0
1999	7	0	0	0	1.00000	0
1999	8	0	0	0	1.00000	0
1999	9	0	0	0	1.00000	0
1999	10	0	0	0	1.00000	0
1999	11	0	0	0	1.00000	0
1999	12	0	0	0	1.00000	0
2000	1	0	0	0	1.00000	0
2000	2	0	0	0	1.03571	0
2000	3	0	0	0	1.00000	0
2000	4	0	0	0	1.00000	0
2000	5	0	0	0	1.00000	0
2000	6	0	0	0	1.00000	0
2000	7	0	0	0	1.00000	0
2000	8	0	0	0	1.00000	0
2000	9	0	0	0	1.00000	0
2000	10	0	0	0	1.00000	0
2000	11	0	0	0	1.00000	0
2000	12	0	0	0	1.00000	0
2001	1	0	0	0	1.00000	0
2001	2	0	0	0	1.00000	0
2001	3	0	0	0	1.00000	0
2001	4	0	0	0	1.00000	0
2001	5	0	0	0	1.00000	0
2001	6	0	0	0	1.00000	0
2001	7	0	0	0	1.00000	0
2001	8	0	0	0	1.00000	0
2001	9	0	0	0	1.00000	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

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YEAR	MONTH	D911	D92292A	D927947	D9410N	D94294C
2001	10	0	0	0	1.00000	0
2001	11	0	0	0	1.00000	0
2001	12	0	0	0	1.00000	0
2002	1	0	0	0	1.00000	0
2002	2	0	0	0	1.00000	0
2002	3	0	0	0	1.00000	0
2002	4	0	0	0	1.00000	0
2002	5	0	0	0	1.00000	0
2002	6	0	0	0	1.00000	0
2002	7	0	0	0	1.00000	0
2002	8	0	0	0	1.00000	0
2002	9	0	0	0	1.00000	0
2002	10	0	0	0	1.00000	0
2002	11	0	0	0	1.00000	0
2002	12	0	0	0	1.00000	0
2003	1	0	0	0	1.00000	0
2003	2	0	0	0	1.00000	0
2003	3	0	0	0	1.00000	0
2003	4	0	0	0	1.00000	0
2003	5	0	0	0	1.00000	0
2003	6	0	0	0	1.00000	0
2003	7	0	0	0	1.00000	0
2003	8	0	0	0	1.00000	0
2003	9	0	0	0	1.00000	0
2003	10	0	0	0	1.00000	0
2003	11	0	0	0	1.00000	0
2003	12	0	0	0	1.00000	0
2004	1	0	0	0	1.00000	0
2004	2	0	0	0	1.03571	0
2004	3	0	0	0	1.00000	0
2004	4	0	0	0	1.00000	0
2004	5	0	0	0	1.00000	0
2004	6	0	0	0	1.00000	0
2004	7	0	0	0	1.00000	0
2004	8	0	0	0	1.00000	0
2004	9	0	0	0	1.00000	0
2004	10	0	0	0	1.00000	0
2004	11	0	0	0	1.00000	0
2004	12	0	0	0	1.00000	0

SHORT TERM MODELS

BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D95C	D95SON	D956ON	D961	D961967
1988	1	0	0	0	0	0
1988	2	0	0	0	0	0
1988	3	0	0	0	0	0
1988	4	0	0	0	0	0
1988	5	0	0	0	0	0
1988	6	0	0	0	0	0
1988	7	0	0	0	0	0
1988	8	0	0	0	0	0
1988	9	0	0	0	0	0
1988	10	0	0	0	0	0
1988	11	0	0	0	0	0
1988	12	0	0	0	0	0
1989	1	0	0	0	0	0
1989	2	0	0	0	0	0
1989	3	0	0	0	0	0
1989	4	0	0	0	0	0
1989	5	0	0	0	0	0
1989	6	0	0	0	0	0
1989	7	0	0	0	0	0
1989	8	0	0	0	0	0
1989	9	0	0	0	0	0
1989	10	0	0	0	0	0
1989	11	0	0	0	0	0
1989	12	0	0	0	0	0
1990	1	0	0	0	0	0
1990	2	0	0	0	0	0
1990	3	0	0	0	0	0
1990	4	0	0	0	0	0
1990	5	0	0	0	0	0
1990	6	0	0	0	0	0
1990	7	0	0	0	0	0
1990	8	0	0	0	0	0
1990	9	0	0	0	0	0
1990	10	0	0	0	0	0
1990	11	0	0	0	0	0
1990	12	0	0	0	0	0
1991	1	0	0	0	0	0
1991	2	0	0	0	0	0
1991	3	0	0	0	0	0
1991	4	0	0	0	0	0
1991	5	0	0	0	0	0
1991	6	0	0	0	0	0
1991	7	0	0	0	0	0
1991	8	0	0	0	0	0
1991	9	0	0	0	0	0
1991	10	0	0	0	0	0
1991	11	0	0	0	0	0
1991	12	0	0	0	0	0
1992	1	0	0	0	0	0
1992	2	0	0	0	0	0
1992	3	0	0	0	0	0
1992	4	0	0	0	0	0
1992	5	0	0	0	0	0
1992	6	0	0	0	0	0
1992	7	0	0	0	0	0

SHORT TERM MODELS

BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D95C	D95SON	D956ON	D961	D961967
1992	8	0	0.00000	0.00000	0	0.00000
1992	9	0	0.00000	0.00000	0	0.00000
1992	10	0	0.00000	0.00000	0	0.00000
1992	11	0	0.00000	0.00000	0	0.00000
1992	12	0	0.00000	0.00000	0	0.00000
1993	1	0	0.00000	0.00000	0	0.00000
1993	2	0	0.00000	0.00000	0	0.00000
1993	3	0	0.00000	0.00000	0	0.00000
1993	4	0	0.00000	0.00000	0	0.00000
1993	5	0	0.00000	0.00000	0	0.00000
1993	6	0	0.00000	0.00000	0	0.00000
1993	7	0	0.00000	0.00000	0	0.00000
1993	8	0	0.00000	0.00000	0	0.00000
1993	9	0	0.00000	0.00000	0	0.00000
1993	10	0	0.00000	0.00000	0	0.00000
1993	11	0	0.00000	0.00000	0	0.00000
1993	12	0	0.00000	0.00000	0	0.00000
1994	1	0	0.00000	0.00000	0	0.00000
1994	2	0	0.00000	0.00000	0	0.00000
1994	3	0	0.00000	0.00000	0	0.00000
1994	4	0	0.00000	0.00000	0	0.00000
1994	5	0	0.00000	0.00000	0	0.00000
1994	6	0	0.00000	0.00000	0	0.00000
1994	7	0	0.00000	0.00000	0	0.00000
1994	8	0	0.00000	0.00000	0	0.00000
1994	9	0	0.00000	0.00000	0	0.00000
1994	10	0	0.00000	0.00000	0	0.00000
1994	11	0	0.00000	0.00000	0	0.00000
1994	12	0	0.00000	0.00000	0	0.00000
1995	1	0	0.00000	0.00000	0	0.00000
1995	2	0	0.00000	0.00000	0	0.00000
1995	3	0	0.00000	0.00000	0	0.00000
1995	4	0	0.00000	0.00000	0	0.00000
1995	5	0	1.00000	0.00000	0	0.00000
1995	6	0	1.00000	1.00000	0	0.00000
1995	7	0	1.00000	1.00000	0	0.00000
1995	8	0	1.00000	1.00000	0	0.00000
1995	9	0	1.00000	1.00000	0	0.00000
1995	10	0	1.00000	1.00000	0	0.00000
1995	11	0	1.00000	1.00000	0	0.00000
1995	12	1	1.00000	1.00000	0	0.00000
1996	1	0	1.00000	1.00000	1	1.00000
1996	2	0	1.03571	1.03571	0	1.03571
1996	3	0	1.00000	1.00000	0	1.00000
1996	4	0	1.00000	1.00000	0	1.00000
1996	5	0	1.00000	1.00000	0	1.00000
1996	6	0	1.00000	1.00000	0	1.00000
1996	7	0	1.00000	1.00000	0	1.00000
1996	8	0	1.00000	1.00000	0	0.00000
1996	9	0	1.00000	1.00000	0	0.00000
1996	10	0	1.00000	1.00000	0	0.00000
1996	11	0	1.00000	1.00000	0	0.00000
1996	12	0	1.00000	1.00000	0	0.00000
1997	1	0	1.00000	1.00000	0	0.00000
1997	2	0	1.00000	1.00000	0	0.00000

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

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YEAR	MONTH	D9SC	D955ON	D956ON	D961	D961967
1997	3	0	1.00000	1.00000	0	0
1997	4	0	1.00000	1.00000	0	0
1997	5	0	1.00000	1.00000	0	0
1997	6	0	1.00000	1.00000	0	0
1997	7	0	1.00000	1.00000	0	0
1997	8	0	1.00000	1.00000	0	0
1997	9	0	1.00000	1.00000	0	0
1997	10	0	1.00000	1.00000	0	0
1997	11	0	1.00000	1.00000	0	0
1997	12	0	1.00000	1.00000	0	0
1998	1	0	1.00000	1.00000	0	0
1998	2	0	1.00000	1.00000	0	0
1998	3	0	1.00000	1.00000	0	0
1998	4	0	1.00000	1.00000	0	0
1998	5	0	1.00000	1.00000	0	0
1998	6	0	1.00000	1.00000	0	0
1998	7	0	1.00000	1.00000	0	0
1998	8	0	1.00000	1.00000	0	0
1998	9	0	1.00000	1.00000	0	0
1998	10	0	1.00000	1.00000	0	0
1998	11	0	1.00000	1.00000	0	0
1998	12	0	1.00000	1.00000	0	0
1999	1	0	1.00000	1.00000	0	0
1999	2	0	1.00000	1.00000	0	0
1999	3	0	1.00000	1.00000	0	0
1999	4	0	1.00000	1.00000	0	0
1999	5	0	1.00000	1.00000	0	0
1999	6	0	1.00000	1.00000	0	0
1999	7	0	1.00000	1.00000	0	0
1999	8	0	1.00000	1.00000	0	0
1999	9	0	1.00000	1.00000	0	0
1999	10	0	1.00000	1.00000	0	0
1999	11	0	1.00000	1.00000	0	0
1999	12	0	1.00000	1.00000	0	0
2000	1	0	1.00000	1.00000	0	0
2000	2	0	1.03571	1.03571	0	0
2000	3	0	1.00000	1.00000	0	0
2000	4	0	1.00000	1.00000	0	0
2000	5	0	1.00000	1.00000	0	0
2000	6	0	1.00000	1.00000	0	0
2000	7	0	1.00000	1.00000	0	0
2000	8	0	1.00000	1.00000	0	0
2000	9	0	1.00000	1.00000	0	0
2000	10	0	1.00000	1.00000	0	0
2000	11	0	1.00000	1.00000	0	0
2000	12	0	1.00000	1.00000	0	0
2001	1	0	1.00000	1.00000	0	0
2001	2	0	1.00000	1.00000	0	0
2001	3	0	1.00000	1.00000	0	0
2001	4	0	1.00000	1.00000	0	0
2001	5	0	1.00000	1.00000	0	0
2001	6	0	1.00000	1.00000	0	0
2001	7	0	1.00000	1.00000	0	0
2001	8	0	1.00000	1.00000	0	0
2001	9	0	1.00000	1.00000	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

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YEAR	MONTH	D9SC	D955ON	D956ON	D961	D961967
2001	10	0	1.00000	1.00000	0	0
2001	11	0	1.00000	1.00000	0	0
2001	12	0	1.00000	1.00000	0	0
2002	1	0	1.00000	1.00000	0	0
2002	2	0	1.00000	1.00000	0	0
2002	3	0	1.00000	1.00000	0	0
2002	4	0	1.00000	1.00000	0	0
2002	5	0	1.00000	1.00000	0	0
2002	6	0	1.00000	1.00000	0	0
2002	7	0	1.00000	1.00000	0	0
2002	8	0	1.00000	1.00000	0	0
2002	9	0	1.00000	1.00000	0	0
2002	10	0	1.00000	1.00000	0	0
2002	11	0	1.00000	1.00000	0	0
2002	12	0	1.00000	1.00000	0	0
2003	1	0	1.00000	1.00000	0	0
2003	2	0	1.00000	1.00000	0	0
2003	3	0	1.00000	1.00000	0	0
2003	4	0	1.00000	1.00000	0	0
2003	5	0	1.00000	1.00000	0	0
2003	6	0	1.00000	1.00000	0	0
2003	7	0	1.00000	1.00000	0	0
2003	8	0	1.00000	1.00000	0	0
2003	9	0	1.00000	1.00000	0	0
2003	10	0	1.00000	1.00000	0	0
2003	11	0	1.00000	1.00000	0	0
2003	12	0	1.00000	1.00000	0	0
2004	1	0	1.00000	1.00000	0	0
2004	2	0	1.03571	1.03571	0	0
2004	3	0	1.00000	1.00000	0	0
2004	4	0	1.00000	1.00000	0	0
2004	5	0	1.00000	1.00000	0	0
2004	6	0	1.00000	1.00000	0	0
2004	7	0	1.00000	1.00000	0	0
2004	8	0	1.00000	1.00000	0	0
2004	9	0	1.00000	1.00000	0	0
2004	10	0	1.00000	1.00000	0	0
2004	11	0	1.00000	1.00000	0	0
2004	12	0	1.00000	1.00000	0	0

SHORT TERM MODELS 29
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D962	D963	D967971	D97B	D971ON
1988	1	0	0	0	0	0
1988	2	0	0	0	0	0
1988	3	0	0	0	0	0
1988	4	0	0	0	0	0
1988	5	0	0	0	0	0
1988	6	0	0	0	0	0
1988	7	0	0	0	0	0
1988	8	0	0	0	0	0
1988	9	0	0	0	0	0
1988	10	0	0	0	0	0
1988	11	0	0	0	0	0
1988	12	0	0	0	0	0
1989	1	0	0	0	0	0
1989	2	0	0	0	0	0
1989	3	0	0	0	0	0
1989	4	0	0	0	0	0
1989	5	0	0	0	0	0
1989	6	0	0	0	0	0
1989	7	0	0	0	0	0
1989	8	0	0	0	0	0
1989	9	0	0	0	0	0
1989	10	0	0	0	0	0
1989	11	0	0	0	0	0
1989	12	0	0	0	0	0
1990	1	0	0	0	0	0
1990	2	0	0	0	0	0
1990	3	0	0	0	0	0
1990	4	0	0	0	0	0
1990	5	0	0	0	0	0
1990	6	0	0	0	0	0
1990	7	0	0	0	0	0
1990	8	0	0	0	0	0
1990	9	0	0	0	0	0
1990	10	0	0	0	0	0
1990	11	0	0	0	0	0
1990	12	0	0	0	0	0
1991	1	0	0	0	0	0
1991	2	0	0	0	0	0
1991	3	0	0	0	0	0
1991	4	0	0	0	0	0
1991	5	0	0	0	0	0
1991	6	0	0	0	0	0
1991	7	0	0	0	0	0
1991	8	0	0	0	0	0
1991	9	0	0	0	0	0
1991	10	0	0	0	0	0
1991	11	0	0	0	0	0
1991	12	0	0	0	0	0
1992	1	0	0	0	0	0
1992	2	0	0	0	0	0
1992	3	0	0	0	0	0
1992	4	0	0	0	0	0
1992	5	0	0	0	0	0
1992	6	0	0	0	0	0
1992	7	0	0	0	0	0

SHORT TERM MODELS 30
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D962	D963	D967971	D97B	D971ON
1992	8	0.00000	0	0	0	0
1992	9	0.00000	0	0	0	0
1992	10	0.00000	0	0	0	0
1992	11	0.00000	0	0	0	0
1992	12	0.00000	0	0	0	0
1993	1	0.00000	0	0	0	0
1993	2	0.00000	0	0	0	0
1993	3	0.00000	0	0	0	0
1993	4	0.00000	0	0	0	0
1993	5	0.00000	0	0	0	0
1993	6	0.00000	0	0	0	0
1993	7	0.00000	0	0	0	0
1993	8	0.00000	0	0	0	0
1993	9	0.00000	0	0	0	0
1993	10	0.00000	0	0	0	0
1993	11	0.00000	0	0	0	0
1993	12	0.00000	0	0	0	0
1994	1	0.00000	0	0	0	0
1994	2	0.00000	0	0	0	0
1994	3	0.00000	0	0	0	0
1994	4	0.00000	0	0	0	0
1994	5	0.00000	0	0	0	0
1994	6	0.00000	0	0	0	0
1994	7	0.00000	0	0	0	0
1994	8	0.00000	0	0	0	0
1994	9	0.00000	0	0	0	0
1994	10	0.00000	0	0	0	0
1994	11	0.00000	0	0	0	0
1994	12	0.00000	0	0	0	0
1995	1	0.00000	0	0	0	0
1995	2	0.00000	0	0	0	0
1995	3	0.00000	0	0	0	0
1995	4	0.00000	0	0	0	0
1995	5	0.00000	0	0	0	0
1995	6	0.00000	0	0	0	0
1995	7	0.00000	0	0	0	0
1995	8	0.00000	0	0	0	0
1995	9	0.00000	0	0	0	0
1995	10	0.00000	0	0	0	0
1995	11	0.00000	0	0	0	0
1995	12	0.00000	0	0	0	0
1996	1	0.00000	0	0	0	0
1996	2	1.03571	0	0	0	0
1996	3	0.00000	1	0	0	0
1996	4	0.00000	0	0	0	0
1996	5	0.00000	0	0	0	0
1996	6	0.00000	0	0	0	0
1996	7	0.00000	0	1	0	0
1996	8	0.00000	0	1	0	0
1996	9	0.00000	0	1	0	0
1996	10	0.00000	0	1	0	0
1996	11	0.00000	0	1	0	0
1996	12	0.00000	0	1	0	0
1997	1	0.00000	0	1	0	1
1997	2	0.00000	0	0	0	1

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D962	D963	D967971	D978	D9710N
1997	3	0	0	0	0	1.00000
1997	4	0	0	0	0	1.00000
1997	5	0	0	0	0	1.00000
1997	6	0	0	0	0	1.00000
1997	7	0	0	0	0	1.00000
1997	8	0	0	0	0	1.00000
1997	9	0	0	0	0	1.00000
1997	10	0	0	0	0	1.00000
1997	11	0	0	0	1	1.00000
1997	12	0	0	0	0	1.00000
1998	1	0	0	0	0	1.00000
1998	2	0	0	0	0	1.00000
1998	3	0	0	0	0	1.00000
1998	4	0	0	0	0	1.00000
1998	5	0	0	0	0	1.00000
1998	6	0	0	0	0	1.00000
1998	7	0	0	0	0	1.00000
1998	8	0	0	0	0	1.00000
1998	9	0	0	0	0	1.00000
1998	10	0	0	0	0	1.00000
1998	11	0	0	0	0	1.00000
1998	12	0	0	0	0	1.00000
1999	1	0	0	0	0	1.00000
1999	2	0	0	0	0	1.00000
1999	3	0	0	0	0	1.00000
1999	4	0	0	0	0	1.00000
1999	5	0	0	0	0	1.00000
1999	6	0	0	0	0	1.00000
1999	7	0	0	0	0	1.00000
1999	8	0	0	0	0	1.00000
1999	9	0	0	0	0	1.00000
1999	10	0	0	0	0	1.00000
1999	11	0	0	0	0	1.00000
1999	12	0	0	0	0	1.00000
2000	1	0	0	0	0	1.00000
2000	2	0	0	0	0	1.03571
2000	3	0	0	0	0	1.00000
2000	4	0	0	0	0	1.00000
2000	5	0	0	0	0	1.00000
2000	6	0	0	0	0	1.00000
2000	7	0	0	0	0	1.00000
2000	8	0	0	0	0	1.00000
2000	9	0	0	0	0	1.00000
2000	10	0	0	0	0	1.00000
2000	11	0	0	0	0	1.00000
2000	12	0	0	0	0	1.00000
2001	1	0	0	0	0	1.00000
2001	2	0	0	0	0	1.00000
2001	3	0	0	0	0	1.00000
2001	4	0	0	0	0	1.00000
2001	5	0	0	0	0	1.00000
2001	6	0	0	0	0	1.00000
2001	7	0	0	0	0	1.00000
2001	8	0	0	0	0	1.00000
2001	9	0	0	0	0	1.00000

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D962	D963	D967971	D978	D9710N
2001	10	0	0	0	0	1.00000
2001	11	0	0	0	0	1.00000
2001	12	0	0	0	0	1.00000
2002	1	0	0	0	0	1.00000
2002	2	0	0	0	0	1.00000
2002	3	0	0	0	0	1.00000
2002	4	0	0	0	0	1.00000
2002	5	0	0	0	0	1.00000
2002	6	0	0	0	0	1.00000
2002	7	0	0	0	0	1.00000
2002	8	0	0	0	0	1.00000
2002	9	0	0	0	0	1.00000
2002	10	0	0	0	0	1.00000
2002	11	0	0	0	0	1.00000
2002	12	0	0	0	0	1.00000
2003	1	0	0	0	0	1.00000
2003	2	0	0	0	0	1.00000
2003	3	0	0	0	0	1.00000
2003	4	0	0	0	0	1.00000
2003	5	0	0	0	0	1.00000
2003	6	0	0	0	0	1.00000
2003	7	0	0	0	0	1.00000
2003	8	0	0	0	0	1.00000
2003	9	0	0	0	0	1.00000
2003	10	0	0	0	0	1.00000
2003	11	0	0	0	0	1.00000
2003	12	0	0	0	0	1.00000
2004	1	0	0	0	0	1.00000
2004	2	0	0	0	0	1.03571
2004	3	0	0	0	0	1.00000
2004	4	0	0	0	0	1.00000
2004	5	0	0	0	0	1.00000
2004	6	0	0	0	0	1.00000
2004	7	0	0	0	0	1.00000
2004	8	0	0	0	0	1.00000
2004	9	0	0	0	0	1.00000
2004	10	0	0	0	0	1.00000
2004	11	0	0	0	0	1.00000
2004	12	0	0	0	0	1.00000

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

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YEAR	MONTH	D977	D97797A	D978	D981	D983
1988	1	0	0	0	0	0
1988	2	0	0	0	0	0
1988	3	0	0	0	0	0
1988	4	0	0	0	0	0
1988	5	0	0	0	0	0
1988	6	0	0	0	0	0
1988	7	0	0	0	0	0
1988	8	0	0	0	0	0
1988	9	0	0	0	0	0
1988	10	0	0	0	0	0
1988	11	0	0	0	0	0
1988	12	0	0	0	0	0
1989	1	0	0	0	0	0
1989	2	0	0	0	0	0
1989	3	0	0	0	0	0
1989	4	0	0	0	0	0
1989	5	0	0	0	0	0
1989	6	0	0	0	0	0
1989	7	0	0	0	0	0
1989	8	0	0	0	0	0
1989	9	0	0	0	0	0
1989	10	0	0	0	0	0
1989	11	0	0	0	0	0
1989	12	0	0	0	0	0
1990	1	0	0	0	0	0
1990	2	0	0	0	0	0
1990	3	0	0	0	0	0
1990	4	0	0	0	0	0
1990	5	0	0	0	0	0
1990	6	0	0	0	0	0
1990	7	0	0	0	0	0
1990	8	0	0	0	0	0
1990	9	0	0	0	0	0
1990	10	0	0	0	0	0
1990	11	0	0	0	0	0
1990	12	0	0	0	0	0
1991	1	0	0	0	0	0
1991	2	0	0	0	0	0
1991	3	0	0	0	0	0
1991	4	0	0	0	0	0
1991	5	0	0	0	0	0
1991	6	0	0	0	0	0
1991	7	0	0	0	0	0
1991	8	0	0	0	0	0
1991	9	0	0	0	0	0
1991	10	0	0	0	0	0
1991	11	0	0	0	0	0
1991	12	0	0	0	0	0
1992	1	0	0	0	0	0
1992	2	0	0	0	0	0
1992	3	0	0	0	0	0
1992	4	0	0	0	0	0
1992	5	0	0	0	0	0
1992	6	0	0	0	0	0
1992	7	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

34

YEAR	MONTH	D977	D97797A	D978	D981	D983
1992	8	0	0	0	0	0
1992	9	0	0	0	0	0
1992	10	0	0	0	0	0
1992	11	0	0	0	0	0
1992	12	0	0	0	0	0
1993	1	0	0	0	0	0
1993	2	0	0	0	0	0
1993	3	0	0	0	0	0
1993	4	0	0	0	0	0
1993	5	0	0	0	0	0
1993	6	0	0	0	0	0
1993	7	0	0	0	0	0
1993	8	0	0	0	0	0
1993	9	0	0	0	0	0
1993	10	0	0	0	0	0
1993	11	0	0	0	0	0
1993	12	0	0	0	0	0
1994	1	0	0	0	0	0
1994	2	0	0	0	0	0
1994	3	0	0	0	0	0
1994	4	0	0	0	0	0
1994	5	0	0	0	0	0
1994	6	0	0	0	0	0
1994	7	0	0	0	0	0
1994	8	0	0	0	0	0
1994	9	0	0	0	0	0
1994	10	0	0	0	0	0
1994	11	0	0	0	0	0
1994	12	0	0	0	0	0
1995	1	0	0	0	0	0
1995	2	0	0	0	0	0
1995	3	0	0	0	0	0
1995	4	0	0	0	0	0
1995	5	0	0	0	0	0
1995	6	0	0	0	0	0
1995	7	0	0	0	0	0
1995	8	0	0	0	0	0
1995	9	0	0	0	0	0
1995	10	0	0	0	0	0
1995	11	0	0	0	0	0
1995	12	0	0	0	0	0
1996	1	0	0	0	0	0
1996	2	0	0	0	0	0
1996	3	0	0	0	0	0
1996	4	0	0	0	0	0
1996	5	0	0	0	0	0
1996	6	0	0	0	0	0
1996	7	0	0	0	0	0
1996	8	0	0	0	0	0
1996	9	0	0	0	0	0
1996	10	0	0	0	0	0
1996	11	0	0	0	0	0
1996	12	0	0	0	0	0
1997	1	0	0	0	0	0
1997	2	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D977	D97797A	D978	D981	D983
1997	3	0	0	0	0	0
1997	4	0	0	0	0	0
1997	5	0	0	0	0	0
1997	6	0	0	0	0	0
1997	7	1	1	0	0	0
1997	8	0	1	1	0	0
1997	9	0	1	0	0	0
1997	10	0	1	0	0	0
1997	11	0	0	0	0	0
1997	12	0	0	0	0	0
1998	1	0	0	0	1	0
1998	2	0	0	0	0	0
1998	3	0	0	0	0	1
1998	4	0	0	0	0	0
1998	5	0	0	0	0	0
1998	6	0	0	0	0	0
1998	7	0	0	0	0	0
1998	8	0	0	0	0	0
1998	9	0	0	0	0	0
1998	10	0	0	0	0	0
1998	11	0	0	0	0	0
1998	12	0	0	0	0	0
1999	1	0	0	0	0	0
1999	2	0	0	0	0	0
1999	3	0	0	0	0	0
1999	4	0	0	0	0	0
1999	5	0	0	0	0	0
1999	6	0	0	0	0	0
1999	7	0	0	0	0	0
1999	8	0	0	0	0	0
1999	9	0	0	0	0	0
1999	10	0	0	0	0	0
1999	11	0	0	0	0	0
1999	12	0	0	0	0	0
2000	1	0	0	0	0	0
2000	2	0	0	0	0	0
2000	3	0	0	0	0	0
2000	4	0	0	0	0	0
2000	5	0	0	0	0	0
2000	6	0	0	0	0	0
2000	7	0	0	0	0	0
2000	8	0	0	0	0	0
2000	9	0	0	0	0	0
2000	10	0	0	0	0	0
2000	11	0	0	0	0	0
2000	12	0	0	0	0	0
2001	1	0	0	0	0	0
2001	2	0	0	0	0	0
2001	3	0	0	0	0	0
2001	4	0	0	0	0	0
2001	5	0	0	0	0	0
2001	6	0	0	0	0	0
2001	7	0	0	0	0	0
2001	8	0	0	0	0	0
2001	9	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D977	D97797A	D978	D981	D983
2001	10	0	0	0	0	0
2001	11	0	0	0	0	0
2001	12	0	0	0	0	0
2002	1	0	0	0	0	0
2002	2	0	0	0	0	0
2002	3	0	0	0	0	0
2002	4	0	0	0	0	0
2002	5	0	0	0	0	0
2002	6	0	0	0	0	0
2002	7	0	0	0	0	0
2002	8	0	0	0	0	0
2002	9	0	0	0	0	0
2002	10	0	0	0	0	0
2002	11	0	0	0	0	0
2002	12	0	0	0	0	0
2003	1	0	0	0	0	0
2003	2	0	0	0	0	0
2003	3	0	0	0	0	0
2003	4	0	0	0	0	0
2003	5	0	0	0	0	0
2003	6	0	0	0	0	0
2003	7	0	0	0	0	0
2003	8	0	0	0	0	0
2003	9	0	0	0	0	0
2003	10	0	0	0	0	0
2003	11	0	0	0	0	0
2003	12	0	0	0	0	0
2004	1	0	0	0	0	0
2004	2	0	0	0	0	0
2004	3	0	0	0	0	0
2004	4	0	0	0	0	0
2004	5	0	0	0	0	0
2004	6	0	0	0	0	0
2004	7	0	0	0	0	0
2004	8	0	0	0	0	0
2004	9	0	0	0	0	0
2004	10	0	0	0	0	0
2004	11	0	0	0	0	0
2004	12	0	0	0	0	0

SHORT TERM MODELS 37
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D983987	D987
1988	1	0	0
1988	2	0	0
1988	3	0	0
1988	4	0	0
1988	5	0	0
1988	6	0	0
1988	7	0	0
1988	8	0	0
1988	9	0	0
1988	10	0	0
1988	11	0	0
1988	12	0	0
1989	1	0	0
1989	2	0	0
1989	3	0	0
1989	4	0	0
1989	5	0	0
1989	6	0	0
1989	7	0	0
1989	8	0	0
1989	9	0	0
1989	10	0	0
1989	11	0	0
1989	12	0	0
1990	1	0	0
1990	2	0	0
1990	3	0	0
1990	4	0	0
1990	5	0	0
1990	6	0	0
1990	7	0	0
1990	8	0	0
1990	9	0	0
1990	10	0	0
1990	11	0	0
1990	12	0	0
1991	1	0	0
1991	2	0	0
1991	3	0	0
1991	4	0	0
1991	5	0	0
1991	6	0	0
1991	7	0	0
1991	8	0	0
1991	9	0	0
1991	10	0	0
1991	11	0	0
1991	12	0	0
1992	1	0	0
1992	2	0	0
1992	3	0	0
1992	4	0	0
1992	5	0	0
1992	6	0	0
1992	7	0	0

SHORT TERM MODELS 38
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D983987	D987
1992	8	0	0
1992	9	0	0
1992	10	0	0
1992	11	0	0
1992	12	0	0
1993	1	0	0
1993	2	0	0
1993	3	0	0
1993	4	0	0
1993	5	0	0
1993	6	0	0
1993	7	0	0
1993	8	0	0
1993	9	0	0
1993	10	0	0
1993	11	0	0
1993	12	0	0
1994	1	0	0
1994	2	0	0
1994	3	0	0
1994	4	0	0
1994	5	0	0
1994	6	0	0
1994	7	0	0
1994	8	0	0
1994	9	0	0
1994	10	0	0
1994	11	0	0
1994	12	0	0
1995	1	0	0
1995	2	0	0
1995	3	0	0
1995	4	0	0
1995	5	0	0
1995	6	0	0
1995	7	0	0
1995	8	0	0
1995	9	0	0
1995	10	0	0
1995	11	0	0
1995	12	0	0
1996	1	0	0
1996	2	0	0
1996	3	0	0
1996	4	0	0
1996	5	0	0
1996	6	0	0
1996	7	0	0
1996	8	0	0
1996	9	0	0
1996	10	0	0
1996	11	0	0
1996	12	0	0
1997	1	0	0
1997	2	0	0

SHORT TERM MODELS

BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D983987	D987
1997	3	0	0
1997	4	0	0
1997	5	0	0
1997	6	0	0
1997	7	0	0
1997	8	0	0
1997	9	0	0
1997	10	0	0
1997	11	0	0
1997	12	0	0
1998	1	0	0
1998	2	0	0
1998	3	1	0
1998	4	1	0
1998	5	1	0
1998	6	1	0
1998	7	1	1
1998	8	0	0
1998	9	0	0
1998	10	0	0
1998	11	0	0
1998	12	0	0
1999	1	0	0
1999	2	0	0
1999	3	0	0
1999	4	0	0
1999	5	0	0
1999	6	0	0
1999	7	0	0
1999	8	0	0
1999	9	0	0
1999	10	0	0
1999	11	0	0
1999	12	0	0
2000	1	0	0
2000	2	0	0
2000	3	0	0
2000	4	0	0
2000	5	0	0
2000	6	0	0
2000	7	0	0
2000	8	0	0
2000	9	0	0
2000	10	0	0
2000	11	0	0
2000	12	0	0
2001	1	0	0
2001	2	0	0
2001	3	0	0
2001	4	0	0
2001	5	0	0
2001	6	0	0
2001	7	0	0
2001	8	0	0
2001	9	0	0

SHORT TERM MODELS

BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D983987	D987
2001	10	0	0
2001	11	0	0
2001	12	0	0
2002	1	0	0
2002	2	0	0
2002	3	0	0
2002	4	0	0
2002	5	0	0
2002	6	0	0
2002	7	0	0
2002	8	0	0
2002	9	0	0
2002	10	0	0
2002	11	0	0
2002	12	0	0
2003	1	0	0
2003	2	0	0
2003	3	0	0
2003	4	0	0
2003	5	0	0
2003	6	0	0
2003	7	0	0
2003	8	0	0
2003	9	0	0
2003	10	0	0
2003	11	0	0
2003	12	0	0
2004	1	0	0
2004	2	0	0
2004	3	0	0
2004	4	0	0
2004	5	0	0
2004	6	0	0
2004	7	0	0
2004	8	0	0
2004	9	0	0
2004	10	0	0
2004	11	0	0
2004	12	0	0

SHORT TERM MODELS
TREND VARIABLES

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YEAR	MONTH	T	T9410N
1988	1	1988.00	0
1988	2	1988.08	0
1988	3	1988.17	0
1988	4	1988.25	0
1988	5	1988.33	0
1988	6	1988.42	0
1988	7	1988.50	0
1988	8	1988.58	0
1988	9	1988.67	0
1988	10	1988.75	0
1988	11	1988.83	0
1988	12	1988.92	0
1989	1	1989.00	0
1989	2	1989.08	0
1989	3	1989.17	0
1989	4	1989.25	0
1989	5	1989.33	0
1989	6	1989.42	0
1989	7	1989.50	0
1989	8	1989.58	0
1989	9	1989.67	0
1989	10	1989.75	0
1989	11	1989.83	0
1989	12	1989.92	0
1990	1	1990.00	0
1990	2	1990.08	0
1990	3	1990.17	0
1990	4	1990.25	0
1990	5	1990.33	0
1990	6	1990.42	0
1990	7	1990.50	0
1990	8	1990.58	0
1990	9	1990.67	0
1990	10	1990.75	0
1990	11	1990.83	0
1990	12	1990.92	0
1991	1	1991.00	0
1991	2	1991.08	0
1991	3	1991.17	0
1991	4	1991.25	0
1991	5	1991.33	0
1991	6	1991.42	0
1991	7	1991.50	0
1991	8	1991.58	0
1991	9	1991.67	0
1991	10	1991.75	0
1991	11	1991.83	0
1991	12	1991.92	0
1992	1	1992.00	0
1992	2	1992.08	0
1992	3	1992.17	0
1992	4	1992.25	0
1992	5	1992.33	0
1992	6	1992.42	0
1992	7	1992.50	0

SHORT TERM MODELS
TREND VARIABLES

42

YEAR	MONTH	T	T9410N
1992	8	1992.58	0.00
1992	9	1992.67	0.00
1992	10	1992.75	0.00
1992	11	1992.83	0.00
1992	12	1992.92	0.00
1993	1	1993.00	0.00
1993	2	1993.08	0.00
1993	3	1993.17	0.00
1993	4	1993.25	0.00
1993	5	1993.33	0.00
1993	6	1993.42	0.00
1993	7	1993.50	0.00
1993	8	1993.58	0.00
1993	9	1993.67	0.00
1993	10	1993.75	0.00
1993	11	1993.83	0.00
1993	12	1993.92	0.00
1994	1	1994.00	1994.00
1994	2	1994.08	1994.08
1994	3	1994.17	1994.17
1994	4	1994.25	1994.25
1994	5	1994.33	1994.33
1994	6	1994.42	1994.42
1994	7	1994.50	1994.50
1994	8	1994.58	1994.58
1994	9	1994.67	1994.67
1994	10	1994.75	1994.75
1994	11	1994.83	1994.83
1994	12	1994.92	1994.92
1995	1	1995.00	1995.00
1995	2	1995.08	1995.08
1995	3	1995.17	1995.17
1995	4	1995.25	1995.25
1995	5	1995.33	1995.33
1995	6	1995.42	1995.42
1995	7	1995.50	1995.50
1995	8	1995.58	1995.58
1995	9	1995.67	1995.67
1995	10	1995.75	1995.75
1995	11	1995.83	1995.83
1995	12	1995.92	1995.92
1996	1	1996.00	1996.00
1996	2	1996.08	1996.08
1996	3	1996.17	1996.17
1996	4	1996.25	1996.25
1996	5	1996.33	1996.33
1996	6	1996.42	1996.42
1996	7	1996.50	1996.50
1996	8	1996.58	1996.58
1996	9	1996.67	1996.67
1996	10	1996.75	1996.75
1996	11	1996.83	1996.83
1996	12	1996.92	1996.92
1997	1	1997.00	1997.00
1997	2	1997.08	1997.08

SHORT TERM MODELS 43
TREND VARIABLES

YEAR	MONTH	T	T9410N
1997	3	1997.17	1997.17
1997	4	1997.25	1997.25
1997	5	1997.33	1997.33
1997	6	1997.42	1997.42
1997	7	1997.50	1997.50
1997	8	1997.58	1997.58
1997	9	1997.67	1997.67
1997	10	1997.75	1997.75
1997	11	1997.83	1997.83
1997	12	1997.92	1997.92
1998	1	1998.00	1998.00
1998	2	1998.08	1998.08
1998	3	1998.17	1998.17
1998	4	1998.25	1998.25
1998	5	1998.33	1998.33
1998	6	1998.42	1998.42
1998	7	1998.50	1998.50
1998	8	1998.58	1998.58
1998	9	1998.67	1998.67
1998	10	1998.75	1998.75
1998	11	1998.83	1998.83
1998	12	1998.92	1998.92
1999	1	1999.00	1999.00
1999	2	1999.08	1999.08
1999	3	1999.17	1999.17
1999	4	1999.25	1999.25
1999	5	1999.33	1999.33
1999	6	1999.42	1999.42
1999	7	1999.50	1999.50
1999	8	1999.58	1999.58
1999	9	1999.67	1999.67
1999	10	1999.75	1999.75
1999	11	1999.83	1999.83
1999	12	1999.92	1999.92
2000	1	2000.00	2000.00
2000	2	2000.08	2000.08
2000	3	2000.17	2000.17
2000	4	2000.25	2000.25
2000	5	2000.33	2000.33
2000	6	2000.42	2000.42
2000	7	2000.50	2000.50
2000	8	2000.58	2000.58
2000	9	2000.67	2000.67
2000	10	2000.75	2000.75
2000	11	2000.83	2000.83
2000	12	2000.92	2000.92
2001	1	2001.00	2001.00
2001	2	2001.08	2001.08
2001	3	2001.17	2001.17
2001	4	2001.25	2001.25
2001	5	2001.33	2001.33
2001	6	2001.42	2001.42
2001	7	2001.50	2001.50
2001	8	2001.58	2001.58
2001	9	2001.67	2001.67

SHORT TERM MODELS 44
TREND VARIABLES

YEAR	MONTH	T	T9410N
2001	10	2001.75	2001.75
2001	11	2001.83	2001.83
2001	12	2001.92	2001.92
2002	1	2002.00	2002.00
2002	2	2002.08	2002.08
2002	3	2002.17	2002.17
2002	4	2002.25	2002.25
2002	5	2002.33	2002.33
2002	6	2002.42	2002.42
2002	7	2002.50	2002.50
2002	8	2002.58	2002.58
2002	9	2002.67	2002.67
2002	10	2002.75	2002.75
2002	11	2002.83	2002.83
2002	12	2002.92	2002.92
2003	1	2003.00	2003.00
2003	2	2003.08	2003.08
2003	3	2003.17	2003.17
2003	4	2003.25	2003.25
2003	5	2003.33	2003.33
2003	6	2003.42	2003.42
2003	7	2003.50	2003.50
2003	8	2003.58	2003.58
2003	9	2003.67	2003.67
2003	10	2003.75	2003.75
2003	11	2003.83	2003.83
2003	12	2003.92	2003.92
2004	1	2004.00	2004.00
2004	2	2004.08	2004.08
2004	3	2004.17	2004.17
2004	4	2004.25	2004.25
2004	5	2004.33	2004.33
2004	6	2004.42	2004.42
2004	7	2004.50	2004.50
2004	8	2004.58	2004.58
2004	9	2004.67	2004.67
2004	10	2004.75	2004.75
2004	11	2004.83	2004.83
2004	12	2004.92	2004.92

SHORT TERM MODELS
OTHER VARIABLES
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YEAR	MONTH	CDD_KPC	CDD2_KPC	FRB331	HDD_KPC	HDD2_KPC
1988	1	0	0	107.546	1043	1087849
1988	2	0	0	108.129	858	736164
1988	3	7	49	107.426	584	341056
1988	4	10	100	106.723	325	105625
1988	5	68	4624	106.020	104	10816
1988	6	230	52900	107.057	30	900
1988	7	409	167281	108.093	0	0
1988	8	379	143641	109.130	0	0
1988	9	102	10404	108.277	38	1444
1988	10	10	100	107.425	485	235225
1988	11	2	4	106.572	538	289444
1988	12	0	0	108.504	849	720801
1989	1	0	0	110.435	745	555025
1989	2	0	0	112.367	845	714025
1989	3	12	144	111.098	548	300304
1989	4	19	361	109.829	340	115600
1989	5	61	3721	108.568	213	45369
1989	6	201	40401	106.812	4	16
1989	7	331	109561	105.064	0	0
1989	8	285	81225	103.316	7	49
1989	9	147	21609	102.421	70	4900
1989	10	24	576	101.526	283	80089
1989	11	0	0	100.631	557	310249
1989	12	0	0	102.043	1217	1481089
1990	1	0	0	103.454	702	492804
1990	2	0	0	104.866	585	342225
1990	3	35	1225	105.788	457	208849
1990	4	33	1089	106.694	331	109561
1990	5	47	2209	107.608	107	11449
1990	6	231	53361	108.198	7	49
1990	7	340	115600	108.787	0	0
1990	8	281	78961	109.376	2	4
1990	9	165	27225	108.237	65	4225
1990	10	25	625	107.099	261	68121
1990	11	8	64	105.960	440	193600
1990	12	0	0	101.341	670	448900
1991	1	0	0	96.722	894	799236
1991	2	0	0	92.102	682	465124
1991	3	15	225	92.276	533	284089
1991	4	45	2025	92.450	188	35344
1991	5	245	60025	92.624	25	625
1991	6	308	94864	94.526	0	0
1991	7	438	191844	96.429	0	0
1991	8	355	126025	98.332	0	0
1991	9	206	42436	98.639	75	5625
1991	10	54	2916	98.945	225	50625
1991	11	4	16	99.252	597	356409
1991	12	0	0	99.403	756	571536
1992	1	0	0	99.553	904	817216
1992	2	0	0	99.704	678	459684
1992	3	1	1	99.843	595	354025
1992	4	41	1681	99.983	311	96721
1992	5	66	4356	100.122	160	25600
1992	6	149	22201	99.895	17	289
1992	7	334	111556	99.669	0	0

SHORT TERM MODELS
OTHER VARIABLES
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YEAR	MONTH	CDD_KPC	CDD2_KPC	FRB331	HDD_KPC	HDD2_KPC
1992	8	210	44100	99.442	1	1
1992	9	136	18496	99.689	59	3481
1992	10	5	25	99.936	312	97344
1992	11	0	0	100.184	527	277729
1992	12	0	0	101.980	837	700569
1993	1	0	0	103.776	789	622521
1993	2	0	0	105.572	871	758641
1993	3	0	0	105.652	714	509796
1993	4	6	36	105.731	323	104329
1993	5	82	6724	105.810	71	5041
1993	6	249	62001	106.459	24	576
1993	7	453	205209	107.109	0	0
1993	8	371	137641	107.758	0	0
1993	9	116	13456	108.533	55	3025
1993	10	10	100	109.308	307	94249
1993	11	7	49	110.083	548	300304
1993	12	0	0	109.409	885	783225
1994	1	0	0	108.734	1167	1361889
1994	2	0	0	108.059	762	580644
1994	3	1	1	111.107	620	384400
1994	4	50	2500	114.154	199	39601
1994	5	43	1849	117.202	181	32761
1994	6	316	99856	114.844	1	1
1994	7	374	139876	112.487	0	0
1994	8	245	60025	110.129	2	4
1994	9	59	3481	113.084	35	1225
1994	10	7	49	116.038	271	73441
1994	11	5	25	118.992	402	161604
1994	12	0	0	119.570	722	521284
1995	1	0	0	120.147	934	872356
1995	2	0	0	120.724	858	736164
1995	3	0	0	119.430	525	275625
1995	4	22	484	118.136	280	78400
1995	5	58	3364	116.842	132	17424
1995	6	228	51984	116.622	2	4
1995	7	388	150544	116.403	0	0
1995	8	444	197136	116.184	0	0
1995	9	106	11236	116.613	60	3600
1995	10	16	256	117.043	255	65025
1995	11	2	4	117.472	706	498436
1995	12	0	0	116.785	981	962361
1996	1	0	0	116.098	1015	1030225
1996	2	0	0	115.412	827	683929
1996	3	0	0	115.890	765	585225
1996	4	39	1521	116.368	349	121801
1996	5	127	16129	116.846	92	8464
1996	6	258	66564	117.186	2	4
1996	7	275	75625	117.526	0	0
1996	8	278	77284	117.865	0	0
1996	9	101	10201	118.609	64	4096
1996	10	5	25	119.353	263	69169
1996	11	4	16	120.097	749	561001
1996	12	0	0	119.650	752	565504
1997	1	1	1	119.203	971	942841
1997	2	3	9	118.756	636	404496

SHORT TERM MODELS
OTHER VARIABLES

YEAR	MONTH	CDD_KPC	CDD2_KPC	FRB331	HDD_KPC	HDD2_KPC
1997	3	0	0	120.242	549	301401
1997	4	9	81	121.728	421	177241
1997	5	23	529	123.214	212	44944
1997	6	175	30625	122.859	31	961
1997	7	320	102400	122.504	0	0
1997	8	210	44100	122.150	5	25
1997	9	63	3969	123.746	49	2401
1997	10	35	1225	125.343	308	94864
1997	11	0	0	126.939	660	435600
1997	12	0	0	127.218	865	748225
1998	1	0	0	127.496	724	524176
1998	2	0	0	127.774	633	400689
1998	3	44	1936	126.330	595	354025
1998	4	2	4	124.886	297	88209
1998	5	107	11449	123.441	54	2916
1998	6	230	52900	123.973	33	1089
1998	7	297	88209	124.504	0	0
1998	8	306	93636	125.035	0	0
1998	9	253	64009	124.861	19	361
1998	10	27	729	124.686	250	62500
1998	11	0	0	124.511	518	268324
1998	12	4	16	124.604	751	564001
1999	1	0	0	124.697	846	715716
1999	2	0	0	124.790	701	491401
1999	3	0	0	124.914	749	561001
1999	4	20	400	125.038	217	47089
1999	5	70	4900	125.161	47	2209
1999	6	288	82944	125.401	4	16
1999	7	483	233289	125.641	0	0
1999	8	286	81796	125.880	0	0
1999	9	92	8464	126.179	48	2304
1999	10	21	441	126.478	285	81225
1999	11	3	9	126.776	548	300304
1999	12	1	1	127.146	847	717409
2000	1	0	0	127.517	988	976144
2000	2	0	0	127.887	802	643204
2000	3	7	49	128.297	596	355216
2000	4	25	625	128.707	303	91809
2000	5	87	7569	129.117	116	13456
2000	6	228	51984	129.476	12	144
2000	7	353	124609	129.836	0	0
2000	8	312	97344	130.196	2	4
2000	9	140	19600	130.568	54	2916
2000	10	21	441	130.941	285	81225
2000	11	3	9	131.313	548	300304
2000	12	1	1	131.646	847	717409
2001	1	0	0	131.980	988	976144
2001	2	0	0	132.313	802	643204
2001	3	7	49	132.608	596	355216
2001	4	25	625	132.903	303	91809
2001	5	87	7569	133.198	116	13456
2001	6	228	51984	133.499	12	144
2001	7	353	124609	133.801	0	0
2001	8	312	97344	134.102	2	4
2001	9	140	19600	134.397	54	2916

SHORT TERM MODELS
OTHER VARIABLES

YEAR	MONTH	CDD_KPC	CDD2_KPC	FRB331	HDD_KPC	HDD2_KPC
2001	10	21	441	134.691	285	81225
2001	11	3	9	134.985	548	300304
2001	12	1	1	135.324	847	717409
2002	1	0	0	135.662	988	976144
2002	2	0	0	136.000	802	643204
2002	3	7	49	136.339	596	355216
2002	4	25	625	136.678	303	91809
2002	5	87	7569	137.017	116	13456
2002	6	228	51984	137.305	12	144
2002	7	353	124609	137.594	0	0
2002	8	312	97344	137.883	2	4
2002	9	140	19600	138.223	54	2916
2002	10	21	441	138.564	285	81225
2002	11	3	9	138.905	548	300304
2002	12	1	1	139.231	847	717409
2003	1	0	0	139.558	988	976144
2003	2	0	0	139.885	802	643204
2003	3	7	49	140.257	596	355216
2003	4	25	625	140.630	303	91809
2003	5	87	7569	141.002	116	13456
2003	6	228	51984	141.368	12	144
2003	7	353	124609	141.734	0	0
2003	8	312	97344	142.100	2	4
2003	9	140	19600	142.466	54	2916
2003	10	21	441	142.833	285	81225
2003	11	3	9	143.200	548	300304
2003	12	1	1	143.567	847	717409
2004	1	0	0	143.933	988	976144
2004	2	0	0	144.300	802	643204
2004	3	7	49	144.667	596	355216
2004	4	25	625	145.033	303	91809
2004	5	87	7569	145.400	116	13456
2004	6	228	51984	145.767	12	144
2004	7	353	124609	146.133	0	0
2004	8	312	97344	146.500	2	4
2004	9	140	19600	146.867	54	2916
2004	10	21	441	147.233	285	81225
2004	11	3	9	147.600	548	300304
2004	12	1	1	147.967	847	717409

OTHER VARIABLES -- CONTINUED

YEAR	MONTH	HDD3_KPC
1988	1	1134626507
1988	2	631628712
1988	3	199176704
1988	4	34328125
1988	5	1124864
1988	6	27000
1988	7	0
1988	8	0
1988	9	54872
1988	10	114084125
1988	11	155720872
1988	12	611960049
1989	1	413493625
1989	2	603351125
1989	3	164566592
1989	4	39304008
1989	5	9663597
1989	6	64
1989	7	0
1989	8	343
1989	9	343000
1989	10	22665187
1989	11	172808695
1989	12	1802485313
1990	1	345948408
1990	2	200201625
1990	3	95443993
1990	4	36264691
1990	5	1225043
1990	6	343
1990	7	0
1990	8	8
1990	9	274625
1990	10	17779581
1990	11	85184000
1990	12	300763000
1991	1	714516984
1991	2	317214568
1991	3	151419437
1991	4	6644672
1991	5	15625
1991	6	0
1991	7	0
1991	8	0
1991	9	421875
1991	10	11390625
1991	11	212776173
1991	12	432081216
1992	1	738763264
1992	2	311665752
1992	3	210644875
1992	4	30080231
1992	5	4096000
1992	6	4913
1992	7	0

OTHER VARIABLES -- CONTINUED

YEAR	MONTH	HDD3_KPC
1992	8	1
1992	9	205379
1992	10	30371328
1992	11	146363183
1992	12	586376253
1993	1	491169069
1993	2	660776311
1993	3	363994344
1993	4	33698267
1993	5	357911
1993	6	13824
1993	7	0
1993	8	0
1993	9	166375
1993	10	28934443
1993	11	164566592
1993	12	693154125
1994	1	1589324463
1994	2	442450728
1994	3	238328000
1994	4	7880599
1994	5	5929741
1994	6	1
1994	7	0
1994	8	8
1994	9	42875
1994	10	19902511
1994	11	64964808
1994	12	376367048
1995	1	814780504
1995	2	631628712
1995	3	144703125
1995	4	21952000
1995	5	2299968
1995	6	8
1995	7	0
1995	8	0
1995	9	216000
1995	10	16581375
1995	11	551895816
1995	12	944076141
1996	1	1045678375
1996	2	565609283
1996	3	447697125
1996	4	42508549
1996	5	778688
1996	6	8
1996	7	0
1996	8	0
1996	9	262144
1996	10	18191447
1996	11	420189749
1996	12	425259008
1997	1	915498611
1997	2	257259456

SHORT TERM MODELS
OTHER VARIABLES -- CONTINUED 51

YEAR	MONTH	HDD3_KPC
1997	3	165469149
1997	4	74618461
1997	5	9528128
1997	6	29791
1997	7	0
1997	8	125
1997	9	117649
1997	10	29218112
1997	11	287496000
1997	12	647214625
1998	1	379503424
1998	2	253636137
1998	3	210644875
1998	4	26198073
1998	5	157464
1998	6	35937
1998	7	0
1998	8	0
1998	9	6859
1998	10	15625000
1998	11	158991832
1998	12	423564751
1999	1	605495736
1999	2	344472101
1999	3	420189749
1999	4	10218313
1999	5	103823
1999	6	64
1999	7	0
1999	8	0
1999	9	110592
1999	10	23149125
1999	11	164566592
1999	12	607645423
2000	1	964430272
2000	2	515849608
2000	3	211708736
2000	4	27818127
2000	5	1560896
2000	6	1728
2000	7	0
2000	8	0
2000	9	157464
2000	10	23149125
2000	11	164566592
2000	12	607645423
2001	1	964430272
2001	2	515849608
2001	3	211708736
2001	4	27818127
2001	5	1560896
2001	6	1728
2001	7	0
2001	8	0
2001	9	157464

SHORT TERM MODELS
OTHER VARIABLES -- CONTINUED 52

YEAR	MONTH	HDD3_KPC
2001	10	23149125
2001	11	164566592
2001	12	607645423
2002	1	964430272
2002	2	515849608
2002	3	211708736
2002	4	27818127
2002	5	1560896
2002	6	1728
2002	7	0
2002	8	0
2002	9	157464
2002	10	23149125
2002	11	164566592
2002	12	607645423
2003	1	964430272
2003	2	515849608
2003	3	211708736
2003	4	27818127
2003	5	1560896
2003	6	1728
2003	7	0
2003	8	0
2003	9	157464
2003	10	23149125
2003	11	164566592
2003	12	607645423
2004	1	964430272
2004	2	515849608
2004	3	211708736
2004	4	27818127
2004	5	1560896
2004	6	1728
2004	7	0
2004	8	0
2004	9	157464
2004	10	23149125
2004	11	164566592
2004	12	607645423

Autoreg Procedure

Model: ER_KPC
Dependent Variable = ER_KPC RESIDENTIAL ENERGY

Ordinary Least Squares Estimates

SSE	14824.97	DFE	107
MSE	138.5511	Root MSE	11.77077
SBC	1073.402	AIC	1013.509
Reg Rsq	0.9356	Total Rsq	0.9356
Durbin-Watson	1.5790		

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
Intercept	1	-6576.132025	1553.2	-4.234	0.0001
HDD_KPC	1	-0.008336	0.0773	-0.108	0.9143
HDD2_KPC	1	0.000218	0.000123	1.779	0.0781
HDD3_KPC	1	-0.000000112	6.155E-8	-1.827	0.0705
CDD_KPC	1	0.138187	0.0809	1.707	0.0906
CDD2_KPC	1	0.000088096	0.000144	0.614	0.5408
D1	1	11.666272	5.2496	2.222	0.0284
D2	1	-14.902062	5.4167	-2.751	0.0070
D3	1	-14.033924	6.6309	-2.116	0.0366
D4	1	-25.149683	10.3581	-2.428	0.0168
D5	1	-34.261062	13.9168	-2.462	0.0154
D6	1	-44.423726	17.9623	-2.473	0.0150
D7	1	-26.877631	19.2786	-1.394	0.1662
D8	1	-25.883220	18.7787	-1.378	0.1710
D9	1	-34.783502	15.9323	-2.183	0.0312
DA	1	-32.024374	10.5348	-3.040	0.0030
DB	1	-14.409783	6.7560	-2.133	0.0352
T	1	3.366791	0.7790	4.322	0.0001
D92292A	1	7.931699	4.5782	1.733	0.0861
D941ON	1	10.939772	5.3118	2.060	0.0419
D94294C	1	-4.311685	4.4994	-0.958	0.3401

Variable	DF	Variable Label
Intercept	1	
HDD_KPC	1	
HDD2_KPC	1	
HDD3_KPC	1	
CDD_KPC	1	
CDD2_KPC	1	
D1	1	
D2	1	
D3	1	
D4	1	
D5	1	
D6	1	
D7	1	
D8	1	
D9	1	

Autoreg Procedure

Variable	DF	Variable Label
DA	1	
DB	1	
T	1	TIME TREND
D92292A	1	BINARY FROM 92:2 TO 92:10
D941ON	1	BINARY 94:1 AND AFTER
D94294C	1	BINARY FROM 94:2 TO 94:12

Estimates of Autocorrelations

```
Lag  Covariance  Correlation -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

  0    115.8201     1.000000 |                    |********************|
  1     33.5338     0.289534 |                    |******              |
  2    2.512041     0.021689 |                    |                    |
  3    -23.9466    -0.206757 |                ****|                    |
  4    -21.6126    -0.186605 |                ****|                    |
  5    -14.7179    -0.127076 |                 ***|                    |
  6    -0.48277    -0.004168 |                    |                    |
  7    -12.4416    -0.107422 |                  **|                    |
  8    -14.2046    -0.122644 |                  **|                    |
  9    -20.0564    -0.173168 |                 ***|                    |
 10    -2.58478    -0.022317 |                    |                    |
 11    23.26135     0.200840 |                    |****                |
 12    18.73715     0.161778 |                    |***                 |
```

Preliminary MSE = 98.69889

Estimates of the Autoregressive Parameters

Lag	Coefficient	Std Error	t Ratio
1	-0.24603153	0.102459	-2.401
2	0.01831785	0.104118	0.176
3	0.19464691	0.104054	1.871
4	0.09421798	0.104753	0.899
5	0.11184222	0.105064	1.065
6	-0.04083158	0.104719	-0.390
7	0.13926515	0.104719	1.330
8	0.05169187	0.105064	0.492
9	0.15502443	0.104753	1.480
10	0.03992783	0.104054	0.384
11	-0.16721919	0.104118	-1.606
12	0.05209498	0.102459	0.508

Autoreg Procedure

Yule-Walker Estimates

SSE	1020.075	DFE	92
MSE	11.08777	Root MSE	3.32983
SBC	803.9596	AIC	701.2865
Reg Rsq	0.9572	Total Rsq	0.9476
Durbin-Watson	1.9813		

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
Intercept	1	-5925.508608	200.4	-29.561	0.0001
HDD_KPC	1	-0.004462	0.0214	-0.208	0.8353
HDD2_KPC	1	0.000036455	0.000034	1.079	0.2835
HDD3_KPC	1	-6.621841E-9	1.693E-8	-0.391	0.6965
CDD_KPC	1	0.098155	0.0225	4.353	0.0001
CDD2_KPC	1	-0.000061183	0.00004	-1.527	0.1302
D1	1	3.531720	1.4954	2.362	0.0203
D2	1	-3.235624	1.4834	-2.181	0.0317
D3	1	1.156326	1.8288	0.632	0.5288
D4	1	-4.142562	2.9421	-1.408	0.1625
D5	1	0.194165	3.9695	0.049	0.9611
D6	1	-8.378346	4.9555	-1.691	0.0943
D7	1	-6.856206	5.3616	-1.279	0.2042
D8	1	-7.537985	5.2126	-1.446	0.1515
D9	1	-2.903293	4.4298	-0.655	0.5138
DA	1	2.908633	2.9226	0.995	0.3222
DB	1	-0.430881	1.9368	-0.222	0.8245
T	1	3.009574	0.1003	30.012	0.0001
D90A914	1	4.962524	1.4833	3.346	0.0012
D961	1	11.776040	3.4701	3.394	0.0010
D97797A	1	4.541229	1.9719	2.303	0.0235
D97B	1	-10.856299	3.5452	-3.062	0.0029
D983	1	-20.073585	3.8959	-5.153	0.0001
D983987	1	3.982208	1.9811	2.010	0.0473

Variable	DF	Variable Label
Intercept	1	
HDD_KPC	1	
HDD2_KPC	1	
HDD3_KPC	1	
CDD_KPC	1	
CDD2_KPC	1	
D1	1	
D2	1	
D3	1	
D4	1	
D5	1	
D6	1	
D7	1	
D8	1	
D9	1	
DA	1	

Autoreg Procedure

Variable	DF	Variable Label
DB	1	
T	1	TIME TREND
D90A914	1	BINARY FROM 90:10 TO 91:4
D961	1	BINARY 96:1
D97797A	1	BINARY FROM 97:7 TO 97:10
D97B	1	BINARY 97:11
D983	1	BINARY 98:3
D983987	1	BINARY FROM 98:3 TO 98:7

Autoreg Procedure

Model: EIX_KPC
Dependent Variable = EIX_KPC OTHER INDUSTRIAL ENERGY

Ordinary Least Squares Estimates

SSE	4562.577	DFE	109
MSE	41.8585	Root MSE	6.469815
SBC	912.8592	AIC	858.6707
Reg Rsq	0.7499	Total Rsq	0.7499
Durbin-Watson	2.0006		

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
Intercept	1	93.654269	14.4953	6.461	0.0001
HDD_KPC	1	0.037976	0.0222	1.707	0.0906
HDD2_KPC	1	-0.000010491	0.000014	-0.736	0.4632
CDD_KPC	1	0.037721	0.0165	2.291	0.0239
D1	1	-4.635725	2.8618	-1.620	0.1082
D2	1	-12.810079	2.9116	-4.400	0.0001
D3	1	-1.463596	3.3767	-0.433	0.6656
D4	1	8.628840	5.2373	1.648	0.1023
D5	1	18.133607	7.5607	2.398	0.0182
D6	1	11.334457	9.5478	1.187	0.2377
D7	1	8.906084	10.3492	0.861	0.3914
D8	1	12.306188	10.0287	1.227	0.2224
D9	1	11.934418	8.6240	1.384	0.1692
DA	1	14.564607	5.3977	2.698	0.0081
DB	1	1.096447	3.5166	0.312	0.7558
FRB331	1	0.357870	0.1062	3.371	0.0010
D927947	1	-11.077362	1.5533	-7.131	0.0001
D955ON	1	5.908763	2.1032	2.809	0.0059
D971ON	1	5.416975	2.2139	2.447	0.0160

Variable	DF	Variable Label
Intercept	1	
HDD_KPC	1	
HDD2_KPC	1	
CDD_KPC	1	
D1	1	
D2	1	
D3	1	
D4	1	
D5	1	
D6	1	
D7	1	
D8	1	
D9	1	
DA	1	
DB	1	
FRB331	1	
D927947	1	BINARY FROM 92:7 TO 94:7

Autoreg Procedure

Variable	DF	Variable Label
D955ON	1	BINARY 95:5 AND AFTER
D971ON	1	BINARY 97:1 AND AFTER

Autoreg Procedure

Yule-Walker Estimates

SSE	10780.82	DFE	95
MSE	113.4823	Root MSE	10.65281
SBC	1091.979	AIC	997.8617
Reg Rsq	0.9196	Total Rsq	0.9532
Durbin-Watson	1.8824		

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
Intercept	1	-7270.913757	1162.9	-6.362	0.0001
HDD_KPC	1	0.026279	0.0647	0.406	0.6857
HDD2_KPC	1	0.000107	0.000101	1.059	0.2924
HDD3_KPC	1	-5.11572E-8	5.043E-8	-1.015	0.3129
CDD_KPC	1	0.124723	0.0691	1.804	0.0743
CDD2_KPC	1	0.000150	0.000123	1.213	0.2281
D1	1	13.321295	4.6401	2.871	0.0050
D2	1	-16.113461	6.2216	-2.590	0.0111
D3	1	-19.858852	7.8656	-2.525	0.0132
D4	1	-37.659349	10.3257	-3.647	0.0004
D5	1	-47.217858	12.7956	-3.690	0.0004
D6	1	-55.881120	15.6764	-3.565	0.0006
D7	1	-41.095201	16.8819	-2.434	0.0168
D8	1	-39.092998	16.6268	-2.351	0.0208
D9	1	-46.404607	14.5836	-3.182	0.0020
DA	1	-44.254628	9.9217	-4.460	0.0001
DB	1	-20.821016	5.8087	-3.584	0.0005
T	1	3.721458	0.5731	6.494	0.0001
D92292A	1	6.254510	3.8632	1.619	0.1088
D9410N	1	9.225095	3.9049	2.362	0.0202
D94294C	1	-5.955672	3.3839	-1.760	0.0816

Variable	DF	Variable Label
Intercept	1	
HDD_KPC	1	
HDD2_KPC	1	
HDD3_KPC	1	
CDD_KPC	1	
CDD2_KPC	1	
D1	1	
D2	1	
D3	1	
D4	1	
D5	1	
D6	1	
D7	1	
D8	1	
D9	1	
DA	1	
DB	1	
T	1	TIME TREND
D92292A	1	BINARY FROM 92:2 TO 92:10

Autoreg Procedure

Variable	DF	Variable Label
D9410N	1	BINARY 94:1 AND AFTER
D94294C	1	BINARY FROM 94:2 TO 94:12

Autoreg Procedure

Model: EC_KPC
Dependent Variable = EC_KPC   COMMERCIAL ENERGY

Ordinary Least Squares Estimates

SSE	1109.958	DFE	104
MSE	10.67267	Root MSE	3.266905
SBC	756.183	AIC	687.7343
Reg Rsq	0.9430	Total Rsq	0.9430
Durbin-Watson	1.9427		

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
Intercept	1	-5887.974579	218.1	-26.996	0.0001
HDD_KPC	1	-0.007360	0.0216	-0.341	0.7340
HDD2_KPC	1	0.000041421	0.000034	1.209	0.2295
HDD3_KPC	1	-9.447675E-9	1.716E-8	-0.550	0.5832
CDD_KPC	1	0.087916	0.0229	3.836	0.0002
CDD2_KPC	1	-0.000048445	0.000041	-1.192	0.2358
D1	1	3.652486	1.4714	2.482	0.0147
D2	1	-3.230858	1.4747	-2.191	0.0307
D3	1	1.135793	1.8479	0.615	0.5401
D4	1	-3.940388	2.9145	-1.352	0.1793
D5	1	0.671132	3.9447	0.170	0.8652
D6	1	-7.105229	5.0299	-1.413	0.1608
D7	1	-5.285335	5.3577	-0.987	0.3262
D8	1	-6.267660	5.2482	-1.194	0.2351
D9	1	-2.259110	4.5197	-0.500	0.6182
DA	1	2.964472	2.9815	0.994	0.3224
DB	1	-0.292178	1.9502	-0.150	0.8812
T	1	2.991010	0.1092	27.401	0.0001
D90A914	1	5.299587	1.3748	3.855	0.0002
D961	1	11.265343	3.4854	3.232	0.0016
D97797A	1	5.175237	1.8344	2.821	0.0057
D97B	1	-11.353226	3.5208	-3.225	0.0017
D983	1	-17.829941	3.9329	-4.534	0.0001
D983987	1	3.360546	1.8356	1.831	0.0700

Variable	DF	Variable Label
Intercept	1	
HDD_KPC	1	
HDD2_KPC	1	
HDD3_KPC	1	
CDD_KPC	1	
CDD2_KPC	1	
D1	1	
D2	1	
D3	1	
D4	1	
D5	1	
D6	1	

Autoreg Procedure

Variable	DF	Variable Label
D7	1	
D8	1	
D9	1	
DA	1	
DB	1	
T	1	TIME TREND
D90A914	1	BINARY FROM 90:10 TO 91:4
D961	1	BINARY 96:1
D97797A	1	BINARY FROM 97:7 TO 97:10
D97B	1	BINARY 97:11
D983	1	BINARY 98:3
D983987	1	BINARY FROM 98:3 TO 98:7

Estimates of Autocorrelations

```
Lag  Covariance  Correlation -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

  0    8.671545     1.000000 |                    |********************|
  1    0.168302     0.019408 |                    |                    |
  2    0.296082     0.034144 |                    |*                   |
  3    1.263519     0.145709 |                    |***                 |
  4    -0.36784    -0.042420 |                   *|                    |
  5     -1.2861    -0.148313 |                 ***|                    |
  6    0.262198     0.030237 |                    |*                   |
  7    -0.88316    -0.101846 |                  **|                    |
  8    -0.87925    -0.101395 |                  **|                    |
  9    -0.53737    -0.061969 |                   *|                    |
 10    0.071662     0.008264 |                    |                    |
 11    -0.02741    -0.003161 |                    |                    |
 12    -0.12957    -0.014942 |                    |                    |
```

Preliminary MSE = 8.087739

Estimates of the Autoregressive Parameters

Lag	Coefficient	Std Error	t Ratio
1	-0.01004747	0.104197	-0.096
2	-0.04339267	0.104163	-0.417
3	-0.13700477	0.104250	-1.314
4	0.04942609	0.104933	0.471
5	0.14998232	0.104855	1.431
6	-0.03872866	0.105647	-0.367
7	0.08201124	0.105647	0.776
8	0.06620019	0.104833	0.631
9	0.07237537	0.104933	0.690
10	-0.02437735	0.104250	-0.234
11	-0.02740729	0.104163	-0.263
12	0.03402648	0.104197	0.327

Autoreg Procedure

Model: EIM_KPC
Dependent Variable = EIM_KPC   MINE POWER ENERGY

Ordinary Least Squares Estimates

SSE	1817.354	DFE	107
MSE	16.98462	Root MSE	4.12124
SBC	804.7385	AIC	744.8459
Reg Rsq	0.8866	Total Rsq	0.8866
Durbin-Watson	1.7191		

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
Intercept	1	-1546.827529	324.0	-4.775	0.0001
HDD_KPC	1	0.028570	0.0146	1.962	0.0523
HDD2_KPC	1	-0.000008243	9.297E-6	-0.887	0.3773
CDD_KPC	1	-0.004655	0.0104	-0.448	0.6550
D1	1	-2.636094	1.9772	-1.333	0.1853
D2	1	-2.094498	1.8962	-1.105	0.2718
D3	1	4.470313	2.2906	1.952	0.0536
D4	1	-2.045641	3.4769	-0.588	0.5575
D5	1	1.020796	5.0223	0.203	0.8393
D6	1	-0.117198	6.3477	-0.018	0.9853
D7	1	-8.492468	6.8591	-1.238	0.2184
D8	1	6.495584	6.6668	0.974	0.3321
D9	1	-4.316800	5.6973	-0.758	0.4503
DA	1	4.922775	3.5429	1.389	0.1676
DB	1	0.035118	2.2814	0.015	0.9877
T	1	0.812726	0.1634	4.973	0.0001
D899ON	1	8.480778	1.3697	6.192	0.0001
D95C	1	-33.676665	4.4167	-7.625	0.0001
D961	1	-20.561288	4.4103	-4.662	0.0001
D963	1	17.940291	4.4406	4.040	0.0001
D981	1	-16.066266	4.5262	-3.550	0.0006

Variable	DF	Variable Label
Intercept	1	
HDD_KPC	1	
HDD2_KPC	1	
CDD_KPC	1	
D1	1	
D2	1	
D3	1	
D4	1	
D5	1	
D6	1	
D7	1	
D8	1	
D9	1	
DA	1	
DB	1	

Autoreg Procedure

Variable	DF	Variable Label
T	1	TIME TREND
D899ON	1	BINARY 89:9 AND AFTER
D95C	1	BINARY 95:12
D961	1	BINARY 96:1
D963	1	BINARY 96:3
D981	1	BINARY 98:1

Estimates of Autocorrelations

```
Lag  Covariance  Correlation -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

  0    14.19808     1.000000 |                    |********************|
  1    1.928069     0.135798 |                    |***                 |
  2     2.90661     0.204719 |                    |****                |
  3    1.660065     0.116922 |                    |**                  |
  4    1.420562     0.100053 |                    |**                  |
  5    -0.72225    -0.050870 |                   *|                    |
  6    0.162185     0.011423 |                    |                    |
  7    0.878979     0.061908 |                    |*                   |
  8    -1.26626    -0.089185 |                  **|                    |
  9    -0.53063    -0.037373 |                   *|                    |
 10     -0.3104    -0.021862 |                    |                    |
 11     0.40108     0.028249 |                    |*                   |
 12    -0.55279    -0.038934 |                   *|                    |
```

Preliminary MSE = 12.98408

Estimates of the Autoregressive Parameters

Lag	Coefficient	Std Error	t Ratio
1	-0.10300293	0.102591	-1.004
2	-0.19398061	0.102969	-1.884
3	-0.07568845	0.104875	-0.722
4	-0.04275898	0.105059	-0.407
5	0.11017504	0.104656	1.053
6	-0.01048768	0.104885	-0.100
7	-0.09594996	0.104808	-0.916
8	0.09932428	0.104656	0.949
9	0.04518473	0.105059	0.430
10	0.00268661	0.104875	0.026
11	-0.05681138	0.102969	-0.552
12	0.01132281	0.102591	0.110

Autoreg Procedure

Yule-Walker Estimates

SSE	1617.684	DFE	95
MSE	17.02825	Root MSE	4.126531
SBC	848.4148	AIC	754.2978
Reg Rsq	0.8789	Total Rsq	0.8990
Durbin-Watson	1.9690		

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
Intercept	1	-1612.121859	446.1	-3.613	0.0005
HDD_KPC	1	0.032992	0.0139	2.375	0.0196
HDD2_KPC	1	-0.000009382	8.752E-6	-1.072	0.2864
CDD_KPC	1	0.000263	0.0105	0.025	0.9800
D1	1	-3.212018	1.8117	-1.773	0.0794
D2	1	-2.102654	1.7429	-1.206	0.2307
D3	1	4.770044	2.2275	2.141	0.0348
D4	1	-0.832096	3.4174	-0.243	0.8082
D5	1	2.580854	4.9017	0.527	0.5998
D6	1	1.243137	6.2293	0.200	0.8422
D7	1	-7.615907	6.7867	-1.122	0.2646
D8	1	7.576316	6.5711	1.153	0.2518
D9	1	-2.530006	5.5440	-0.456	0.6492
DA	1	6.527377	3.3702	1.937	0.0557
DB	1	0.664660	2.1236	0.313	0.7550
T	1	0.844335	0.2247	3.758	0.0003
D899ON	1	8.119568	1.8574	4.372	0.0001
D95C	1	-35.383126	4.2376	-8.350	0.0001
D961	1	-18.857747	4.3052	-4.380	0.0001
D963	1	18.346492	4.3560	4.212	0.0001
D981	1	-17.270292	4.3113	-4.006	0.0001

Variable	DF	Variable Label
Intercept	1	
HDD_KPC	1	
HDD2_KPC	1	
CDD_KPC	1	
D1	1	
D2	1	
D3	1	
D4	1	
D5	1	
D6	1	
D7	1	
D8	1	
D9	1	
DA	1	
DB	1	
T	1	TIME TREND
D899ON	1	BINARY 89:9 AND AFTER
D95C	1	BINARY 95:12
D961	1	BINARY 96:1

Autoreg Procedure

Variable	DF	Variable Label
D963	1	BINARY 96:3
D981	1	BINARY 98:1

Autoreg Procedure

Model: EUL_KPC
Dependent Variable = EUL_KPC STREET LIGHTING ENERGY

Ordinary Least Squares Estimates

SSE	0.142026	DFE	113
MSE	0.001257	Root MSE	0.035452
SBC	-434.854	AIC	-477.635
Reg Rsq	0.9370	Total Rsq	0.9370
Durbin-Watson	2.3351		

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
Intercept	1	-27.430668	3.3838	-8.106	0.0001
D1	1	0.005658	0.0156	0.364	0.7169
D2	1	-0.175445	0.0154	-11.380	0.0001
D3	1	-0.143829	0.0156	-9.243	0.0001
D4	1	-0.249454	0.0156	-16.030	0.0001
D5	1	-0.289202	0.0156	-18.582	0.0001
D6	1	-0.353641	0.0156	-22.740	0.0001
D7	1	-0.310185	0.0155	-19.950	0.0001
D8	1	-0.265909	0.0155	-17.156	0.0001
D9	1	-0.227927	0.0159	-14.371	0.0001
DA	1	-0.086970	0.0159	-5.485	0.0001
DB	1	-0.047612	0.0159	-2.990	0.0034
T	1	0.014241	0.00170	8.383	0.0001
D956ON	1	0.027265	0.0119	2.287	0.0241
D961967	1	-0.028468	0.0152	-1.874	0.0636

Variable	DF	Variable Label
Intercept	1	
D1	1	
D2	1	
D3	1	
D4	1	
D5	1	
D6	1	
D7	1	
D8	1	
D9	1	
DA	1	
DB	1	
T	1	TIME TREND
D956ON	1	BINARY 95:6 AND AFTER
D961967	1	BINARY FROM 96:1 TO 96:7

Autoreg Procedure

Estimates of Autocorrelations

```
Lag  Covariance  Correlation -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

  0     0.00111     1.000000 |                    |********************|
  1    -0.00019    -0.167961 |                 ***|                    |
  2    0.000139     0.124900 |                    |**                  |
  3    0.000163     0.146805 |                    |***                 |
  4    -0.00001    -0.011966 |                    |                    |
  5    6.469E-6     0.005830 |                    |                    |
  6    0.000136     0.122780 |                    |**                  |
  7    0.000088     0.079127 |                    |**                  |
  8    5.833E-6     0.005257 |                    |                    |
  9    0.000051     0.045987 |                    |*                   |
 10    -0.00003    -0.024002 |                    |                    |
 11    0.000161     0.144802 |                    |***                 |
 12    -0.00025    -0.229104 |               *****|                    |
```

Preliminary MSE = 0.000933

Estimates of the Autoregressive Parameters

Lag	Coefficient	Std Error	t Ratio
1	0.14755596	0.097289	1.517
2	-0.13045742	0.097802	-1.334
3	-0.17633932	0.098668	-1.787
4	0.02707254	0.100204	0.270
5	0.02854734	0.100233	0.285
6	-0.14814496	0.099390	-1.490
7	-0.13281687	0.099390	-1.336
8	0.01209521	0.100233	0.121
9	0.00873906	0.100204	0.087
10	0.00170075	0.098668	0.017
11	-0.10802533	0.097802	-1.105
12	0.20979959	0.097289	2.156

Yule-Walker Estimates

SSE	0.116080	DFE	101
MSE	0.001149	Root MSE	0.033903
SBC	-401.291	AIC	-478.296
Reg Rsq	0.9679	Total Rsq	0.9485
Durbin-Watson	2.0499		

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
Intercept	1	-23.384192	4.0664	-5.751	0.0001
D1	1	0.004489	0.0129	0.347	0.7294
D2	1	-0.177708	0.0121	-14.711	0.0001
D3	1	-0.144094	0.0118	-12.216	0.0001
D4	1	-0.249977	0.0129	-19.313	0.0001
D5	1	-0.289629	0.0123	-23.471	0.0001

Autoreg Procedure

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
D6	1	-0.354975	0.0113	-31.553	0.0001
D7	1	-0.311058	0.0123	-25.259	0.0001
D8	1	-0.266971	0.0129	-20.730	0.0001
D9	1	-0.229830	0.0120	-19.200	0.0001
DA	1	-0.089729	0.0123	-7.275	0.0001
DB	1	-0.048069	0.0132	-3.640	0.0004
T	1	0.012210	0.00204	5.981	0.0001
D956ON	1	0.042285	0.0136	3.112	0.0024
D961967	1	-0.035966	0.0138	-2.610	0.0104

Variable	DF	Variable Label
Intercept	1	
D1	1	
D2	1	
D3	1	
D4	1	
D5	1	
D6	1	
D7	1	
D8	1	
D9	1	
DA	1	
DB	1	
T	1	TIME TREND
D956ON	1	BINARY 95:6 AND AFTER
D961967	1	BINARY FROM 96:1 TO 96:7

Autoreg Procedure

Model: EOM_KPC
Dependent Variable = EOM_KPC MUNI ENERGY

Ordinary Least Squares Estimates

SSE	27.5072	DFE	91
MSE	0.302277	Root MSE	0.549797
SBC	345.9628	AIC	240.4377
Reg Rsq	0.9693	Total Rsq	0.9693
Durbin-Watson	2.3950		

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
Intercept	1	-150.896577	65.9307	-2.289	0.0244
HDD_KPC	1	0.000109	0.00198	0.055	0.9565
HDD2_KPC	1	0.000000728	1.281E-6	0.568	0.5712
CDD_KPC	1	0.004665	0.00154	3.037	0.0031
D1	1	-0.114094	0.3369	-0.339	0.7357
D2	1	0.265338	0.3271	0.811	0.4193
D3	1	0.379919	0.3710	1.024	0.3085
D4	1	-0.104935	0.5164	-0.203	0.8394
D5	1	-0.538077	0.7142	-0.753	0.4531
D6	1	-0.923072	0.8672	-1.064	0.2900
D7	1	-1.169173	0.9400	-1.244	0.2168
D8	1	-1.109642	0.9007	-1.232	0.2211
D9	1	-0.927040	0.7728	-1.200	0.2334
DA	1	-0.235483	0.5008	-0.470	0.6394
DB	1	-0.121225	0.3011	-0.310	0.7512
DM941ON	1	0.465692	0.5301	0.870	0.3820
DM942ON	1	-0.737506	0.5047	-1.461	0.1474
DM943ON	1	-0.864557	0.5093	-1.697	0.0930
DM944ON	1	-2.357335	0.4959	-4.754	0.0001
DM945ON	1	-0.768429	0.4979	-1.543	0.1262
DM946ON	1	-0.769775	0.4955	-1.553	0.1238
DM947ON	1	-1.239116	0.5325	-2.328	0.0221
DM948ON	1	0.534541	0.5040	1.061	0.2917
DM949ON	1	-0.977613	0.5158	-1.895	0.0612
DM94AON	1	-1.358898	0.5071	-2.680	0.0087
DM94BON	1	-0.724418	0.5093	-1.422	0.1585
T	1	0.076667	0.0331	2.315	0.0229
D894896	1	1.973574	0.3620	5.452	0.0001
D911	1	2.620860	0.6038	4.341	0.0001
D961	1	-5.135187	0.6198	-8.292	0.0001
D962	1	7.138525	0.6015	11.868	0.0001
D967971	1	0.385369	0.2452	1.572	0.1195
D977	1	-6.013160	0.6461	-9.307	0.0001
D978	1	6.807078	0.6425	10.594	0.0001
D983	1	2.389659	0.6237	3.832	0.0002
D987	1	1.485728	0.6543	2.271	0.0255
T941ON	1	0.002345	0.000197	11.905	0.0001

Autoreg Procedure

Variable	DF	Variable Label
Intercept	1	
HDD_KPC	1	
HDD2_KPC	1	
CDD_KPC	1	
D1	1	
D2	1	
D3	1	
D4	1	
D5	1	
D6	1	
D7	1	
D8	1	
D9	1	
DA	1	
DB	1	
DM941ON	1	BINARY MONTH 1 94:1 AND AFTER
DM942ON	1	BINARY MONTH 2 94:2 AND AFTER
DM943ON	1	BINARY MONTH 3 94:3 AND AFTER
DM944ON	1	BINARY MONTH 4 94:4 AND AFTER
DM945ON	1	BINARY MONTH 5 94:5 AND AFTER
DM946ON	1	BINARY MONTH 6 94:6 AND AFTER
DM947ON	1	BINARY MONTH 7 94:7 AND AFTER
DM948ON	1	BINARY MONTH 8 94:8 AND AFTER
DM949ON	1	BINARY MONTH 9 94:9 AND AFTER
DM94AON	1	BINARY MONTH 10 94:10 AND AFTER
DM94BON	1	BINARY MONTH 11 94:11 AND AFTER
T	1	TIME TREND
D894896	1	BINARY FROM 89:4 TO 89:6
D911	1	BINARY 91:1
D961	1	BINARY 96:1
D962	1	BINARY 96:2
D967971	1	BINARY FROM 96:7 TO 97:1
D977	1	BINARY 97:7
D978	1	BINARY 97:8
D983	1	BINARY 98:3
D987	1	BINARY 98:7
T941ON	1	TREND 94:1 AND AFTER

Autoreg Procedure

Estimates of Autocorrelations

```
Lag  Covariance  Correlation -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

  0      0.2149     1.000000 |                    |********************|
  1     -0.0435    -0.202453 |                ****|                    |
  2    -0.03369    -0.156759 |                 ***|                    |
  3    0.048999     0.228007 |                    |*****               |
  4     -0.0281    -0.130739 |                 ***|                    |
  5     -0.0074    -0.034442 |                   *|                    |
  6    -0.00114    -0.005305 |                    |                    |
  7    0.011586     0.053914 |                    |*                   |
  8    -0.01985    -0.092378 |                  **|                    |
  9    -0.00523    -0.024325 |                    |                    |
 10    0.020875     0.097138 |                    |**                  |
 11    -0.01004    -0.046721 |                   *|                    |
 12    -0.04492    -0.209034 |                ****|                    |
```

Preliminary MSE = 0.175248

Estimates of the Autoregressive Parameters

Lag	Coefficient	Std Error	t Ratio
1	0.18398454	0.109248	1.684
2	0.18190364	0.111139	1.637
3	-0.15264958	0.112988	-1.351
4	0.15106838	0.114268	1.322
5	-0.00539911	0.114576	-0.047
6	0.11248103	0.114452	0.983
7	-0.04769146	0.114452	-0.417
8	0.13135805	0.114576	1.146
9	-0.01767283	0.114268	-0.155
10	0.01879307	0.112988	0.166
11	0.02816262	0.111139	0.253
12	0.23929747	0.109248	2.191

Yule-Walker Estimates

SSE	21.18459	DFE	79
MSE	0.268159	Root MSE	0.517841
SBC	371.8884	AIC	232.139
Reg Rsq	0.9899	Total Rsq	0.9768
Durbin-Watson	2.1109		

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
Intercept	1	-147.428588	42.8756	-3.439	0.0009
HDD_KPC	1	0.000128	0.00184	0.070	0.9448
HDD2_KPC	1	0.000000596	1.222E-6	0.488	0.6272
CDD_KPC	1	0.004311	0.00139	3.093	0.0027
D1	1	-0.142593	0.3142	-0.454	0.6512
D2	1	0.256258	0.2878	0.892	0.3751

Autoreg Procedure

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
D3	1	0.360864	0.2997	1.204	0.2321
D4	1	-0.151729	0.4581	-0.331	0.7414
D5	1	-0.588157	0.6162	-0.954	0.3428
D6	1	-0.909529	0.7657	-1.188	0.2385
D7	1	-1.048856	0.8222	-1.276	0.2058
D8	1	-1.072963	0.7961	-1.348	0.1816
D9	1	-0.966769	0.6579	-1.469	0.1457
DA	1	-0.287443	0.4360	-0.659	0.5117
DB	1	-0.159464	0.3482	-0.458	0.6482
DM941ON	1	0.424799	0.5022	0.846	0.4002
DM942ON	1	-0.721063	0.4505	-1.601	0.1135
DM943ON	1	-0.819878	0.4096	-2.001	0.0488
DM944ON	1	-2.338280	0.4655	-5.024	0.0001
DM945ON	1	-0.768044	0.4253	-1.806	0.0747
DM946ON	1	-0.828847	0.4421	-1.875	0.0645
DM947ON	1	-1.335981	0.4527	-2.951	0.0042
DM948ON	1	0.435570	0.4778	0.912	0.3648
DM949ON	1	-0.995358	0.4091	-2.433	0.0172
DM94AON	1	-1.393450	0.4610	-3.023	0.0034
DM94BON	1	-0.802930	0.4826	-1.664	0.1001
T	1	0.074959	0.0216	3.476	0.0008
D894896	1	1.984529	0.3081	6.442	0.0001
D911	1	2.915579	0.5494	5.307	0.0001
D961	1	-4.771440	0.5782	-8.253	0.0001
D962	1	7.046462	0.5629	12.518	0.0001
D967971	1	0.510613	0.1882	2.713	0.0082
D977	1	-6.408024	0.5902	-10.857	0.0001
D978	1	7.121367	0.6121	11.634	0.0001
D983	1	1.924467	0.5769	3.336	0.0013
D987	1	1.683398	0.6003	2.804	0.0063
T941ON	1	0.002362	0.000164	14.439	0.0001

Variable	DF	Variable Label
Intercept	1	
HDD_KPC	1	
HDD2_KPC	1	
CDD_KPC	1	
D1	1	
D2	1	
D3	1	
D4	1	
D5	1	
D6	1	
D7	1	
D8	1	
D9	1	
DA	1	
DB	1	
DM941ON	1	BINARY MONTH 1 94:1 AND AFTER
DM942ON	1	BINARY MONTH 2 94:2 AND AFTER
DM943ON	1	BINARY MONTH 3 94:3 AND AFTER

Autoreg Procedure

Variable	DF	Variable Label
DM944ON	1	BINARY MONTH 4 94:4 AND AFTER
DM945ON	1	BINARY MONTH 5 94:5 AND AFTER
DM946ON	1	BINARY MONTH 6 94:6 AND AFTER
DM947ON	1	BINARY MONTH 7 94:7 AND AFTER
DM948ON	1	BINARY MONTH 8 94:8 AND AFTER
DM949ON	1	BINARY MONTH 9 94:9 AND AFTER
DM94AON	1	BINARY MONTH 10 94:10 AND AFTER
DM94BON	1	BINARY MONTH 11 94:11 AND AFTER
T	1	TIME TREND
D894896	1	BINARY FROM 89:4 TO 89:6
D911	1	BINARY 91:1
D961	1	BINARY 96:1
D962	1	BINARY 96:2
D967971	1	BINARY FROM 96:7 TO 97:1
D977	1	BINARY 97:7
D978	1	BINARY 97:8
D983	1	BINARY 98:3
D987	1	BINARY 98:7
T941ON	1	TREND 94:1 AND AFTER

SHORT TERM MODELS
BINARY VARIABLES

YEAR	MONTH	DA	DB	D1	D2	D3
1988	1	0	0	1	0.00000	0
1988	2	0	0	0	1.03571	0
1988	3	0	0	0	0.00000	1
1988	4	0	0	0	0.00000	0
1988	5	0	0	0	0.00000	0
1988	6	0	0	0	0.00000	0
1988	7	0	0	0	0.00000	0
1988	8	0	0	0	0.00000	0
1988	9	0	0	0	0.00000	0
1988	10	1	0	0	0.00000	0
1988	11	0	1	0	0.00000	0
1988	12	0	0	0	0.00000	0
1989	1	0	0	1	0.00000	0
1989	2	0	0	0	1.00000	0
1989	3	0	0	0	0.00000	1
1989	4	0	0	0	0.00000	0
1989	5	0	0	0	0.00000	0
1989	6	0	0	0	0.00000	0
1989	7	0	0	0	0.00000	0
1989	8	0	0	0	0.00000	0
1989	9	0	0	0	0.00000	0
1989	10	1	0	0	0.00000	0
1989	11	0	1	0	0.00000	0
1989	12	0	0	0	0.00000	0
1990	1	0	0	1	0.00000	0
1990	2	0	0	0	1.00000	0
1990	3	0	0	0	0.00000	1
1990	4	0	0	0	0.00000	0
1990	5	0	0	0	0.00000	0
1990	6	0	0	0	0.00000	0
1990	7	0	0	0	0.00000	0
1990	8	0	0	0	0.00000	0
1990	9	0	0	0	0.00000	0
1990	10	1	0	0	0.00000	0
1990	11	0	1	0	0.00000	0
1990	12	0	0	0	0.00000	0
1991	1	0	0	1	0.00000	0
1991	2	0	0	0	1.00000	0
1991	3	0	0	0	0.00000	1
1991	4	0	0	0	0.00000	0
1991	5	0	0	0	0.00000	0
1991	6	0	0	0	0.00000	0
1991	7	0	0	0	0.00000	0
1991	8	0	0	0	0.00000	0
1991	9	0	0	0	0.00000	0
1991	10	1	0	0	0.00000	0
1991	11	0	1	0	0.00000	0
1991	12	0	0	0	0.00000	0
1992	1	0	0	1	0.00000	0
1992	2	0	0	0	1.03571	0
1992	3	0	0	0	0.00000	1
1992	4	0	0	0	0.00000	0
1992	5	0	0	0	0.00000	0
1992	6	0	0	0	0.00000	0
1992	7	0	0	0	0.00000	0

SHORT TERM MODELS
BINARY VARIABLES

YEAR	MONTH	DA	DB	D1	D2	D3
1992	8	0	0	0	0.00000	0
1992	9	0	0	0	0.00000	0
1992	10	1	0	0	0.00000	0
1992	11	0	1	0	0.00000	0
1992	12	0	0	0	0.00000	0
1993	1	0	0	1	0.00000	0
1993	2	0	0	0	1.00000	0
1993	3	0	0	0	0.00000	1
1993	4	0	0	0	0.00000	0
1993	5	0	0	0	0.00000	0
1993	6	0	0	0	0.00000	0
1993	7	0	0	0	0.00000	0
1993	8	0	0	0	0.00000	0
1993	9	0	0	0	0.00000	0
1993	10	1	0	0	0.00000	0
1993	11	0	1	0	0.00000	0
1993	12	0	0	0	0.00000	0
1994	1	0	0	1	0.00000	0
1994	2	0	0	0	1.00000	0
1994	3	0	0	0	0.00000	1
1994	4	0	0	0	0.00000	0
1994	5	0	0	0	0.00000	0
1994	6	0	0	0	0.00000	0
1994	7	0	0	0	0.00000	0
1994	8	0	0	0	0.00000	0
1994	9	0	0	0	0.00000	0
1994	10	1	0	0	0.00000	0
1994	11	0	1	0	0.00000	0
1994	12	0	0	0	0.00000	0
1995	1	0	0	1	0.00000	0
1995	2	0	0	0	1.00000	0
1995	3	0	0	0	0.00000	1
1995	4	0	0	0	0.00000	0
1995	5	0	0	0	0.00000	0
1995	6	0	0	0	0.00000	0
1995	7	0	0	0	0.00000	0
1995	8	0	0	0	0.00000	0
1995	9	0	0	0	0.00000	0
1995	10	1	0	0	0.00000	0
1995	11	0	1	0	0.00000	0
1995	12	0	0	0	0.00000	0
1996	1	0	0	1	0.00000	0
1996	2	0	0	0	1.03571	0
1996	3	0	0	0	0.00000	1
1996	4	0	0	0	0.00000	0
1996	5	0	0	0	0.00000	0
1996	6	0	0	0	0.00000	0
1996	7	0	0	0	0.00000	0
1996	8	0	0	0	0.00000	0
1996	9	0	0	0	0.00000	0
1996	10	1	0	0	0.00000	0
1996	11	0	1	0	0.00000	0
1996	12	0	0	0	0.00000	0
1997	1	0	0	1	0.00000	0
1997	2	0	0	0	1.00000	0

SHORT TERM MODELS
BINARY VARIABLES 77

YEAR	MONTH	DA	DB	D1	D2	D3
1997	3	0	0	0	0.00000	1
1997	4	0	0	0	0.00000	0
1997	5	0	0	0	0.00000	0
1997	6	0	0	0	0.00000	0
1997	7	0	0	0	0.00000	0
1997	8	0	0	0	0.00000	0
1997	9	0	0	0	0.00000	0
1997	10	1	0	0	0.00000	0
1997	11	0	1	0	0.00000	0
1997	12	0	0	0	0.00000	0
1998	1	0	0	1	0.00000	0
1998	2	0	0	0	1.00000	0
1998	3	0	0	0	0.00000	1
1998	4	0	0	0	0.00000	0
1998	5	0	0	0	0.00000	0
1998	6	0	0	0	0.00000	0
1998	7	0	0	0	0.00000	0
1998	8	0	0	0	0.00000	0
1998	9	0	0	0	0.00000	0
1998	10	1	0	0	0.00000	0
1998	11	0	1	0	0.00000	0
1998	12	0	0	0	0.00000	0
1999	1	0	0	1	0.00000	0
1999	2	0	0	0	1.00000	0
1999	3	0	0	0	0.00000	1
1999	4	0	0	0	0.00000	0
1999	5	0	0	0	0.00000	0
1999	6	0	0	0	0.00000	0
1999	7	0	0	0	0.00000	0
1999	8	0	0	0	0.00000	0
1999	9	0	0	0	0.00000	0
1999	10	1	0	0	0.00000	0
1999	11	0	1	0	0.00000	0
1999	12	0	0	0	0.00000	0
2000	1	0	0	1	0.00000	0
2000	2	0	0	0	1.03571	0
2000	3	0	0	0	0.00000	1
2000	4	0	0	0	0.00000	0
2000	5	0	0	0	0.00000	0
2000	6	0	0	0	0.00000	0
2000	7	0	0	0	0.00000	0
2000	8	0	0	0	0.00000	0
2000	9	0	0	0	0.00000	0
2000	10	1	0	0	0.00000	0
2000	11	0	1	0	0.00000	0
2000	12	0	0	0	0.00000	0
2001	1	0	0	1	0.00000	0
2001	2	0	0	0	1.00000	0
2001	3	0	0	0	0.00000	1
2001	4	0	0	0	0.00000	0
2001	5	0	0	0	0.00000	0
2001	6	0	0	0	0.00000	0
2001	7	0	0	0	0.00000	0
2001	8	0	0	0	0.00000	0
2001	9	0	0	0	0.00000	0

SHORT TERM MODELS
BINARY VARIABLES 78

YEAR	MONTH	DA	DB	D1	D2	D3
2001	10	1	0	0	0.00000	0
2001	11	0	1	0	0.00000	0
2001	12	0	0	0	0.00000	0
2002	1	0	0	1	0.00000	0
2002	2	0	0	0	1.00000	0
2002	3	0	0	0	0.00000	1
2002	4	0	0	0	0.00000	0
2002	5	0	0	0	0.00000	0
2002	6	0	0	0	0.00000	0
2002	7	0	0	0	0.00000	0
2002	8	0	0	0	0.00000	0
2002	9	0	0	0	0.00000	0
2002	10	1	0	0	0.00000	0
2002	11	0	1	0	0.00000	0
2002	12	0	0	0	0.00000	0
2003	1	0	0	1	0.00000	0
2003	2	0	0	0	1.00000	0
2003	3	0	0	0	0.00000	1
2003	4	0	0	0	0.00000	0
2003	5	0	0	0	0.00000	0
2003	6	0	0	0	0.00000	0
2003	7	0	0	0	0.00000	0
2003	8	0	0	0	0.00000	0
2003	9	0	0	0	0.00000	0
2003	10	1	0	0	0.00000	0
2003	11	0	1	0	0.00000	0
2003	12	0	0	0	0.00000	0
2004	1	0	0	1	0.00000	0
2004	2	0	0	0	1.03571	0
2004	3	0	0	0	0.00000	1
2004	4	0	0	0	0.00000	0
2004	5	0	0	0	0.00000	0
2004	6	0	0	0	0.00000	0
2004	7	0	0	0	0.00000	0
2004	8	0	0	0	0.00000	0
2004	9	0	0	0	0.00000	0
2004	10	1	0	0	0.00000	0
2004	11	0	1	0	0.00000	0
2004	12	0	0	0	0.00000	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

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YEAR	MONTH	D4	D5	D6	D7	D8
1988	1	0	0	0	0	0
1988	2	0	0	0	0	0
1988	3	0	0	0	0	0
1988	4	1	0	0	0	0
1988	5	0	1	0	0	0
1988	6	0	0	1	0	0
1988	7	0	0	0	1	0
1988	8	0	0	0	0	1
1988	9	0	0	0	0	0
1988	10	0	0	0	0	0
1988	11	0	0	0	0	0
1988	12	0	0	0	0	0
1989	1	0	0	0	0	0
1989	2	0	0	0	0	0
1989	3	0	0	0	0	0
1989	4	1	0	0	0	0
1989	5	0	1	0	0	0
1989	6	0	0	1	0	0
1989	7	0	0	0	1	0
1989	8	0	0	0	0	1
1989	9	0	0	0	0	0
1989	10	0	0	0	0	0
1989	11	0	0	0	0	0
1989	12	0	0	0	0	0
1990	1	0	0	0	0	0
1990	2	0	0	0	0	0
1990	3	0	0	0	0	0
1990	4	1	0	0	0	0
1990	5	0	1	0	0	0
1990	6	0	0	1	0	0
1990	7	0	0	0	1	0
1990	8	0	0	0	0	1
1990	9	0	0	0	0	0
1990	10	0	0	0	0	0
1990	11	0	0	0	0	0
1990	12	0	0	0	0	0
1991	1	0	0	0	0	0
1991	2	0	0	0	0	0
1991	3	0	0	0	0	0
1991	4	1	0	0	0	0
1991	5	0	1	0	0	0
1991	6	0	0	1	0	0
1991	7	0	0	0	1	0
1991	8	0	0	0	0	1
1991	9	0	0	0	0	0
1991	10	0	0	0	0	0
1991	11	0	0	0	0	0
1991	12	0	0	0	0	0
1992	1	0	0	0	0	0
1992	2	0	0	0	0	0
1992	3	0	0	0	0	0
1992	4	1	0	0	0	0
1992	5	0	1	0	0	0
1992	6	0	0	1	0	0
1992	7	0	0	0	1	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

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YEAR	MONTH	D4	D5	D6	D7	D8
1992	8	0	0	0	0	1
1992	9	0	0	0	0	0
1992	10	0	0	0	0	0
1992	11	0	0	0	0	0
1992	12	0	0	0	0	0
1993	1	0	0	0	0	0
1993	2	0	0	0	0	0
1993	3	0	0	0	0	0
1993	4	1	0	0	0	0
1993	5	0	1	0	0	0
1993	6	0	0	1	0	0
1993	7	0	0	0	1	0
1993	8	0	0	0	0	1
1993	9	0	0	0	0	0
1993	10	0	0	0	0	0
1993	11	0	0	0	0	0
1993	12	0	0	0	0	0
1994	1	0	0	0	0	0
1994	2	0	0	0	0	0
1994	3	0	0	0	0	0
1994	4	1	0	0	0	0
1994	5	0	1	0	0	0
1994	6	0	0	1	0	0
1994	7	0	0	0	1	0
1994	8	0	0	0	0	1
1994	9	0	0	0	0	0
1994	10	0	0	0	0	0
1994	11	0	0	0	0	0
1994	12	0	0	0	0	0
1995	1	0	0	0	0	0
1995	2	0	0	0	0	0
1995	3	0	0	0	0	0
1995	4	1	0	0	0	0
1995	5	0	1	0	0	0
1995	6	0	0	1	0	0
1995	7	0	0	0	1	0
1995	8	0	0	0	0	1
1995	9	0	0	0	0	0
1995	10	0	0	0	0	0
1995	11	0	0	0	0	0
1995	12	0	0	0	0	0
1996	1	0	0	0	0	0
1996	2	0	0	0	0	0
1996	3	0	0	0	0	0
1996	4	1	0	0	0	0
1996	5	0	1	0	0	0
1996	6	0	0	1	0	0
1996	7	0	0	0	1	0
1996	8	0	0	0	0	1
1996	9	0	0	0	0	0
1996	10	0	0	0	0	0
1996	11	0	0	0	0	0
1996	12	0	0	0	0	0
1997	1	0	0	0	0	0
1997	2	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

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YEAR	MONTH	D4	D5	D6	D7	D8
1997	3	0	0	0	0	0
1997	4	1	0	0	0	0
1997	5	0	1	0	0	0
1997	6	0	0	1	0	0
1997	7	0	0	0	1	0
1997	8	0	0	0	0	1
1997	9	0	0	0	0	0
1997	10	0	0	0	0	0
1997	11	0	0	0	0	0
1997	12	0	0	0	0	0
1998	1	0	0	0	0	0
1998	2	0	0	0	0	0
1998	3	0	0	0	0	0
1998	4	1	0	0	0	0
1998	5	0	1	0	0	0
1998	6	0	0	1	0	0
1998	7	0	0	0	1	0
1998	8	0	0	0	0	1
1998	9	0	0	0	0	0
1998	10	0	0	0	0	0
1998	11	0	0	0	0	0
1998	12	0	0	0	0	0
1999	1	0	0	0	0	0
1999	2	0	0	0	0	0
1999	3	0	0	0	0	0
1999	4	1	0	0	0	0
1999	5	0	1	0	0	0
1999	6	0	0	1	0	0
1999	7	0	0	0	1	0
1999	8	0	0	0	0	1
1999	9	0	0	0	0	0
1999	10	0	0	0	0	0
1999	11	0	0	0	0	0
1999	12	0	0	0	0	0
2000	1	0	0	0	0	0
2000	2	0	0	0	0	0
2000	3	0	0	0	0	0
2000	4	1	0	0	0	0
2000	5	0	1	0	0	0
2000	6	0	0	1	0	0
2000	7	0	0	0	1	0
2000	8	0	0	0	0	1
2000	9	0	0	0	0	0
2000	10	0	0	0	0	0
2000	11	0	0	0	0	0
2000	12	0	0	0	0	0
2001	1	0	0	0	0	0
2001	2	0	0	0	0	0
2001	3	0	0	0	0	0
2001	4	1	0	0	0	0
2001	5	0	1	0	0	0
2001	6	0	0	1	0	0
2001	7	0	0	0	1	0
2001	8	0	0	0	0	1
2001	9	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

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YEAR	MONTH	D4	D5	D6	D7	D8
2001	10	0	0	0	0	0
2001	11	0	0	0	0	0
2001	12	0	0	0	0	0
2002	1	0	0	0	0	0
2002	2	0	0	0	0	0
2002	3	0	0	0	0	0
2002	4	1	0	0	0	0
2002	5	0	1	0	0	0
2002	6	0	0	1	0	0
2002	7	0	0	0	1	0
2002	8	0	0	0	0	1
2002	9	0	0	0	0	0
2002	10	0	0	0	0	0
2002	11	0	0	0	0	0
2002	12	0	0	0	0	0
2003	1	0	0	0	0	0
2003	2	0	0	0	0	0
2003	3	0	0	0	0	0
2003	4	1	0	0	0	0
2003	5	0	1	0	0	0
2003	6	0	0	1	0	0
2003	7	0	0	0	1	0
2003	8	0	0	0	0	1
2003	9	0	0	0	0	0
2003	10	0	0	0	0	0
2003	11	0	0	0	0	0
2003	12	0	0	0	0	0
2004	1	0	0	0	0	0
2004	2	0	0	0	0	0
2004	3	0	0	0	0	0
2004	4	1	0	0	0	0
2004	5	0	1	0	0	0
2004	6	0	0	1	0	0
2004	7	0	0	0	1	0
2004	8	0	0	0	0	1
2004	9	0	0	0	0	0
2004	10	0	0	0	0	0
2004	11	0	0	0	0	0
2004	12	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D9	D928939	D935941	D963	D967973
1988	1	0	0	0	0	0
1988	2	0	0	0	0	0
1988	3	0	0	0	0	0
1988	4	0	0	0	0	0
1988	5	0	0	0	0	0
1988	6	0	0	0	0	0
1988	7	0	0	0	0	0
1988	8	0	0	0	0	0
1988	9	1	0	0	0	0
1988	10	0	0	0	0	0
1988	11	0	0	0	0	0
1988	12	0	0	0	0	0
1989	1	0	0	0	0	0
1989	2	0	0	0	0	0
1989	3	0	0	0	0	0
1989	4	0	0	0	0	0
1989	5	0	0	0	0	0
1989	6	0	0	0	0	0
1989	7	0	0	0	0	0
1989	8	0	0	0	0	0
1989	9	1	0	0	0	0
1989	10	0	0	0	0	0
1989	11	0	0	0	0	0
1989	12	0	0	0	0	0
1990	1	0	0	0	0	0
1990	2	0	0	0	0	0
1990	3	0	0	0	0	0
1990	4	0	0	0	0	0
1990	5	0	0	0	0	0
1990	6	0	0	0	0	0
1990	7	0	0	0	0	0
1990	8	0	0	0	0	0
1990	9	1	0	0	0	0
1990	10	0	0	0	0	0
1990	11	0	0	0	0	0
1990	12	0	0	0	0	0
1991	1	0	0	0	0	0
1991	2	0	0	0	0	0
1991	3	0	0	0	0	0
1991	4	0	0	0	0	0
1991	5	0	0	0	0	0
1991	6	0	0	0	0	0
1991	7	0	0	0	0	0
1991	8	0	0	0	0	0
1991	9	1	0	0	0	0
1991	10	0	0	0	0	0
1991	11	0	0	0	0	0
1991	12	0	0	0	0	0
1992	1	0	0	0	0	0
1992	2	0	0	0	0	0
1992	3	0	0	0	0	0
1992	4	0	0	0	0	0
1992	5	0	0	0	0	0
1992	6	0	0	0	0	0
1992	7	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D9	D928939	D935941	D963	D967973
1992	8	0	1	0	0	0
1992	9	1	1	0	0	0
1992	10	0	1	0	0	0
1992	11	0	1	0	0	0
1992	12	0	1	0	0	0
1993	1	0	1	0	0	0
1993	2	0	1	0	0	0
1993	3	0	1	0	0	0
1993	4	0	1	0	0	0
1993	5	0	1	1	0	0
1993	6	0	1	1	0	0
1993	7	0	1	1	0	0
1993	8	0	1	1	0	0
1993	9	1	1	1	0	0
1993	10	0	0	1	0	0
1993	11	0	0	1	0	0
1993	12	0	0	1	0	0
1994	1	0	0	1	0	0
1994	2	0	0	0	0	0
1994	3	0	0	0	0	0
1994	4	0	0	0	0	0
1994	5	0	0	0	0	0
1994	6	0	0	0	0	0
1994	7	0	0	0	0	0
1994	8	0	0	0	0	0
1994	9	1	0	0	0	0
1994	10	0	0	0	0	0
1994	11	0	0	0	0	0
1994	12	0	0	0	0	0
1995	1	0	0	0	0	0
1995	2	0	0	0	0	0
1995	3	0	0	0	0	0
1995	4	0	0	0	0	0
1995	5	0	0	0	0	0
1995	6	0	0	0	0	0
1995	7	0	0	0	0	0
1995	8	0	0	0	0	0
1995	9	1	0	0	0	0
1995	10	0	0	0	0	0
1995	11	0	0	0	0	0
1995	12	0	0	0	0	0
1996	1	0	0	0	0	0
1996	2	0	0	0	0	0
1996	3	0	0	0	1	0
1996	4	0	0	0	0	0
1996	5	0	0	0	0	0
1996	6	0	0	0	0	0
1996	7	0	0	0	0	1
1996	8	0	0	0	0	1
1996	9	1	0	0	0	1
1996	10	0	0	0	0	1
1996	11	0	0	0	0	1
1996	12	0	0	0	0	1
1997	1	0	0	0	0	1
1997	2	0	0	0	0	1

SHORT TERM MODELS 85
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D9	D928939	D935941	D963	D967973
1997	3	0	0	0	0	1
1997	4	0	0	0	0	0
1997	5	0	0	0	0	0
1997	6	0	0	0	0	0
1997	7	0	0	0	0	0
1997	8	0	0	0	0	0
1997	9	1	0	0	0	0
1997	10	0	0	0	0	0
1997	11	0	0	0	0	0
1997	12	0	0	0	0	0
1998	1	0	0	0	0	0
1998	2	0	0	0	0	0
1998	3	0	0	0	0	0
1998	4	0	0	0	0	0
1998	5	0	0	0	0	0
1998	6	0	0	0	0	0
1998	7	0	0	0	0	0
1998	8	0	0	0	0	0
1998	9	1	0	0	0	0
1998	10	0	0	0	0	0
1998	11	0	0	0	0	0
1998	12	0	0	0	0	0
1999	1	0	0	0	0	0
1999	2	0	0	0	0	0
1999	3	0	0	0	0	0
1999	4	0	0	0	0	0
1999	5	0	0	0	0	0
1999	6	0	0	0	0	0
1999	7	0	0	0	0	0
1999	8	0	0	0	0	0
1999	9	1	0	0	0	0
1999	10	0	0	0	0	0
1999	11	0	0	0	0	0
1999	12	0	0	0	0	0
2000	1	0	0	0	0	0
2000	2	0	0	0	0	0
2000	3	0	0	0	0	0
2000	4	0	0	0	0	0
2000	5	0	0	0	0	0
2000	6	0	0	0	0	0
2000	7	0	0	0	0	0
2000	8	0	0	0	0	0
2000	9	1	0	0	0	0
2000	10	0	0	0	0	0
2000	11	0	0	0	0	0
2000	12	0	0	0	0	0
2001	1	0	0	0	0	0
2001	2	0	0	0	0	0
2001	3	0	0	0	0	0
2001	4	0	0	0	0	0
2001	5	0	0	0	0	0
2001	6	0	0	0	0	0
2001	7	0	0	0	0	0
2001	8	0	0	0	0	0
2001	9	1	0	0	0	0

SHORT TERM MODELS 86
BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D9	D928939	D935941	D963	D967973
2001	10	0	0	0	0	0
2001	11	0	0	0	0	0
2001	12	0	0	0	0	0
2002	1	0	0	0	0	0
2002	2	0	0	0	0	0
2002	3	0	0	0	0	0
2002	4	0	0	0	0	0
2002	5	0	0	0	0	0
2002	6	0	0	0	0	0
2002	7	0	0	0	0	0
2002	8	0	0	0	0	0
2002	9	1	0	0	0	0
2002	10	0	0	0	0	0
2002	11	0	0	0	0	0
2002	12	0	0	0	0	0
2003	1	0	0	0	0	0
2003	2	0	0	0	0	0
2003	3	0	0	0	0	0
2003	4	0	0	0	0	0
2003	5	0	0	0	0	0
2003	6	0	0	0	0	0
2003	7	0	0	0	0	0
2003	8	0	0	0	0	0
2003	9	1	0	0	0	0
2003	10	0	0	0	0	0
2003	11	0	0	0	0	0
2003	12	0	0	0	0	0
2004	1	0	0	0	0	0
2004	2	0	0	0	0	0
2004	3	0	0	0	0	0
2004	4	0	0	0	0	0
2004	5	0	0	0	0	0
2004	6	0	0	0	0	0
2004	7	0	0	0	0	0
2004	8	0	0	0	0	0
2004	9	1	0	0	0	0
2004	10	0	0	0	0	0
2004	11	0	0	0	0	0
2004	12	0	0	0	0	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

87

YEAR	MONTH	D97897C
1988	1	0
1988	2	0
1988	3	0
1988	4	0
1988	5	0
1988	6	0
1988	7	0
1988	8	0
1988	9	0
1988	10	0
1988	11	0
1988	12	0
1989	1	0
1989	2	0
1989	3	0
1989	4	0
1989	5	0
1989	6	0
1989	7	0
1989	8	0
1989	9	0
1989	10	0
1989	11	0
1989	12	0
1990	1	0
1990	2	0
1990	3	0
1990	4	0
1990	5	0
1990	6	0
1990	7	0
1990	8	0
1990	9	0
1990	10	0
1990	11	0
1990	12	0
1991	1	0
1991	2	0
1991	3	0
1991	4	0
1991	5	0
1991	6	0
1991	7	0
1991	8	0
1991	9	0
1991	10	0
1991	11	0
1991	12	0
1992	1	0
1992	2	0
1992	3	0
1992	4	0
1992	5	0
1992	6	0
1992	7	0

SHORT TERM MODELS
BINARY VARIABLES -- CONTINUED

88

YEAR	MONTH	D97897C
1992	8	0
1992	9	0
1992	10	0
1992	11	0
1992	12	0
1993	1	0
1993	2	0
1993	3	0
1993	4	0
1993	5	0
1993	6	0
1993	7	0
1993	8	0
1993	9	0
1993	10	0
1993	11	0
1993	12	0
1994	1	0
1994	2	0
1994	3	0
1994	4	0
1994	5	0
1994	6	0
1994	7	0
1994	8	0
1994	9	0
1994	10	0
1994	11	0
1994	12	0
1995	1	0
1995	2	0
1995	3	0
1995	4	0
1995	5	0
1995	6	0
1995	7	0
1995	8	0
1995	9	0
1995	10	0
1995	11	0
1995	12	0
1996	1	0
1996	2	0
1996	3	0
1996	4	0
1996	5	0
1996	6	0
1996	7	0
1996	8	0
1996	9	0
1996	10	0
1996	11	0
1996	12	0
1997	1	0
1997	2	0

SHORT TERM MODELS

BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D97897C
1997	3	0
1997	4	0
1997	5	0
1997	6	0
1997	7	0
1997	8	1
1997	9	1
1997	10	1
1997	11	1
1997	12	1
1998	1	0
1998	2	0
1998	3	0
1998	4	0
1998	5	0
1998	6	0
1998	7	0
1998	8	0
1998	9	0
1998	10	0
1998	11	0
1998	12	0
1999	1	0
1999	2	0
1999	3	0
1999	4	0
1999	5	0
1999	6	0
1999	7	0
1999	8	0
1999	9	0
1999	10	0
1999	11	0
1999	12	0
2000	1	0
2000	2	0
2000	3	0
2000	4	0
2000	5	0
2000	6	0
2000	7	0
2000	8	0
2000	9	0
2000	10	0
2000	11	0
2000	12	0
2001	1	0
2001	2	0
2001	3	0
2001	4	0
2001	5	0
2001	6	0
2001	7	0
2001	8	0
2001	9	0

SHORT TERM MODELS

BINARY VARIABLES -- CONTINUED

YEAR	MONTH	D97897C
2001	10	0
2001	11	0
2001	12	0
2002	1	0
2002	2	0
2002	3	0
2002	4	0
2002	5	0
2002	6	0
2002	7	0
2002	8	0
2002	9	0
2002	10	0
2002	11	0
2002	12	0
2003	1	0
2003	2	0
2003	3	0
2003	4	0
2003	5	0
2003	6	0
2003	7	0
2003	8	0
2003	9	0
2003	10	0
2003	11	0
2003	12	0
2004	1	0
2004	2	0
2004	3	0
2004	4	0
2004	5	0
2004	6	0
2004	7	0
2004	8	0
2004	9	0
2004	10	0
2004	11	0
2004	12	0

SHORT TERM MODELS 91
OTHER VARIABLES

YEAR	MONTH	E_KPC
1988	1	581.048
1988	2	528.311
1988	3	509.167
1988	4	439.604
1988	5	431.927
1988	6	435.595
1988	7	480.638
1988	8	515.973
1988	9	431.844
1988	10	478.500
1988	11	481.651
1988	12	546.308
1989	1	543.333
1989	2	519.844
1989	3	486.064
1989	4	453.507
1989	5	454.286
1989	6	440.846
1989	7	478.012
1989	8	493.397
1989	9	458.989
1989	10	447.915
1989	11	489.099
1989	12	629.622
1990	1	558.841
1990	2	488.023
1990	3	504.165
1990	4	467.643
1990	5	446.670
1990	6	470.799
1990	7	506.480
1990	8	507.962
1990	9	466.419
1990	10	479.645
1990	11	496.873
1990	12	549.509
1991	1	597.584
1991	2	532.011
1991	3	531.543
1991	4	443.859
1991	5	488.878
1991	6	471.136
1991	7	523.231
1991	8	517.644
1991	9	472.732
1991	10	483.025
1991	11	536.752
1991	12	574.619
1992	1	616.102
1992	2	541.801
1992	3	562.303
1992	4	490.283
1992	5	472.673
1992	6	458.579
1992	7	518.881

SHORT TERM MODELS 92
OTHER VARIABLES

YEAR	MONTH	E_KPC
1992	8	492.013
1992	9	465.844
1992	10	487.016
1992	11	518.969
1992	12	603.761
1993	1	593.808
1993	2	580.194
1993	3	580.538
1993	4	481.740
1993	5	466.828
1993	6	504.770
1993	7	572.864
1993	8	557.184
1993	9	479.428
1993	10	501.304
1993	11	539.664
1993	12	622.936
1994	1	697.921
1994	2	565.484
1994	3	556.229
1994	4	478.960
1994	5	488.394
1994	6	523.097
1994	7	543.788
1994	8	532.578
1994	9	463.592
1994	10	501.028
1994	11	526.690
1994	12	613.411
1995	1	669.477
1995	2	612.765
1995	3	562.555
1995	4	482.724
1995	5	495.456
1995	6	509.891
1995	7	575.596
1995	8	616.349
1995	9	487.009
1995	10	515.918
1995	11	590.011
1995	12	684.036
1996	1	702.159
1996	2	637.801
1996	3	632.063
1996	4	528.543
1996	5	520.862
1996	6	531.687
1996	7	548.966
1996	8	574.147
1996	9	498.443
1996	10	525.868
1996	11	617.291
1996	12	642.291
1997	1	705.679
1997	2	556.955

SHORT TERM MODELS
OTHER VARIABLES

YEAR	MONTH	E_KPC
1997	3	562.397
1997	4	550.612
1997	5	514.559
1997	6	513.901
1997	7	583.191
1997	8	555.925
1997	9	496.498
1997	10	553.483
1997	11	615.828
1997	12	687.825
1998	1	618.515
1998	2	543.975
1998	3	570.205
1998	4	480.085
1998	5	512.062
1998	6	511.821
1998	7	563.589
1998	8	577.643
1998	9	543.716
1998	10	527.940
1998	11	564.416
1998	12	629.994
1999	1	654.726
1999	2	581.538
1999	3	604.010
1999	4	501.045
1999	5	503.268
1999	6	544.755
1999	7	615.201
1999	8	571.440
1999	9	503.655
1999	10	535.390
1999	11	576.988
1999	12	652.809
2000	1	686.357
2000	2	608.629
2000	3	591.717
2000	4	526.796
2000	5	529.235
2000	6	534.976
2000	7	578.641
2000	8	587.942
2000	9	526.693
2000	10	544.218
2000	11	585.859
2000	12	660.788
2001	1	695.025
2001	2	618.216
2001	3	602.002
2001	4	537.527
2001	5	538.717
2001	6	543.917
2001	7	587.563
2001	8	596.723
2001	9	535.698

SHORT TERM MODELS
OTHER VARIABLES

YEAR	MONTH	E_KPC
2001	10	553.321
2001	11	594.425
2001	12	669.338
2002	1	703.731
2002	2	627.303
2002	3	611.330
2002	4	546.819
2002	5	547.881
2002	6	552.916
2002	7	596.484
2002	8	605.803
2002	9	544.812
2002	10	562.321
2002	11	603.404
2002	12	678.253
2003	1	712.698
2003	2	636.408
2003	3	620.496
2003	4	555.953
2003	5	556.977
2003	6	562.028
2003	7	605.636
2003	8	614.998
2003	9	554.024
2003	10	571.517
2003	11	612.558
2003	12	687.425
2004	1	721.921
2004	2	645.432
2004	3	629.757
2004	4	565.210
2004	5	566.211
2004	6	571.258
2004	7	614.883
2004	8	624.253
2004	9	563.270
2004	10	580.752
2004	11	621.787
2004	12	696.652

SHORT TERM MODELS
MODEL ESTIMATION

Autoreg Procedure

Model: EL_KPC
Dependent Variable = EL_KPC   ENERGY LOSSES

Ordinary Least Squares Estimates

SSE	2524.682	DFE	110
MSE	22.95165	Root MSE	4.790788
SBC	832.2603	AIC	780.9238
Reg Rsq	0.7574	Total Rsq	0.7574
Durbin-Watson	0.8611		

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
Intercept	1	35.019077	7.6631	4.570	0.0001
D1	1	-3.634749	2.1171	-1.717	0.0888
D2	1	-6.253620	2.1853	-2.862	0.0050
D3	1	-6.153172	2.3055	-2.669	0.0088
D4	1	-9.924279	2.6016	-3.815	0.0002
D5	1	-13.088208	2.6196	-4.996	0.0001
D6	1	-10.356739	2.5625	-4.042	0.0001
D7	1	-6.324848	2.2927	-2.759	0.0068
D8	1	-7.242171	2.2899	-3.163	0.0020
D9	1	-7.370855	2.7898	-2.642	0.0094
DA	1	-6.310782	2.5970	-2.430	0.0167
DB	1	-4.767979	2.3288	-2.048	0.0429
E_KPC	1	0.014292	0.0125	1.147	0.2537
D928939	1	7.766285	1.4964	5.190	0.0001
D935941	1	15.575279	1.8608	8.374	0.0001
D963	1	20.760808	5.1638	4.020	0.0001
D967973	1	-5.057285	1.7812	-2.839	0.0054
D97897C	1	-18.205672	2.4022	-7.578	0.0001

Variable	DF	Variable Label
Intercept	1	
D1	1	
D2	1	
D3	1	
D4	1	
D5	1	
D6	1	
D7	1	
D8	1	
D9	1	
DA	1	
DB	1	
E_KPC	1	TOTAL ENERGY REQUIREMENTS
D928939	1	BINARY FROM 92:8 TO 93:9
D935941	1	BINARY FROM 93:5 TO 94:1
D963	1	BINARY 96:3
D967973	1	BINARY FROM 96:7 TO 97:3
D97897C	1	BINARY FROM 97:8 TO 97:12

SHORT TERM MODELS
MODEL ESTIMATION

Autoreg Procedure

Estimates of Autocorrelations

```
Lag  Covariance  Correlation -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

  0    19.72408     1.000000 |                    |********************|
  1    11.23185     0.569448 |                    |***********         |
  2    8.957145     0.454122 |                    |*********           |
  3    6.329537     0.320904 |                    |******              |
  4    2.379074     0.120618 |                    |**                  |
  5    0.576528     0.029230 |                    |*                   |
  6    0.313677     0.015903 |                    |                    |
  7    0.043809     0.002221 |                    |                    |
  8    -0.51444    -0.026082 |                   *|                    |
  9    -2.37214    -0.120266 |                  **|                    |
 10    -2.95734    -0.149935 |                 ***|                    |
 11     -3.8149    -0.193414 |                ****|                    |
 12     -7.1516    -0.362582 |             *******|                    |
```

Preliminary MSE = 10.98628

Estimates of the Autoregressive Parameters

Lag	Coefficient	Std Error	t Ratio
1	-0.42258176	0.097584	-4.330
2	-0.24418032	0.106169	-2.300
3	-0.07556271	0.108989	-0.693
4	0.17568222	0.108546	1.619
5	0.10577390	0.109985	0.962
6	-0.07835637	0.110173	-0.711
7	-0.08437525	0.110173	-0.766
8	-0.00676620	0.109985	-0.062
9	0.12309861	0.108546	1.134
10	-0.01267700	0.108989	-0.116
11	-0.08456645	0.106169	-0.797
12	0.25843646	0.097584	2.648

Yule-Walker Estimates

SSE	1260.74	DFE	98
MSE	12.8647	Root MSE	3.586739
SBC	803.4846	AIC	717.9237
Reg Rsq	0.7683	Total Rsq	0.8789
Durbin-Watson	1.9008		

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
Intercept	1	31.185077	6.5657	4.750	0.0001
D1	1	-3.691530	1.1214	-3.292	0.0014
D2	1	-6.384072	1.3454	-4.745	0.0001
D3	1	-6.268926	1.5436	-4.061	0.0001
D4	1	-9.784828	1.9754	-4.953	0.0001
D5	1	-12.289608	2.0145	-6.101	0.0001

SHORT TERM MODELS
MODEL ESTIMATION 97

Autoreg Procedure

Variable	DF	B Value	Std Error	t Ratio	Approx Prob
D6	1	-9.756987	1.9497	-5.004	0.0001
D7	1	-5.803510	1.6867	-3.441	0.0009
D8	1	-7.273117	1.6621	-4.376	0.0001
D9	1	-6.638521	2.0282	-3.273	0.0015
DA	1	-5.529892	1.7349	-3.187	0.0019
DB	1	-4.289937	1.3368	-3.210	0.0018
E_KPC	1	0.021520	0.0107	2.010	0.0472
D928939	1	10.622258	2.0069	5.293	0.0001
D935941	1	8.640807	2.3411	3.691	0.0004
D963	1	20.058758	3.2900	6.097	0.0001
D967973	1	-6.949914	2.2436	-3.098	0.0025
D97897C	1	-16.185933	2.7942	-5.793	0.0001

Variable	DF	Variable Label
Intercept	1	
D1	1	
D2	1	
D3	1	
D4	1	
D5	1	
D6	1	
D7	1	
D8	1	
D9	1	
DA	1	
DB	1	
E_KPC	1	TOTAL ENERGY REQUIREMENTS
D928939	1	BINARY FROM 92:8 TO 93:9
D935941	1	BINARY FROM 93:5 TO 94:1
D963	1	BINARY 96:3
D967973	1	BINARY FROM 96:7 TO 97:3
D97897C	1	BINARY FROM 97:8 TO 97:12

SHORT TERM MODELS
ANNUAL LEVELS AND RATES OF GROWTH 98

YEAR	ENERGY LOSSES	RATE OF GROWTH
1988	416	.
1989	455	9.5
1990	391	-14.1
1991	426	8.9
1992	498	17.1
1993	652	30.8
1994	433	-33.6
1995	413	-4.6
1996	450	9.0
1997	304	-32.5
1998	438	44.2
1999	448	2.4
2000	443	-1.2
2001	451	1.9
2002	450	-0.3
2003	454	1.0
2004	455	0.2

Long-term Residential Customer Model

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
ENDOGENOUS VARIABLES

Variable	Label	Mean
YEAR	YEAR	1997.00
CR_KPC	RESIDENTIAL CUSTOMERS	126.9649638

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
ENDOGENOUS VARIABLES

OBS	YEAR	CR_KPC
1	1975	106.399
2	1976	110.549
3	1977	113.651
4	1978	116.439
5	1979	118.910
6	1980	121.094
7	1981	122.698
8	1982	124.206
9	1983	125.325
10	1984	126.300
11	1985	127.027
12	1986	127.676
13	1987	128.135
14	1988	128.973
15	1989	130.028
16	1990	131.085
17	1991	132.295
18	1992	133.840
19	1993	135.697
20	1994	137.435
21	1995	139.392
22	1996	140.844
23	1997	142.197
24	1998	.
25	1999	.
26	2000	.
27	2001	.
28	2002	.
29	2003	.
30	2004	.
31	2005	.
32	2006	.
33	2007	.
34	2008	.
35	2009	.
36	2010	.
37	2011	.
38	2012	.
39	2013	.
40	2014	.
41	2015	.
42	2016	.
43	2017	.
44	2018	.
45	2019	.

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
EXOGENOUS VARIABLES

Variable	Label	Mean
YEAR	YEAR	1997.00
L_KPC	SERVICE AREA EMPLOYMENT	158654.78
D7576	BINARY VARIABLE, 1975 AND 1976	0.0444444
D77	BINARY VARIABLE, 1977	0.0222222
D96ON	BINARY VARIABLE, 1996 ON	0.5333333

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
EXOGENOUS VARIABLES

OBS	YEAR	L_KPC	D7576	D77	D96ON
1	1975	118616	1	0	0
2	1976	124412	1	0	0
3	1977	129793	0	1	0
4	1978	134357	0	0	0
5	1979	137700	0	0	0
6	1980	139418	0	0	0
7	1981	139324	0	0	0
8	1982	138095	0	0	0
9	1983	136624	0	0	0
10	1984	135805	0	0	0
11	1985	136529	0	0	0
12	1986	139328	0	0	0
13	1987	143280	0	0	0
14	1988	147098	0	0	0
15	1989	149499	0	0	0
16	1990	149197	0	0	0
17	1991	147489	0	0	0
18	1992	150511	0	0	0
19	1993	150747	0	0	0
20	1994	153517	0	0	0
21	1995	154778	0	0	0
22	1996	156504	0	0	1
23	1997	157928	0	0	1
24	1998	159325	0	0	1
25	1999	160711	0	0	1
26	2000	162106	0	0	1
27	2001	163517	0	0	1
28	2002	164953	0	0	1
29	2003	166413	0	0	1
30	2004	167910	0	0	1
31	2005	169440	0	0	1
32	2006	171008	0	0	1
33	2007	172615	0	0	1
34	2008	174261	0	0	1
35	2009	175946	0	0	1
36	2010	177668	0	0	1
37	2011	179428	0	0	1
38	2012	181227	0	0	1
39	2013	183065	0	0	1
40	2014	184944	0	0	1
41	2015	186864	0	0	1
42	2016	188826	0	0	1
43	2017	190831	0	0	1
44	2018	192881	0	0	1
45	2019	194977	0	0	1

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
MODEL ESTIMATION

SYSLIN Procedure
Ordinary Least Squares Estimation

Model: CR_KPC
Dependent variable: CR_KPC RESIDENTIAL CUSTOMERS

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Prob>F
Model	5	1977.84369	395.56874	1749.232	0.0001
Error	17	3.84435	0.22614		
C Total	22	1981.68805			

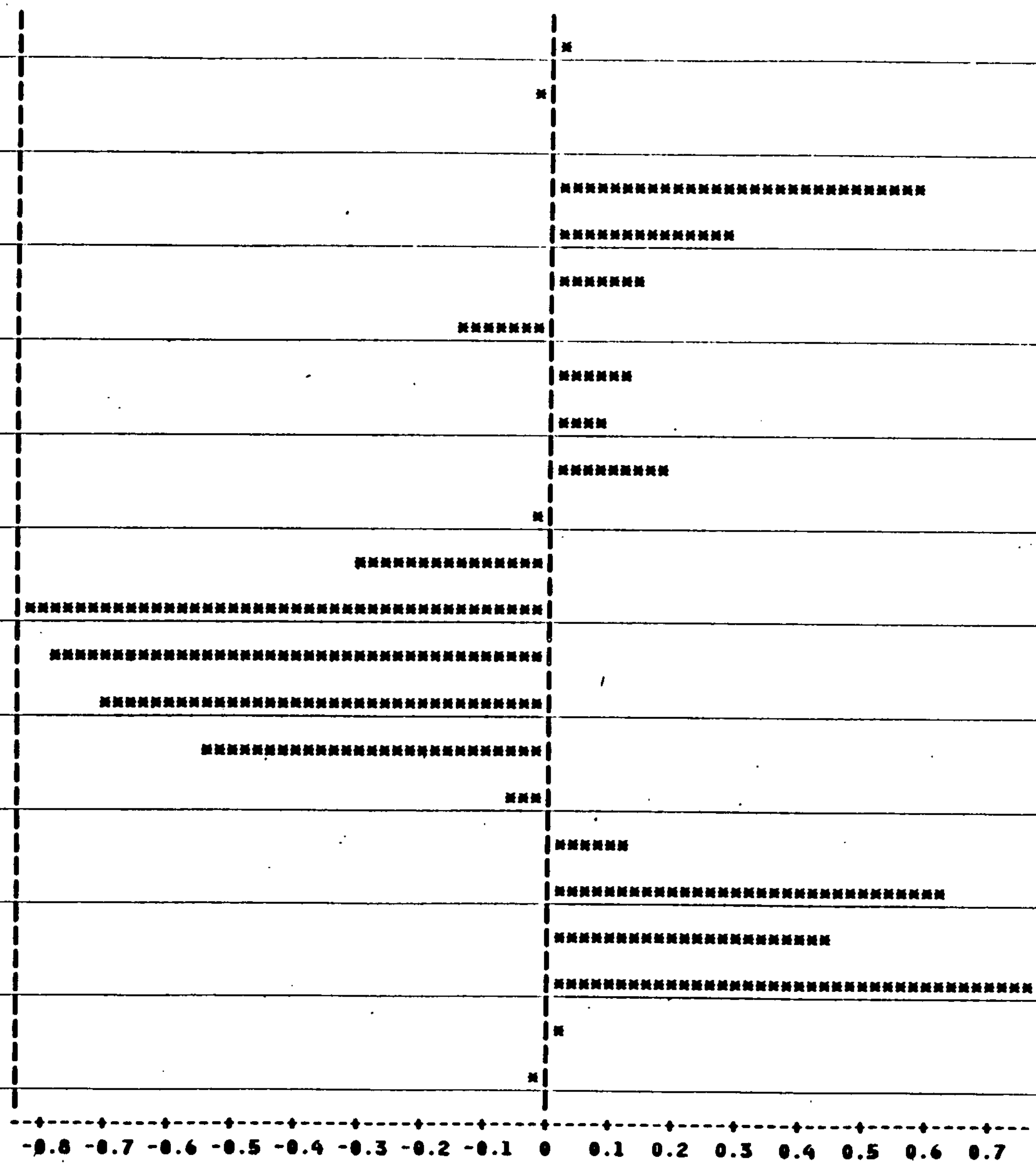
Root MSE	0.47554	R-Square	0.9981
Dep Mean	126.96496	Adj R-SQ	0.9975
C.V.	0.37454		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	T for H0: Parameter=0	Prob > |T|	Variable Label
INTERCEP	1	3.175711	2.439539	1.302	0.2104	Intercept
CR_KPC1	1	0.865259	0.035389	24.450	0.0001	RESIDENTIAL CUSTOMERS, LAG 1-YEAR
L_KPC	1	0.000107	0.000033594	3.179	0.0055	SERVICE AREA EMPLOYMENT
D7576	1	2.039122	0.534850	3.813	0.0014	BINARY VARIABLE, 1975 AND 1976
D77	1	0.960069	0.567508	1.692	0.1089	BINARY VARIABLE, 1977
D96ON	1	0.315670	0.429728	0.735	0.4726	BINARY VARIABLE, 1996 ON

Durbin-Watson	0.573
(For Number of Obs.)	23
1st Order Autocorrelation	0.713

KENTUCKY POWER CO..ANY
RESIDENTIAL CUSTOMERS
MODEL RESIDUALS



YEAR	Residual Values Sum
1975	0.016218
1976	-0.016218
1977	0.000000
1978	0.575631
1979	0.278404
1980	0.139934
1981	-0.135069
1982	0.116098
1983	0.087392
1984	0.182138
1985	-0.012412
1986	-0.291838
1987	-0.815455
1988	-0.782807
1989	-0.709072
1990	-0.532883
1991	-0.055545
1992	0.120173
1993	0.615643
1994	0.449837
1995	0.769824
1996	0.027451
1997	-0.027451

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
MODEL SIMULATION

SIMLIN Procedure

Inverse Coefficient Matrix for Endogenous Variables

	CR_KPC
CR_KPC	1.0000

Reduced Form for Lagged Endogenous Variables

	CR_KPC1
CR_KPC	0.8653

Reduced Form for Exogenous Variables

	L_KPC	D7576	D77	D960N	INTERCEP
CR_KPC	0.000107	2.0391	0.9601	0.3157	3.1757

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
MODEL SIMULATION

SIMLIN Procedure

Statistics of Fit

Variable	N	Mean Error	Mean % Error	Mean Abs Error	Mean Abs % Error	RMS Error	RMS % Error	Label
CR_KPC	23	-0.1312	-0.0905	0.7558	0.58429	0.9566	0.7355	RESIDENTIAL CUSTOMERS

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
ACTUAL AND FORECAST

YEAR	RESIDENTIAL CUSTOMERS	GROWTH RATE
1975	106.399	.
1976	110.549	3.9
1977	113.651	2.8
1978	116.439	2.5
1979	118.910	2.1
1980	121.094	1.8
1981	122.698	1.3
1982	124.206	1.2
1983	125.325	0.9
1984	126.300	0.8
1985	127.027	0.6
1986	127.676	0.5
1987	128.135	0.4
1988	128.973	0.7
1989	130.028	0.8
1990	131.085	0.8
1991	132.295	0.9
1992	133.840	1.2
1993	135.697	1.4
1994	137.435	1.3
1995	139.392	1.4
1996	140.844	1.0
1997	142.197	1.0
1998	143.138	0.7
1999	144.507	1.0
2000	145.840	0.9
2001	147.145	0.9
2002	148.427	0.9
2003	149.692	0.9
2004	150.947	0.8
2005	152.195	0.8
2006	153.444	0.8
2007	154.695	0.8
2008	155.954	0.8
2009	157.223	0.8
2010	158.505	0.8
2011	159.802	0.8
2012	161.117	0.8
2013	162.451	0.8
2014	163.805	0.8
2015	165.183	0.8
2016	166.584	0.8
2017	168.010	0.9
2018	169.464	0.9
2019	170.945	0.9

Long-term Residential KWh Usage Model

KENTUCKY POWER CO.. ANY
RESIDENTIAL USAGE/ENERGY SALES
ENDOGENOUS VARIABLES

Variable	Label	Mean
YEAR	YEAR	1997.00
ER_KPC	ENERGY SALES, RESIDENTIAL	1664.48
USE	RES. ELEC. ENERGY USAGE PER CUSTOMER	12.9929148

KENTUCKY POWER COMPANY
RESIDENTIAL USAGE/ENERGY SALES
EXOGENOUS VARIABLES

OBS	YEAR	L_KPC	HDD_HUNT	CDD_HUNT	D80	D960N	GPRNDX	PRNDX
1	1975	118616	4249	1274	0	0	0.57	1.54
2	1976	124412	4736	867	0	0	0.58	1.43
3	1977	129793	4754	1373	0	0	0.73	1.57
4	1978	134357	5150	1308	0	0	0.74	1.53
5	1979	137700	4753	1004	0	0	0.80	1.52
6	1980	139418	5021	1310	1	0	0.91	1.40
7	1981	139324	4847	1138	0	0	0.95	1.40
8	1982	138095	4502	822	0	0	1.15	1.44
9	1983	136624	4683	1374	0	0	1.32	1.49
10	1984	135805	4452	1193	0	0	1.24	1.47
11	1985	136529	4502	1047	0	0	1.22	1.64
12	1986	139328	4258	1360	0	0	1.11	1.64
13	1987	143280	4409	1366	0	0	0.99	1.49
14	1988	147098	4854	1217	0	0	0.94	1.38
15	1989	149499	4829	1080	0	0	0.94	1.37
16	1990	149197	3627	1165	0	0	0.94	1.35
17	1991	147489	3975	1670	0	0	0.89	1.26
18	1992	150511	4401	942	0	0	0.89	1.21
19	1993	150747	4587	1294	0	0	0.90	1.14
20	1994	153517	4362	1100	0	0	0.91	1.12
21	1995	154778	4733	1264	0	0	0.82	1.07
22	1996	156504	4878	1087	0	1	0.88	1.03
23	1997	157928	4707	839	0	1	1.00	1.00
24	1998	159325	4665	1005	0	1	0.92	0.99
25	1999	160711	4665	1005	0	1	0.93	0.96
26	2000	162106	4665	1005	0	1	0.93	0.94
27	2001	163517	4665	1005	0	1	0.93	0.91
28	2002	164953	4665	1005	0	1	0.94	0.88
29	2003	166413	4665	1005	0	1	0.94	0.85
30	2004	167910	4665	1005	0	1	0.94	0.85
31	2005	169440	4665	1005	0	1	0.95	0.85
32	2006	171008	4665	1005	0	1	0.95	0.85
33	2007	172615	4665	1005	0	1	0.95	0.85
34	2008	174261	4665	1005	0	1	0.96	0.85
35	2009	175946	4665	1005	0	1	0.96	0.85
36	2010	177668	4665	1005	0	1	0.96	0.85
37	2011	179428	4665	1005	0	1	0.96	0.86
38	2012	181227	4665	1005	0	1	0.97	0.86
39	2013	183065	4665	1005	0	1	0.97	0.86
40	2014	184944	4665	1005	0	1	0.97	0.85
41	2015	186864	4665	1005	0	1	0.98	0.85
42	2016	188826	4665	1005	0	1	0.98	0.85
43	2017	190831	4665	1005	0	1	0.98	0.85
44	2018	192881	4665	1005	0	1	0.98	0.85
45	2019	194977	4665	1005	0	1	0.98	0.85

KENTUCKY POWER CO.. ANY
RESIDENTIAL USAGE/ENERGY SALES
MODEL ESTIMATION

SYSLIN Procedure
Ordinary Least Squares Estimation

Model: USE
Dependent variable: USE RES. ELEC. ENERGY USAGE PER CUSTOMER

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Prob>F
Model	6	59.37179	9.89530	71.051	0.0001
Error	16	2.22834	0.13927		
C Total	22	61.60012			

Root MSE	0.37319	R-Square	0.9638
Dep Mean	12.99291	Adj R-SQ	0.9503
C.V.	2.87226		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	T for H0: Parameter=0	Prob > |T|	Variable Label
INTERCEP	1	-232.593440	24.350614	-9.552	0.0001	Intercept
LPRGPRS	1	-0.975120	0.477870	-2.041	0.0582	RES. ELEC./RES. GAS PRICE RATIO, LOG
LL	1	18.554920	1.897227	9.780	0.0001	SERVICE AREA EMPLOYMENT, LOG
D80	1	-0.669746	0.408996	-1.638	0.1210	BINARY VARIABLE, 1980
D96ON	1	0.470275	0.336423	1.398	0.1812	BINARY VARIABLE, 1996 ON
LHDD	1	2.067917	1.146303	1.804	0.0901	HUNTINGTON, WV HEATING DEGREE DAYS, LOG
LCDD	1	1.165201	0.488290	2.386	0.0297	HUNTINGTON, WV COOLING DEGREE DAYS, LOG

Durbin-Watson	1.191
(For Number of Obs.)	23
1st Order Autocorrelation	0.402

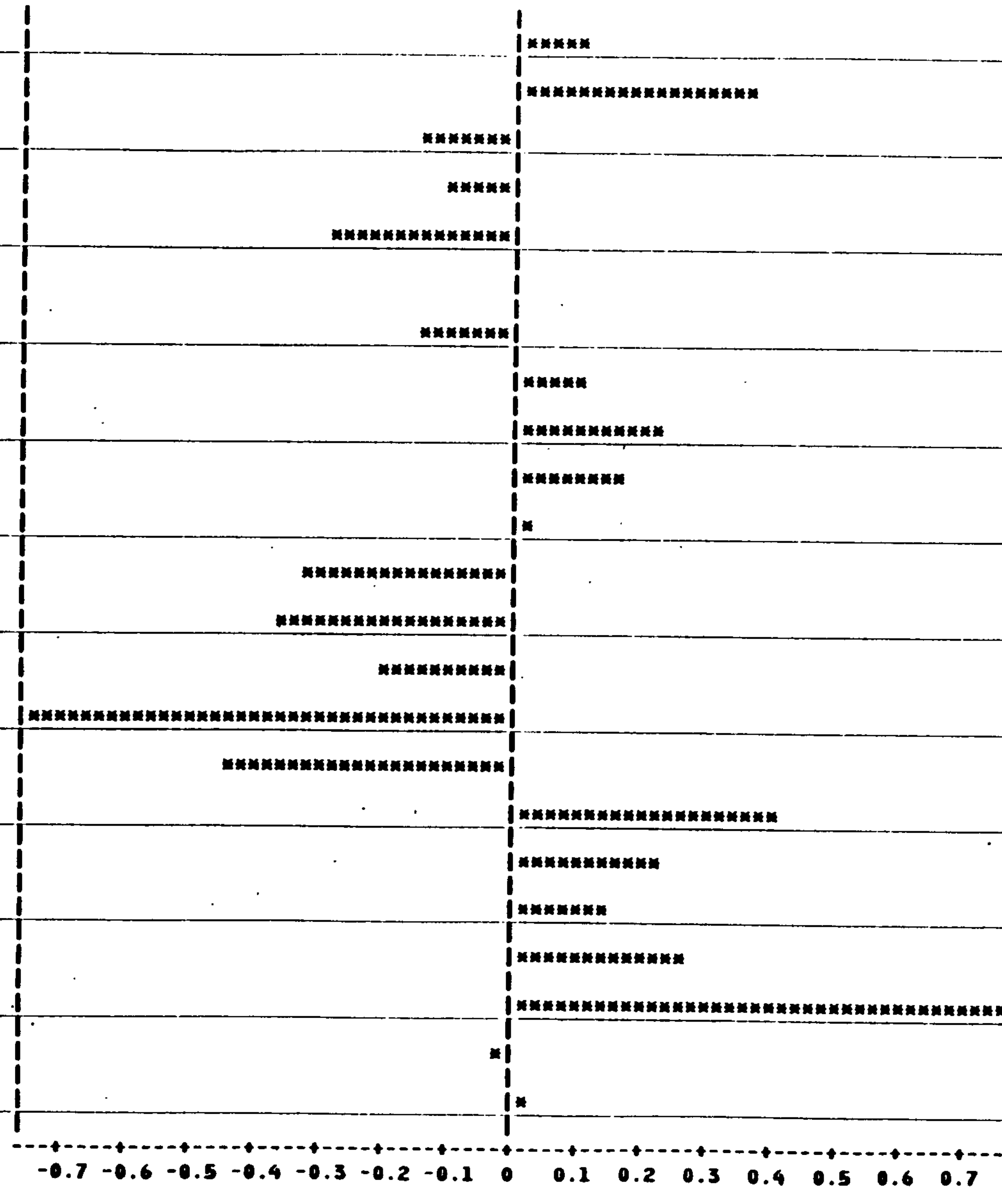
KENTUCKY POWER COMPANY
RESIDENTIAL USAGE/ENERGY SALES
ENDOGENOUS VARIABLES

OBS	YEAR	ER_KPC	USE
1	1975	972.23	9.1376
2	1976	1117.90	10.1123
3	1977	1250.72	11.0049
4	1978	1379.11	11.8441
5	1979	1398.69	11.7626
6	1980	1468.72	12.1288
7	1981	1534.82	12.5089
8	1982	1511.41	12.1686
9	1983	1613.65	12.8757
10	1984	1581.79	12.5241
11	1985	1573.25	12.3852
12	1986	1609.45	12.6058
13	1987	1681.27	13.1211
14	1988	1777.39	13.7811
15	1989	1735.86	13.3499
16	1990	1717.96	13.1057
17	1991	1897.05	14.3396
18	1992	1886.02	14.0917
19	1993	1971.56	14.5291
20	1994	2024.84	14.7331
21	1995	2191.98	15.7253
22	1996	2190.62	15.5535
23	1997	2196.75	15.4486
24	1998	.	.
25	1999	.	.
26	2000	.	.
27	2001	.	.
28	2002	.	.
29	2003	.	.
30	2004	.	.
31	2005	.	.
32	2006	.	.
33	2007	.	.
34	2008	.	.
35	2009	.	.
36	2010	.	.
37	2011	.	.
38	2012	.	.
39	2013	.	.
40	2014	.	.
41	2015	.	.
42	2016	.	.
43	2017	.	.
44	2018	.	.
45	2019	.	.

KENTUCKY POWER COMPANY
RESIDENTIAL USAGE/ENERGY SALES
EXOGENOUS VARIABLES

Variable	Label	Mean
YEAR	YEAR	1997.00
L_KPC	SERVICE AREA EMPLOYMENT	158654.78
HDD_HUNT	HUNTINGTON, WV HEATING DEGREE DAYS	4619.98
CDD_HUNT	HUNTINGTON, WV COOLING DEGREE DAYS	1093.42
D80	BINARY VARIABLE, 1980	0.0222222
D96ON	BINARY VARIABLE, 1996 ON	0.5333333
GPRNDX	REAL KY RES. GAS PRICE INDEX, 1997=1.00	0.9433333
PRNDX	REAL RES. ELEC. PRICE INDEX, 1997=1.00	1.1255556

KENTUCKY POWER CO... ANY
RESIDENTIAL USAGE/ENERGY SALES
MODEL RESIDUALS



YEAR	Residual Values Sum
1975	0.102488
1976	0.368364
1977	-0.139528
1978	-0.109720
1979	-0.270104
1980	0.000000
1981	-0.137385
1982	0.108115
1983	0.210618
1984	0.153019
1985	0.024468
1986	-0.317150
1987	-0.366807
1988	-0.207360
1989	-0.746234
1990	-0.433411
1991	0.398387
1992	0.212782
1993	0.137075
1994	0.261350
1995	0.751033
1996	-0.019644
1997	0.019644

KENTUCKY POWER COMPANY
RESIDENTIAL USAGE/ENERGY SALES
ACTUAL AND FORECAST

YEAR	RESIDENTIAL USAGE	RESIDENTIAL ENERGY SALES	GRRR
1975	9.1376	972.23	.
1976	10.1123	1117.90	15.0
1977	11.0049	1250.72	11.9
1978	11.8441	1379.11	10.3
1979	11.7626	1398.69	1.4
1980	12.1288	1468.72	5.0
1981	12.5089	1534.82	4.5
1982	12.1686	1511.41	-1.5
1983	12.8757	1613.65	6.8
1984	12.5241	1581.79	-2.0
1985	12.3852	1573.25	-0.5
1986	12.6058	1609.45	2.3
1987	13.1211	1681.27	4.5
1988	13.7811	1777.39	5.7
1989	13.3499	1735.86	-2.3
1990	13.1057	1717.96	-1.0
1991	14.3396	1897.05	10.4
1992	14.0917	1886.02	-0.6
1993	14.5291	1971.56	4.5
1994	14.7331	2024.84	2.7
1995	15.7253	2191.98	8.3
1996	15:5535	2190.62	-0.1
1997	15.4486	2196.75	0.3
1998	15.8169	2264.00	3.1
1999	16.0101	2313.57	2.2
2000	16.2198	2365.50	2.2
2001	16.4174	2415.73	2.1
2002	16.5914	2462.61	1.9
2003	16.7868	2512.85	2.0
2004	16.9794	2562.97	2.0
2005	17.1697	2613.15	2.0
2006	17.3561	2663.18	1.9
2007	17.5384	2713.11	1.9
2008	17.7177	2763.14	1.8
2009	17.8993	2814.18	1.8
2010	18.0825	2866.17	1.8
2011	18.2679	2919.25	1.9
2012	18.4559	2973.55	1.9
2013	18.6460	3029.06	1.9
2014	18.8385	3085.85	1.9
2015	19.0333	3143.96	1.9
2016	19.2303	3203.45	1.9
2017	19.4285	3264.20	1.9
2018	19.6296	3326.50	1.9
2019	19.8324	3390.25	1.9

KENTUCKY POWER COMPANY
COMMERCIAL ENERGY SALES
ENDOGENOUS VARIABLES

Variable	Label	Mean
YEAR	YEAR	1997.00
EC_KPC	ENERGY SALES, COMMERCIAL	805.4116175

KENTUCKY POWER COMPANY
COMMERCIAL ENERGY SALES
ENDOGENOUS VARIABLES

OBS	YEAR	EC_KPC
1	1975	420.20
2	1976	461.77
3	1977	513.49
4	1978	554.89
5	1979	581.37
6	1980	630.95
7	1981	669.18
8	1982	685.52
9	1983	700.15
10	1984	714.59
11	1985	761.99
12	1986	786.15
13	1987	831.77
14	1988	869.40
15	1989	885.68
16	1990	919.62
17	1991	988.98
18	1992	991.36
19	1993	1034.39
20	1994	1072.37
21	1995	1134.51
22	1996	1150.45
23	1997	1165.68
24	1998	.
25	1999	.
26	2000	.
27	2001	.
28	2002	.
29	2003	.
30	2004	.
31	2005	.
32	2006	.
33	2007	.
34	2008	.
35	2009	.
36	2010	.
37	2011	.
38	2012	.
39	2013	.
40	2014	.
41	2015	.
42	2016	.
43	2017	.
44	2018	.
45	2019	.

KENTUCKY POWER COMPANY
COMMERCIAL ENERGY SALES
EXOGENOUS VARIABLE

Variable	Label	Mean
YEAR	YEAR	1997.00
CDD_HUNT	HUNTINGTON, WV COOLING DEGREE DAYS	1093.42
YP	SERVICE AREA PERSONAL INCOME PER CAPITA	0.0149311
D91	BINARY VARIABLE, 1991	0.0222222
D75	BINARY VARIABLE, 1975	0.0222222
D97ON	BINARY VARIABLE, 1997 ON	0.5111111
LCOM	SERVICE AREA COMMERCIAL EMPLOYMENT	99640.76
PCNDX	REAL COM. ELEC. PRICE INDEX, 1997=1.00	1.1468889
GPCNDX	REAL KY COM. GAS PRICE INDEX, 1997=1.00	1.0517778

KENTUCKY POWER COMPANY
COMMERCIAL ENERGY SALES
EXOGENOUS VARIABLE

OBS	YEAR	CDD_HUNT	YP	D91	D75	D97ON	LCOM	PCNDX	GPCNDX
1	1975	1274	0.011301	0	1	0	62210	1.53	1.83
2	1976	867	0.011859	0	0	0	65191	1.45	1.78
3	1977	1373	0.012344	0	0	0	68093	1.64	1.31
4	1978	1308	0.012734	0	0	0	70695	1.63	1.29
5	1979	1004	0.013008	0	0	0	72779	1.65	1.19
6	1980	1310	0.013148	0	0	0	74121	1.50	1.02
7	1981	1138	0.013149	0	0	0	74619	1.49	0.97
8	1982	822	0.013057	0	0	0	74652	1.53	0.79
9	1983	1374	0.012932	0	0	0	74712	1.58	0.69
10	1984	1193	0.012833	0	0	0	75289	1.56	0.74
11	1985	1047	0.012819	0	0	0	76885	1.67	0.76
12	1986	1360	0.012934	0	0	0	79766	1.67	0.84
13	1987	1366	0.013131	0	0	0	83316	1.52	0.96
14	1988	1217	0.013333	0	0	0	86692	1.43	1.01
15	1989	1080	0.013458	0	0	0	89044	1.41	1.03
16	1990	1165	0.013418	0	0	0	89532	1.37	1.04
17	1991	1670	0.013338	1	0	0	89168	1.27	1.11
18	1992	942	0.013652	0	0	0	92486	1.23	1.13
19	1993	1294	0.013570	0	0	0	94119	1.15	1.08
20	1994	1100	0.013792	0	0	0	97165	1.12	1.07
21	1995	1264	0.014065	0	0	0	98870	1.08	1.19
22	1996	1087	0.014409	0	0	0	100993	1.03	1.11
23	1997	839	0.014574	0	0	1	102209	1.00	1.08
24	1998	1005	0.014744	0	0	1	103426	0.98	1.06
25	1999	1005	0.014916	0	0	1	104633	0.96	1.06
26	2000	1005	0.015092	0	0	1	105854	0.93	1.05
27	2001	1005	0.015269	0	0	1	107096	0.90	1.05
28	2002	1005	0.015451	0	0	1	108359	0.88	1.04
29	2003	1005	0.015634	0	0	1	109643	0.85	1.04
30	2004	1005	0.015823	0	0	1	110953	0.85	1.03
31	2005	1005	0.016016	0	0	1	112292	0.85	1.03
32	2006	1005	0.016211	0	0	1	113660	0.85	1.02
33	2007	1005	0.016409	0	0	1	115056	0.85	1.02
34	2008	1005	0.016609	0	0	1	116482	0.85	1.02
35	2009	1005	0.016812	0	0	1	117935	0.85	1.01
36	2010	1005	0.017018	0	0	1	119419	0.85	1.01
37	2011	1005	0.017227	0	0	1	120931	0.85	1.01
38	2012	1005	0.017439	0	0	1	122471	0.85	1.00
39	2013	1005	0.017655	0	0	1	124044	0.85	1.00
40	2014	1005	0.017875	0	0	1	125645	0.85	1.00
41	2015	1005	0.018100	0	0	1	127276	0.85	0.99
42	2016	1005	0.018329	0	0	1	128940	0.85	0.99
43	2017	1005	0.018563	0	0	1	130633	0.85	0.99
44	2018	1005	0.018803	0	0	1	132360	0.85	0.99
45	2019	1005	0.019048	0	0	1	134120	0.85	0.98

KENTUCKY POWER COMPANY
COMMERCIAL ENERGY SALES
MODEL ESTIMATION

SYSLIN Procedure
Ordinary Least Squares Estimation

Model: LEC
Dependent variable: LEC ENERGY SALES, COMMERCIAL, LOG

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Prob>F
Model	8	1.94046	0.24256	779.504	0.0001
Error	14	0.00436	0.00031		
C Total	22	1.94481			

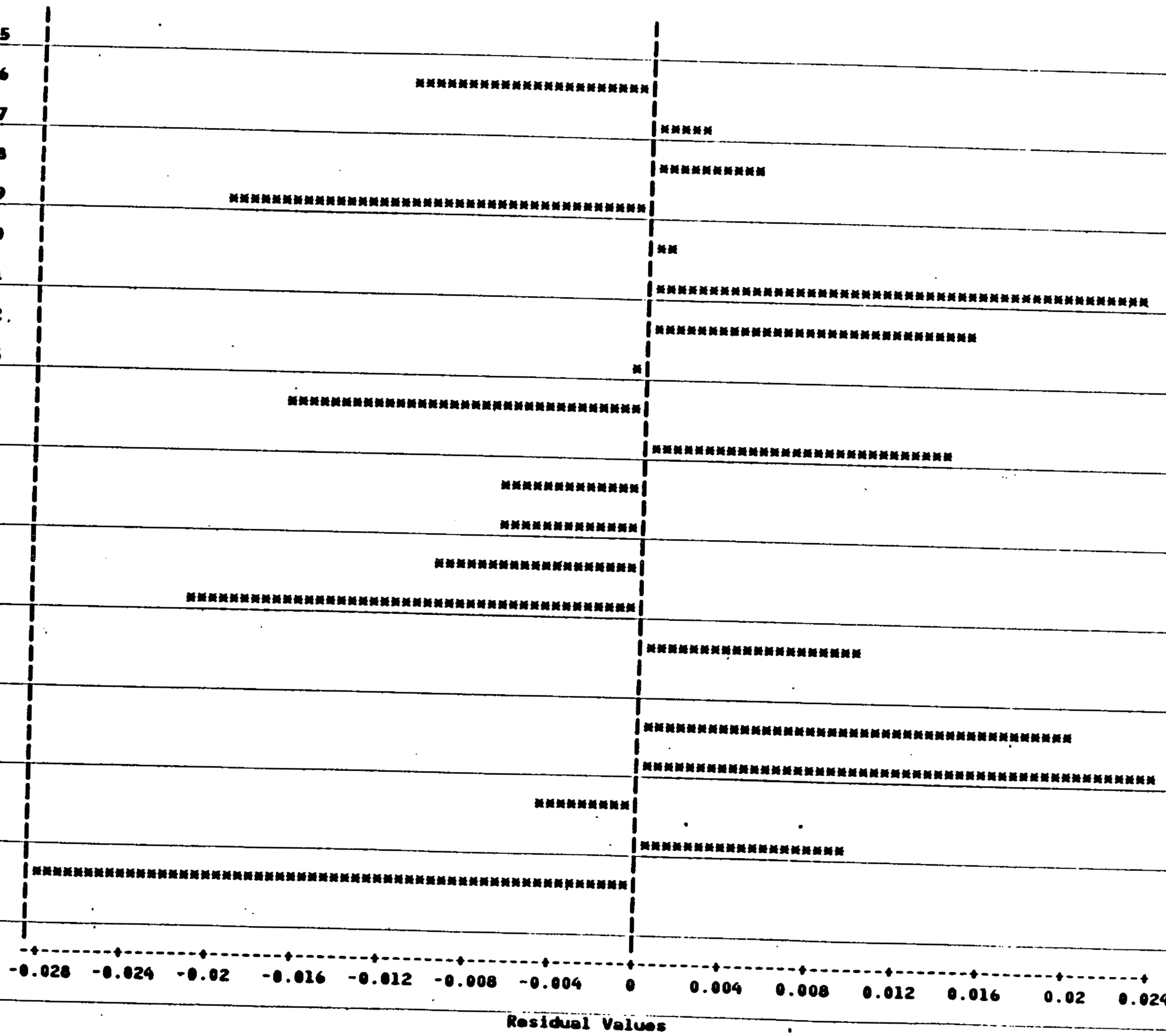
Root MSE	0.01764	R-Square	0.9978
Dep Mean	6.65088	Adj R-SQ	0.9965
C.V.	0.26523		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	T for H0: Parameter=0	Prob > |T|	Variable Label
INTERCEP	1	-8.179573	2.096142	-3.902	0.0016	Intercept
LPC5	1	-0.416526	0.083956	-4.961	0.0002	COM. ELEC. PRICE, 5-YEAR MOVING AVE., LO
LGPC5	1	0.262341	0.023891	10.981	0.0001	COM. GAS PRICE, 5-YEAR MOVING AVE., LOG
LLCOM	1	1.413576	0.105139	13.445	0.0001	SERVICE AREA COMMERCIAL EMPLOYMENT, LOG
LCDD	1	0.003193	0.026929	0.119	0.9073	HUNTINGTON, WV COOLING DEGREE DAYS, LOG
D91	1	0.080840	0.021220	3.810	0.0019	BINARY VARIABLE, 1991
LYP	1	0.197692	0.246487	0.802	0.4359	SERVICE AREA PERSONAL INCOME PER CAPITA,
D75	1	-0.013339	0.028226	-0.473	0.6438	BINARY VARIABLE, 1975
D97ON	1	-0.057554	0.024068	-2.391	0.0314	BINARY VARIABLE, 1997 ON

Durbin-Watson	1.975
(For Number of Obs.)	23
1st Order Autocorrelation	0.013

KENTUCKY POWER CO... ANY
COMMERCIAL ENERGY SALES
MODEL RESIDUALS



YEAR	Residual Values
1975	0.000000
1976	-0.010879
1977	0.002492
1978	0.005167
1979	-0.019725
1980	0.000893
1981	0.022969
1982	0.015035
1983	-0.000395
1984	-0.016542
1985	0.014005
1986	-0.006417
1987	-0.006254
1988	-0.009680
1989	-0.021170
1990	0.009879
1991	0.000000
1992	0.019875
1993	0.023791
1994	-0.004537
1995	0.009708
1996	-0.028214
Sum	0.000000

KENTUCKY POWER COMPANY
COMMERCIAL ENERGY SALES
ACTUAL AND FORECAST

YEAR	COMMERCIAL ENERGY SALES	GROWTH RATE
1975	420.20	.
1976	461.77	9.9
1977	513.49	11.2
1978	554.89	8.1
1979	581.37	4.8
1980	630.95	8.5
1981	669.18	6.1
1982	685.52	2.4
1983	700.15	2.1
1984	714.59	2.1
1985	761.99	6.6
1986	786.15	3.2
1987	831.77	5.8
1988	869.40	4.5
1989	885.68	1.9
1990	919.62	3.8
1991	988.98	7.5
1992	991.36	0.2
1993	1034.39	4.3
1994	1072.37	3.7
1995	1134.51	5.8
1996	1150.45	1.4
1997	1165.68	1.3
1998	1205.44	3.4
1999	1245.47	3.3
2000	1292.92	3.8
2001	1336.12	3.3
2002	1373.59	2.8
2003	1418.63	3.3
2004	1462.33	3.1
2005	1504.17	2.9
2006	1543.47	2.6
2007	1579.38	2.3
2008	1612.48	2.1
2009	1646.42	2.1
2010	1681.30	2.1
2011	1716.81	2.1
2012	1753.75	2.2
2013	1791.79	2.2
2014	1830.65	2.2
2015	1870.66	2.2
2016	1911.91	2.2
2017	1954.07	2.2
2018	1997.46	2.2
2019	2042.07	2.2

Long-term Manufacturing Energy Models

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
ENDOGENOUS VARIABLES

Variable	Label	Mean
YEAR	YEAR	1997.00
EIX_KPC	ENERGY SALES, INDUSTRIAL EXCL MINEPOWER	1614.31

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
ENDOGENOUS VARIABLES

OBS	YEAR	EIX_KPC
1	1975	1040.93
2	1976	1119.07
3	1977	1279.13
4	1978	1396.68
5	1979	1513.01
6	1980	1464.11
7	1981	1489.94
8	1982	1376.41
9	1983	1554.17
10	1984	1637.45
11	1985	1550.69
12	1986	1549.80
13	1987	1741.30
14	1988	1855.81
15	1989	1795.64
16	1990	1841.25
17	1991	1781.62
18	1992	1761.72
19	1993	1701.71
20	1994	1763.53
21	1995	1906.32
22	1996	1978.19
23	1997	2030.64
24	1998	.
25	1999	.
26	2000	.
27	2001	.
28	2002	.
29	2003	.
30	2004	.
31	2005	.
32	2006	.
33	2007	.
34	2008	.
35	2009	.
36	2010	.
37	2011	.
38	2012	.
39	2013	.
40	2014	.
41	2015	.
42	2016	.
43	2017	.
44	2018	.
45	2019	.

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
EXOGENOUS VARIABLES

Variable	Label	Mean
YEAR	YEAR	1997.00
LM_KPC	SERVICE AREA MANUFACTURING EMPLOYMENT	12904.47
FRBM	FRB IND. PROD. INDEX-MANUFACTURING	131.7721389
D95ON	BINARY VARIABLE-1995 ON	0.5555556
D87ON	BINARY VARIABLE-1987 ON	0.7333333
PIXNDX	REAL MAN. ELEC. PRICE INDEX, 1997=1.00	1.0920000
GPINDX	REAL KY MAN. GAS PRICE INDEX, 1997=1.00	0.9202222

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
EXOGENOUS VARIABLES

OBS	YEAR	LM_KPC	FRBM	D95ON	D87ON	PIXNDX	GPINDX
1	1975	13975	59.402	0	0	1.29	0.37
2	1976	14522	65.431	0	0	1.17	0.52
3	1977	14986	71.233	0	0	1.38	0.63
4	1978	15311	75.812	0	0	1.36	0.66
5	1979	15442	78.522	0	0	1.34	0.74
6	1980	15325	75.492	0	0	1.22	0.87
7	1981	14933	76.691	0	0	1.30	0.95
8	1982	14358	72.147	0	0	1.42	1.20
9	1983	13719	76.252	0	0	1.45	1.32
10	1984	13139	83.806	0	0	1.44	1.24
11	1985	12735	85.738	0	0	1.63	1.24
12	1986	12593	88.120	0	0	1.69	1.15
13	1987	12652	92.800	0	1	1.49	0.96
14	1988	12817	97.100	0	1	1.35	0.94
15	1989	12991	99.800	0	1	1.29	0.96
16	1990	13078	98.500	0	1	1.26	0.91
17	1991	13103	96.175	0	1	1.28	0.81
18	1992	13024	99.975	0	1	1.26	0.81
19	1993	11824	103.800	0	1	1.14	0.90
20	1994	11615	110.025	0	1	1.13	0.88
21	1995	12145	115.950	1	1	1.06	0.76
22	1996	12101	120.150	1	1	1.03	0.89
23	1997	12118	126.900	1	1	1.00	1.00
24	1998	12135	131.550	1	1	0.99	0.91
25	1999	12156	133.625	1	1	0.96	0.92
26	2000	12176	137.550	1	1	0.94	0.92
27	2001	12199	141.150	1	1	0.91	0.92
28	2002	12220	145.000	1	1	0.88	0.93
29	2003	12243	149.150	1	1	0.85	0.93
30	2004	12267	153.550	1	1	0.85	0.93
31	2005	12289	157.950	1	1	0.85	0.94
32	2006	12312	162.325	1	1	0.85	0.94
33	2007	12337	166.650	1	1	0.85	0.94
34	2008	12362	170.975	1	1	0.85	0.94
35	2009	12388	175.350	1	1	0.85	0.94
36	2010	12413	179.775	1	1	0.85	0.94
37	2011	12437	184.500	1	1	0.86	0.95
38	2012	12460	189.375	1	1	0.86	0.95
39	2013	12483	194.625	1	1	0.86	0.95
40	2014	12503	200.125	1	1	0.85	0.95
41	2015	12524	205.700	1	1	0.85	0.96
42	2016	12544	211.375	1	1	0.85	0.96
43	2017	12563	217.350	1	1	0.85	0.96
44	2018	12583	223.375	1	1	0.85	0.96
45	2019	12601	229.700	1	1	0.85	0.96

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
MODEL ESTIMATION

SYSLIN Procedure
Ordinary Least Squares Estimation

Model: EIX_KPC
Dependent variable: EIX_KPC ENERGY SALES, INDUSTRIAL EXCL MINEPOWER

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Prob>F
Model	5	1443097.6557	288619.53115	131.370	0.0001
Error	17	37349.06021	2197.00354		
C Total	22	1480446.7159			

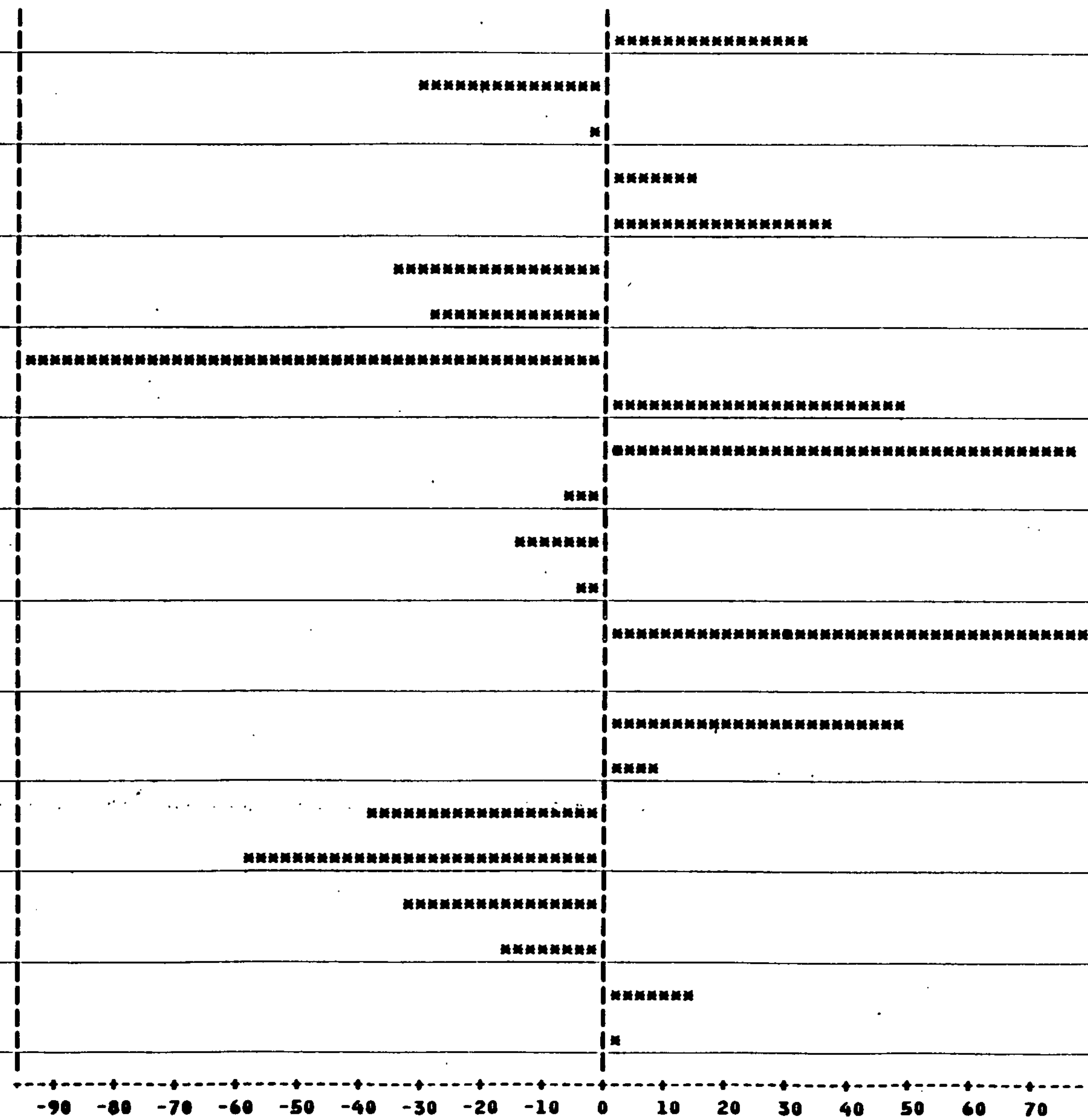
Root MSE	46.87220	R-Square	0.9748
Dep Mean	1614.30996	Adj R-SQ	0.9674
C.V.	2.90354		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	T for H0: Parameter=0	Prob > |T|	Variable Label
INTERCEP	1	-2567.743979	874.300641	-2.937	0.0092	Intercept
PIXGPI5	1	-294.807572	53.285030	-5.533	0.0001	MANUF. ELEC./IND. GAS PRICE RATIO
LFRBM	1	794.690182	181.895940	4.369	0.0004	FRB IND. PROD.. INDEX-MANUF., LOG
LM_KPC	1	0.062895	0.014983	4.198	0.0006	SERVICE AREA MANUFACTURING EMPLOYMENT
D870N	1	146.213061	46.404060	3.151	0.0058	BINARY VARIABLE-1987 ON
D950N	1	52.446789	45.855575	1.144	0.2686	BINARY VARIABLE-1995 ON

Durbin-Watson	1.713
(For Number of Obs.)	23
1st Order Autocorrelation	0.130

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
MODEL RESIDUALS



YEAR	Residual Values Sum
1975	31.8657
1976	-30.2633
1977	-1.1265
1978	14.4302
1979	36.7001
1980	-34.4596
1981	-27.7238
1982	-94.0284
1983	48.6466
1984	75.5338
1985	-5.1263
1986	-14.4484
1987	-3.1028
1988	77.7834
1989	-0.9249
1990	47.1844
1991	7.6665
1992	-37.9938
1993	-58.6689
1994	-31.9438
1995	-16.8409
1996	14.7369
1997	2.1040

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
ACTUAL AND FORECAST

YEAR	ENERGY SALES	GROWTH RATE
1975	1040.93	.
1976	1119.07	7.5
1977	1279.13	14.3
1978	1396.68	9.2
1979	1513.01	8.3
1980	1464.11	-3.2
1981	1489.94	1.8
1982	1376.41	-7.6
1983	1554.17	12.9
1984	1637.45	5.4
1985	1550.69	-5.3
1986	1549.80	-0.1
1987	1741.30	12.4
1988	1855.81	6.6
1989	1795.64	-3.2
1990	1841.25	2.5
1991	1781.62	-3.2
1992	1761.72	-1.1
1993	1701.71	-3.4
1994	1763.53	3.6
1995	1906.32	8.1
1996	1978.19	3.8
1997	2030.64	2.7
1998	2064.74	1.7
1999	2086.87	1.1
2000	2122.55	1.7
2001	2150.63	1.3
2002	2175.07	1.1
2003	2204.61	1.4
2004	2233.76	1.3
2005	2261.19	1.2
2006	2286.87	1.1
2007	2310.70	1.0
2008	2333.15	1.0
2009	2355.17	0.9
2010	2376.85	0.9
2011	2399.36	0.9
2012	2421.81	0.9
2013	2445.26	1.0
2014	2469.06	1.0
2015	2492.62	1.0
2016	2515.84	0.9
2017	2539.62	0.9
2018	2562.95	0.9
2019	2586.61	0.9

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
ENDOGENOUS VARIABLES

Variable	Label	Mean
YEAR	YEAR	1997.00
EIM_KPC	ENERGY SALES, MINEPOWER	865.9899178

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
ENDOGENOUS VARIABLES

OBS	YEAR	EIM_KPC
1	1975	405.11
2	1976	463.02
3	1977	508.13
4	1978	554.16
5	1979	718.16
6	1980	763.27
7	1981	805.88
8	1982	851.29
9	1983	812.71
10	1984	851.19
11	1985	890.55
12	1986	881.70
13	1987	902.84
14	1988	911.86
15	1989	984.60
16	1990	1041.79
17	1991	1039.88
18	1992	1057.46
19	1993	1084.54
20	1994	1106.37
21	1995	1073.92
22	1996	1098.18
23	1997	1111.15
24	1998	.
25	1999	.
26	2000	.
27	2001	.
28	2002	.
29	2003	.
30	2004	.
31	2005	.
32	2006	.
33	2007	.
34	2008	.
35	2009	.
36	2010	.
37	2011	.
38	2012	.
39	2013	.
40	2014	.
41	2015	.
42	2016	.
43	2017	.
44	2018	.
45	2019	.

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
EXOGENOUS VARIABLES

Variable	Label	Mean
YEAR	YEAR	1997.00
D83	BINARY VARIABLE-1983	0.0222222
D93	BINARY VARIABLE-1993	0.0222222
D97ON	BINARY VARIABLE-1997 ON	0.5111111
QCX	SERVICE AREA COAL PRODUCTION	104.2162640
PIMNDX	REAL MINE PWR ELC PRICE INDX, 1997=1.00	1.2293333

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
EXOGENOUS VARIABLES

OBS	YEAR	D83	D93	D970N	QCX	PIMNDX
1	1975	0	0	0	61.239	1.81
2	1976	0	0	0	65.348	1.68
3	1977	0	0	0	68.948	1.90
4	1978	0	0	0	68.312	1.87
5	1979	0	0	0	77.628	1.79
6	1980	0	0	0	79.085	1.63
7	1981	0	0	0	86.782	1.70
8	1982	0	0	0	85.800	1.73
9	1983	1	0	0	71.398	1.79
10	1984	0	0	0	92.824	1.79
11	1985	0	0	0	96.575	1.99
12	1986	0	0	0	93.447	2.01
13	1987	0	0	0	98.195	1.77
14	1988	0	0	0	93.387	1.62
15	1989	0	0	0	103.173	1.53
16	1990	0	0	0	106.278	1.47
17	1991	0	0	0	95.820	1.38
18	1992	0	0	0	98.315	1.29
19	1993	0	1	0	108.345	1.19
20	1994	0	0	0	105.291	1.15
21	1995	0	0	0	100.661	1.10
22	1996	0	0	0	99.131	0.97
23	1997	0	0	1	104.513	1.00
24	1998	0	0	1	105.981	0.98
25	1999	0	0	1	107.470	0.95
26	2000	0	0	1	108.980	0.93
27	2001	0	0	1	110.512	0.90
28	2002	0	0	1	112.064	0.87
29	2003	0	0	1	113.639	0.85
30	2004	0	0	1	114.795	0.85
31	2005	0	0	1	115.919	0.85
32	2006	0	0	1	116.993	0.85
33	2007	0	0	1	118.069	0.85
34	2008	0	0	1	119.155	0.85
35	2009	0	0	1	120.262	0.85
36	2010	0	0	1	121.370	0.85
37	2011	0	0	1	122.543	0.85
38	2012	0	0	1	123.735	0.85
39	2013	0	0	1	124.927	0.85
40	2014	0	0	1	126.130	0.85
41	2015	0	0	1	127.355	0.85
42	2016	0	0	1	128.339	0.85
43	2017	0	0	1	129.334	0.85
44	2018	0	0	1	130.329	0.85
45	2019	0	0	1	131.335	0.85

KENTUCKY POWER COhrANY
MINE POWER ENERGY SALES
MODEL ESTIMATION

SYSLIN Procedure
Ordinary Least Squares Estimation

Model: EIM_KPC
Dependent variable: EIM_KPC ENERGY SALES, MINEPOWER

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Prob>F
Model	5	993020.68924	198604.13785	133.249	0.0001
Error	17	25338.08468	1490.47557		
C Total	22	1018358.7739			

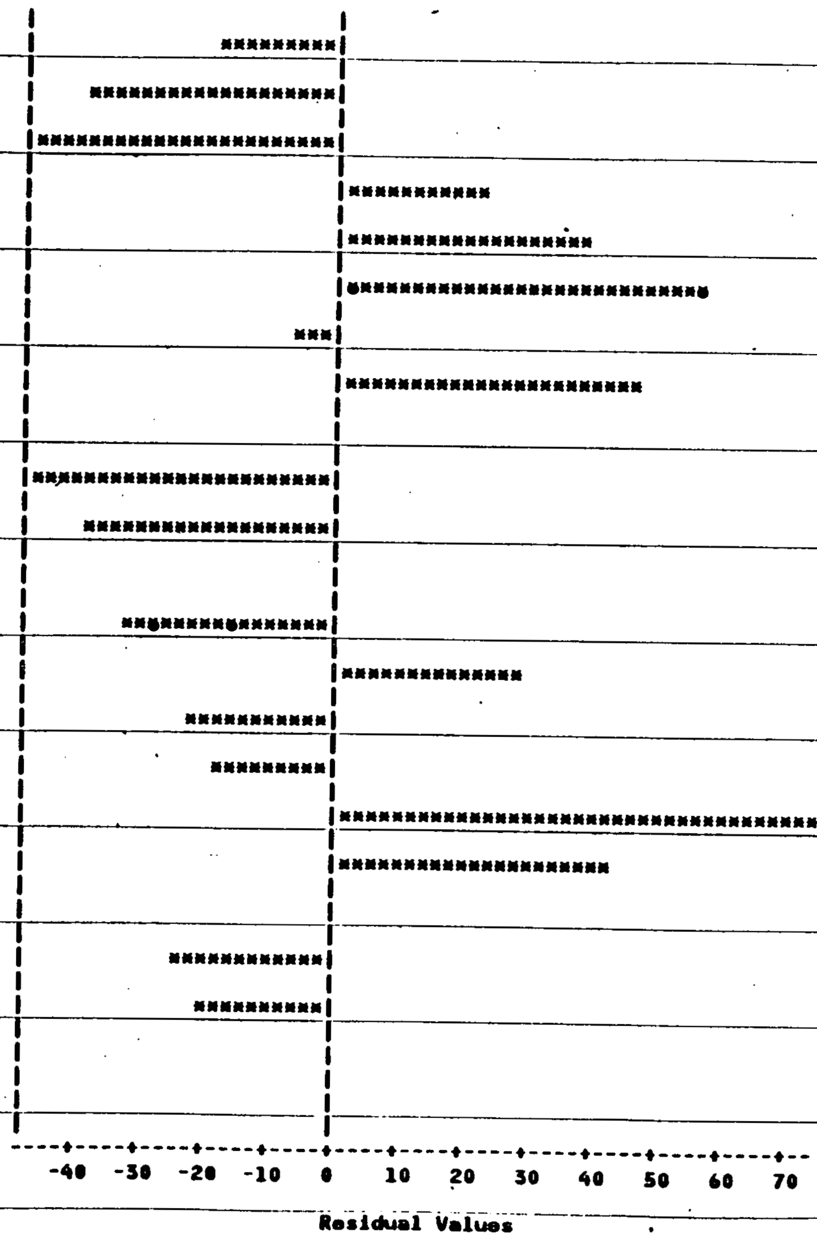
Root MSE	38.60668	R-Square	0.9751
Dep Mean	865.98992	Adj R-SQ	0.9678
C.V.	4.45810		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	T for H0: Parameter=0	Prob > |T|	Variable Label
INTERCEP	1	-3799.470555	304.039459	-12.497	0.0001	Intercept
LQCX	1	1133.426784	57.058596	19.864	0.0001	SERVICE AREA COAL PRODUCTION, LOG
LPIM5	1	-315.351929	67.797735	-4.651	0.0002	MINE PWR ELEC PRICE, 5-YR MVNG AVE, LOG
D97ON	1	-63.378848	47.099240	-1.346	0.1961	BINARY VARIABLE-1997 ON
D93	1	-60.651679	41.837752	-1.450	0.1653	BINARY VARIABLE-1993
D83	1	213.349471	41.025835	5.200	0.0001	BINARY VARIABLE-1983

Durbin-Watson	1.469
(For Number of Obs.)	23
1st Order Autocorrelation	0.259

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
MODEL RESIDUALS



YEAR	Residual Values Sum
1975	-17.68569
1976	-37.27403
1977	-45.01853
1978	22.57808
1979	38.12172
1980	55.94542
1981	-5.91791
1982	46.48705
1983	0.00000
1984	-45.46943
1985	-38.09494
1986	0.80673
1987	-32.90612
1988	27.31233
1989	-22.14706
1990	-17.38658
1991	73.59981
1992	41.98925
1993	0.00000
1994	-24.34748
1995	-20.32805
1996	-0.18455
1997	0.00000

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
ACTUAL AND FORECAST

YEAR	ENERGY SALES	GROWTH RATE
1975	405.11	.
1976	463.02	14.3
1977	508.13	9.7
1978	554.16	9.1
1979	718.16	29.6
1980	763.27	6.3
1981	805.88	5.6
1982	851.29	5.6
1983	812.71	-4.5
1984	851.19	4.7
1985	890.55	4.6
1986	881.70	-1.0
1987	902.84	2.4
1988	911.86	1.0
1989	984.60	8.0
1990	1041.79	5.8
1991	1039.88	-0.2
1992	1057.46	1.7
1993	1084.54	2.6
1994	1106.37	2.0
1995	1073.92	-2.9
1996	1098.18	2.3
1997	1111.15	1.2
1998	1139.13	2.5
1999	1166.74	2.4
2000	1198.90	2.8
2001	1219.39	1.7
2002	1243.83	2.0
2003	1268.78	2.0
2004	1287.79	1.5
2005	1304.62	1.3
2006	1318.92	1.1
2007	1331.15	0.9
2008	1341.55	0.8
2009	1352.04	0.8
2010	1362.42	0.8
2011	1373.29	0.8
2012	1384.23	0.8
2013	1395.06	0.8
2014	1405.92	0.8
2015	1416.91	0.8
2016	1425.70	0.6
2017	1434.56	0.6
2018	1443.35	0.6
2019	1452.16	0.6

PUBLIC STREET AND HIGHWAY LIGHTING ENERGY SALES

ESIMATION OF COEFFICIENTS

Autoreg Procedure

Dependent Variable = EUL_KPC KPC=PSHL ENERGY=(GWH)

Ordinary Least Squares Estimates

SSE	0.30833	DFE	17
MSE	0.018137	Root MSE	0.134674
SBC	-15.8957	AIC	-21.9066
Reg Rsq	0.9802	Total Rsq	0.9802
Durbin-Watson	1.8861		

Variable	DF	B Value	Std Error	t Ratio	Approx Prob	Variable Label
Intercept	1	-302.894714	50.342	-6.017	0.0001	
YEAR	1	0.157071	0.025	6.172	0.0001	YEAR
T82ON	1	-0.027792589	0.029	-0.970	0.3456	TIME=TREND=1982 ON
D82ON	1	54.567149	56.725	0.962	0.3496	BINARY=VARIABLE=1982 ON
D8990	1	-0.275185	0.113	-2.442	0.0258	
D93ON	1	0.288534	0.135	2.132	0.0479	BINARY=VARIABLE=1993 ON

Estimates of Autocorrelations

```
Lag  Covariance  Correlation -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

  0    0.013406     1.000000 |                    |********************|
  1    -0.00028    -0.020536 |                    |                    |
```

Preliminary MSE = 0.0134

Estimates of the Autoregressive Parameters

Lag	Coefficient	Std Error	t Ratio
1	0.02053594	0.24994728	0.082161

Yule-Walker Estimates

SSE	0.308154	DFE	16
MSE	0.01926	Root MSE	0.138779
SBC	-11.9709	AIC	-19.9194
Reg Rsq	0.9800	Total Rsq	0.9802
Durbin-Watson	1.8652		

PUBLIC STREET AND HIGHWAY LIGHTING ENERGY SALES

ESIMATION OF COEFFICIENTS

Autoreg Procedure

Variable	DF	B Value	Std Error	t Ratio	Approx Prob	Variable Label
Intercept	1	-303.745076	51.272	-5.924	0.0001	
YEAR	1	0.157502	0.026	6.076	0.0001	YEAR
T82ON	1	-0.028368329	0.029	-0.974	0.3447	TIME=TREND=1982 ON
D82ON	1	55.705085	57.684	0.966	0.3406	BINARY=VARIABLE=1982 ON
D8990	1	-0.274067	0.116	-2.371	0.0307	
D93ON	1	0.290737	0.138	2.100	0.0519	BINARY=VARIABLE=1993 ON

PUBLIC STREET AND HIGHWAY LIGHTING ENERGY SALES
ACTUAL VERSUS PREDICTED ANNUAL VALUES
1975-2019

YEAR	KPC PSHL ENERGY (GWH)	GROWTH RATE	PKP	GROWTH RATE
1975	7.2010	.	7.3212	.
1976	7.4610	3.6	7.4812	2.2
1977	7.6490	2.5	7.6366	2.1
1978	7.9150	3.5	7.7934	2.1
1979	8.0900	2.2	7.9488	2.0
1980	8.2200	1.6	8.1059	2.0
1981	8.0140	-2.5	8.2639	2.0
1982	7.9330	-1.0	7.9080	-4.3
1983	8.1330	2.5	8.0513	1.6
1984	8.2270	1.2	8.1590	1.6
1985	8.3520	1.5	8.2888	1.6
1986	8.3420	-0.1	8.4180	1.6
1987	8.4120	0.8	8.5500	1.6
1988	8.6190	2.5	8.6804	1.5
1989	8.5130	-1.2	8.5338	-1.7
1990	8.6820	2.0	8.6622	1.5
1991	9.0950	4.8	9.0646	4.6
1992	9.1860	1.0	9.1935	1.4
1993	9.4200	2.5	9.6142	4.6
1994	9.6360	2.3	9.7471	1.4
1995	10.0820	4.6	9.8745	1.3
1996	9.9100	-1.7	9.9971	1.2
1997	10.3133	4.1	10.1324	1.4
1998	.	.	10.2559	1.2
1999	.	.	10.3889	1.3
2000	.	.	10.5179	1.2
2001	.	.	10.6471	1.2
2002	.	.	10.7762	1.2
2003	.	.	10.9053	1.2
2004	.	.	11.0345	1.2
2005	.	.	11.1636	1.2
2006	.	.	11.2927	1.2
2007	.	.	11.4219	1.1
2008	.	.	11.5510	1.1
2009	.	.	11.6801	1.1
2010	.	.	11.8093	1.1
2011	.	.	11.9384	1.1
2012	.	.	12.0675	1.1
2013	.	.	12.1967	1.1
2014	.	.	12.3258	1.1
2015	.	.	12.4549	1.0
2016	.	.	12.5841	1.0
2017	.	.	12.7132	1.0
2018	.	.	12.8423	1.0
2019	.	.	12.9715	1.0

KENTUCKY POWER COMAPNY
SALES FOR RESALE TO MUNICIPAL ENERGY SALES
ENDOGENOUS AND EXOGENOUS VARIABLES

Variable	Label	N
EOM_KPC	KPC MUNICIPALS ENERGY (GWH)	24
YEAR	YEAR	45
D83	BINARY VARIABLE IN 1983	45
T8493	TIME TREND 1984-93	45
D8493	BINARY VARIABLE 1984-93	45

KENTUCKY POWER COMAPNY
SALES FOR RESALE TO MUNICIPAL ENERGY SALES
ENDOGENOUS AND EXOGENOUS VARIABLES

YEAR	EOM_KPC	YEAR	D83	T8493	D8493
1975	31.701	1975	0	0	0
1976	33.788	1976	0	0	0
1977	36.930	1977	0	0	0
1978	40.173	1978	0	0	0
1979	42.307	1979	0	0	0
1980	45.791	1980	0	0	0
1981	46.162	1981	0	0	0
1982	45.634	1982	0	0	0
1983	29.950	1983	1	0	0
1984	19.869	1984	0	1984	1
1985	20.008	1985	0	1985	1
1986	20.033	1986	0	1986	1
1987	21.234	1987	0	1987	1
1988	21.985	1988	0	1988	1
1989	29.303	1989	0	1989	1
1990	26.703	1990	0	1990	1
1991	30.937	1991	0	1991	1
1992	26.404	1992	0	1992	1
1993	27.769	1993	0	1993	1
1994	73.412	1994	0	0	0
1995	78.380	1995	0	0	0
1996	82.631	1996	0	0	0
1997	78.723	1997	0	0	0
1998	79.900	1998	0	0	0
1999	.	1999	0	0	0
2000	.	2000	0	0	0
2001	.	2001	0	0	0
2002	.	2002	0	0	0
2003	.	2003	0	0	0
2004	.	2004	0	0	0
2005	.	2005	0	0	0
2006	.	2006	0	0	0
2007	.	2007	0	0	0
2008	.	2008	0	0	0
2009	.	2009	0	0	0
2010	.	2010	0	0	0
2011	.	2011	0	0	0
2012	.	2012	0	0	0
2013	.	2013	0	0	0
2014	.	2014	0	0	0
2015	.	2015	0	0	0
2016	.	2016	0	0	0
2017	.	2017	0	0	0
2018	.	2018	0	0	0
2019	.	2019	0	0	0

KENTUCKY POWER COMAPNY
SALES FOR RESALE TO MUNICIPAL ENERGY SALES
MODEL ESTIMATION

Autoreg Procedure

Dependent Variable = EOM_KPC   KPC MUNICIPALS ENERGY (GWH)

Ordinary Least Squares Estimates

SSE	96.64275	DFE	19
MSE	5.086461	Root MSE	2.255318
SBC	117.4305	AIC	111.5403
Reg Rsq	0.9907	Total Rsq	0.9907
Durbin-Watson	1.7441		

Variable	DF	B Value	Std Error	t Ratio	Approx Prob	Variable Label
Intercept	1	-4276.947152	142.0	-30.121	0.0001	
YEAR	1	2.182107	0.0715	30.509	0.0001	YEAR
D83	1	-20.221603	2.3459	-8.620	0.0001	BINARY VARIABLE IN 1983
T8493	1	-1.005629	0.2584	-3.892	0.0010	TIME TREND 1984-93
D8493	1	1961.943383	513.8	3.819	0.0012	BINARY VARIABLE 1984-93

Estimates of Autocorrelations

Lag	Covariance	Correlation	-1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1
0	4.026781	1.000000	| |******************** |
1	0.305829	0.075949	| |** |

Preliminary MSE = 4.003554

Estimates of the Autoregressive Parameters

Lag	Coefficient	Std Error	t Ratio
1	-0.07594884	0.235021	-0.323

Yule-Walker Estimates

SSE	95.98855	DFE	18
MSE	5.332697	Root MSE	2.309263
SBC	120.4514	AIC	113.383
Reg Rsq	0.9895	Total Rsq	0.9907
Durbin-Watson	1.8435		

KENTUCKY POWER COMAPNY
SALES FOR RESALE TO MUNICIPAL ENERGY SALES
MODEL ESTIMATION

Autoreg Procedure

Variable	DF	B Value	Std Error	t Ratio	Approx Prob	Variable Label
Intercept	1	-4274.897299	155.0	-27.582	0.0001	
YEAR	1	2.181059	0.0781	27.930	0.0001	YEAR
D83	1	-20.060018	2.3958	-8.376	0.0001	BINARY VARIABLE IN 1983
T8493	1	-1.016961	0.2785	-3.651	0.0018	TIME TREND 1984-93
D8493	1	1984.509383	553.8	3.585	0.0021	BINARY VARIABLE 1984-93

KENTUCKY POWER COMPANY
SALES FOR RESALE ENERGY SALES (GWH)

	MUNICIPALS	GROWTH RATE %
ACTUAL		
1975	31.701	
1976	33.780	6.6
1977	36.938	9.3
1978	40.173	8.8
1979	42.307	5.3
1980	45.791	8.2
1981	46.142	0.8
1982	45.634	-1.1
1983	29.950	-34.4
1984	19.869	-33.7
1985	20.008	0.7
1986	20.033	0.1
1987	21.234	6.0
1988	21.983	3.5
1989	29.303	33.3
1990	26.703	-8.9
1991	30.937	15.9
1992	26.404	-14.7
1993	27.769	5.2
1994	73.412	164.4
1995	78.380	6.8
1996	82.631	5.4
1997	78.723	-4.7
1998	79.900	1.5
SHORT TERM FORECAST		
1999	84.814	6.2
2000	87.203	2.8
2001	89.400	2.5
2002	91.582	2.4
2003	93.763	2.4
2004	95.944	2.3
LONG TERM FORECAST		
2009	106.849	2.2
VERY LONG TERM FORECAST		
2019	128.660	1.9

KENTUCKY POWER COMPANY
SALES FOR RESALE ENERGY SALES (GWH)

NOTE: LONG TERM RATES ARE ANNUAL AVERAGES FROM PREVIOUSLY LISTED YEAR

LOAD FORECASTING AND ECONOMIC ANALYSIS SECTION
1999 LOAD FORECAST

Long-term Losses and Unaccounted-for Energy

KENTUCKY POWER COMPANY
LOSSES AND UNACCOUNTED FOR ENERGY REQUIREMENTS
ENDOGENOUS AND EXOGENOUS VARIABLES

Variable	Label	N
EL_KPC	KPCO LOSSES ENERGY REQUIREMENTS (GWH)	28
YEAR	YEAR	50
EE_KPC	INTERNAL ENERGY SALES (GWH)	50
ES_KPC	SYSTEM SALES (GWH)	50
ET_KPC	TOTAL SALES (GWH) - INCL. SYS. SALES	50
T80ON	TIME TREND 1980 ON	50
D80ON	BINARY VAR 1980 ON	50

KENTUCKY POWER COMPANY
LOSSES AND UNACCOUNTED FOR ENERGY REQUIREMENTS
ENDOGENOUS AND EXOGENOUS VARIABLES

OBS	EL_KPC	YEAR	EE_KPC	ES_KPC	ET_KPC	T80ON	D80ON	D8182
1	151	1970	2156.00	108.00	2264	0	0	0
2	134	1971	2222.00	155.00	2377	0	0	0
3	54	1972	2411.00	266.00	2677	0	0	0
4	113	1973	2666.00	389.00	3055	0	0	0
5	29	1974	2716.00	429.00	3145	0	0	0
6	123	1975	2878.00	650.00	3528	0	0	0
7	150	1976	3203.00	956.00	4159	0	0	0
8	330	1977	3591.00	686.00	4277	0	0	0
9	368	1978	3932.00	803.00	4735	0	0	0
10	416	1979	4262.00	1351.00	5613	0	0	0
11	505	1980	4381.00	1977.00	6358	1980	1	0
12	458	1981	4554.00	1928.00	6482	1981	1	1
13	244	1982	4479.00	1356.00	5835	1982	1	1
14	386	1983	4718.00	1264.00	5982	1983	1	0
15	402	1984	4813.00	1833.00	6646	1984	1	0
16	377	1985	4805.00	996.00	5801	1985	1	0
17	400	1986	4855.00	1396.00	6251	1986	1	0
18	380	1987	5186.00	555.00	5741	1987	1	0
19	416	1988	5445.00	738.00	6183	1988	1	0
20	455	1989	5433.00	1440.00	6873	1989	1	0
21	393	1990	5550.00	1581.00	7131	1990	1	0
22	433	1991	5740.00	792.00	6532	1991	1	0
23	409	1992	5731.00	624.00	6355	1992	1	0
24	451	1993	5903.00	711.00	6614	1993	1	0
25	431	1994	6052.00	555.00	6607	1994	1	0
26	424	1995	6390.00	637.00	7027	1995	1	0
27	450	1996	6510.00	1304.00	7816	1996	1	0
28	384	1997	6593.00	1424.00	8017	1997	1	0
29	.	1998	6685.56	1154.44	7840	1998	1	0
30	.	1999	6907.86	1450.14	8358	1999	1	0
31	.	2000	7077.59	1850.41	8928	2000	1	0
32	.	2001	7221.91	1845.09	9067	2001	1	0
33	.	2002	7357.46	1865.54	9223	2002	1	0
34	.	2003	7509.54	1860.46	9370	2003	1	0
35	.	2004	7653.83	1876.17	9530	2004	1	0
36	.	2005	7792.42	1865.58	9658	2005	1	0
37	.	2006	7924.05	1879.95	9804	2006	1	0
38	.	2007	8048.25	1897.75	9946	2007	1	0
39	.	2008	8166.53	1756.47	9923	2008	1	0
40	.	2009	8286.35	1615.65	9902	2009	1	0
41	.	2010	8407.57	1475.43	9883	2010	1	0
42	.	2011	8531.85	1348.15	9880	2011	1	0
43	.	2012	8658.79	1312.21	9971	2012	1	0
44	.	2013	8788.93	1273.07	10062	2013	1	0
45	.	2014	8921.55	1159.45	10081	2014	1	0
46	.	2015	9056.55	1045.45	10102	2015	1	0
47	.	2016	9191.60	932.40	10124	2016	1	0
48	.	2017	9329.46	819.54	10149	2017	1	0

KENTUCKY POWER COMPANY
LOSSES AND UNACCOUNTED FOR ENERGY REQUIREMENTS
ENDOGENOUS AND EXOGENOUS VARIABLES

OBS	EL_KPC	YEAR	EE_KPC	ES_KPC	ET_KPC	T80ON	D80ON	D8182
49	.	2018	9469.59	706.412	10176	2018	1	0
50	.	2019	9612.71	628.285	10241	2019	1	0

KENTUCKY POWER COMPANY
LOSSES AND UNACCOUNTED FOR ENERGY REQUIREMENTS
MODEL ESTIMATION WITH ENERGY SALES

SYSLIN Procedure
Ordinary Least Squares Estimation

Model: EL_KPC
Dependent variable: EL_KPC KPCO LOSSES ENERGY REQUIREMENTS (GWH)

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Prob>F
Model	3	389982.48779	129994.16268	21.779	0.0001
Error	24	143253.36936	5968.89039		
C Total	27	533235.85714			

Root MSE	77.25859	R-Square	0.7314
Dep Mean	328.07143	Adj R-SQ	0.6978
C.V.	23.54932		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	T for H0: Parameter=0	Prob > |T|	Variable Label
INTERCEP	1	-64.222810	52.011646	-1.235	0.2289	Intercept
EE_KPC	1	0.068328	0.012349	5.533	0.0001	INTERNAL ENERGY SALES (GWH)
ES_KPC	1	0.088119	0.034002	2.592	0.0160	SYSTEM SALES (GWH)
D8182	1	-38.072736	62.001201	-0.614	0.5450	BINARY VARIABLE YEARS 1981-82

Durbin-Watson	1.087
(For Number of Obs.)	28
1st Order Autocorrelation	0.334

KENTUCKY POWER COMPANY
LOSSES AND UNACCOUNTED FOR ENERGY REQUIREMENTS
MODEL ESTIMATION WITH TIME TREND

SYSLIN Procedure
Ordinary Least Squares Estimation

Model: EL_KPC
Dependent variable: EL_KPC KPCO LOSSES ENERGY REQUIREMENTS (GWH)

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Prob>F
Model	5	424078.72325	84815.74465	17.094	0.0001
Error	22	109157.13392	4961.68791		
C Total	27	533235.85714			

Root MSE	70.43925	R-Square	0.7953
Dep Mean	328.07143	Adj R-SQ	0.7488
C.V.	21.47071		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	T for H0: Parameter=0	Prob > |T|	Variable Label
INTERCEP	1	-31659	29408	-1.077	0.2935	Intercept
ET_KPC	1	0.050769	0.036147	1.405	0.1741	TOTAL SALES (GWH) - INCL. SYS. SALES
YEAR	1	16.036517	14.949790	1.073	0.2950	YEAR
T80ON	1	-22.675305	12.809608	-1.770	0.0906	TIME TREND 1980 ON
D80ON	1	44944	25354	1.773	0.0901	BINARY VAR 1980 ON
D8182	1	-91.315037	60.771704	-1.503	0.1472	BINARY VARIABLE YEARS 1981-82

Durbin-Watson	1.154
(For Number of Obs.)	28
1st Order Autocorrelation	0.297

KENTUCKY POWER COMPANY
LOSSES AND UNACCOUNTED FOR ENERGY REQUIREMENTS (GWH)

	SALES METHOD	GROWTH RATE %	TREND METHOD	GROWTH RATE %	AVERAGE LOSSES	GROWTH RATE %
ACTUAL						
1975	189.7		192.0		123.0	
1976	238.9	25.9	240.1	25.0	150.0	22.0
1977	241.6	1.1	262.1	9.2	330.0	120.0
1978	275.2	13.9	301.4	15.0	368.0	11.5
1979	346.0	25.7	362.0	20.1	416.0	13.0
1980	409.3	18.3	462.4	27.7	505.0	21.4
1981	378.8	-7.5	370.7	-19.8	458.0	-9.3
1982	323.2	-14.7	331.3	-10.7	244.0	-46.7
1983	369.5	14.3	423.4	27.8	386.0	58.2
1984	426.2	15.3	450.5	6.4	402.0	4.1
1985	351.9	-17.4	400.9	-11.0	377.0	-6.2
1986	390.5	11.0	417.1	4.0	400.0	6.1
1987	339.0	-13.2	384.6	-7.8	380.0	-5.0
1988	372.9	10.0	400.4	4.1	416.0	9.5
1989	433.9	16.4	428.8	7.1	455.0	9.4
1990	454.3	4.7	435.3	1.5	393.0	-13.6
1991	397.8	-12.4	398.2	-8.5	433.0	10.2
1992	382.4	-3.9	382.6	-3.9	409.0	-5.5
1993	401.8	5.1	389.1	1.7	451.0	10.3
1994	398.2	-0.9	382.1	-1.8	431.0	-4.4
1995	428.5	7.6	396.8	3.8	424.0	-1.6
1996	495.5	15.6	430.1	8.4	450.0	6.1
1997	511.7	3.3	433.8	0.9	304.0	-32.4
SHORT TERM FORECAST						
1998	494.2	-3.4	418.0	-3.6	456.1	50.0
1999	535.6	8.4	437.8	4.7	486.7	6.7
2000	582.4	8.8	460.1	5.1	521.3	7.1
2001	591.8	1.6	460.5	0.1	526.2	0.9
2002	602.9	1.9	461.8	0.3	532.3	1.2
2003	612.8	1.6	462.6	0.2	537.7	1.0
2004	624.1	1.8	464.1	0.3	544.1	1.2
LONG TERM FORECAST						
2009	644.5	0.6	449.0	-0.6	547.1	0.1
VERY LONG TERM FORECAST						
2019	640.0	0.1	400.6	-1.2	524.3	-0.4

KENTUCKY POWER COMPANY
LOSSES AND UNACCOUNTED FOR ENERGY REQUIREMENTS (GWH)

NOTE: LONG TERM RATES ARE ANNUAL AVERAGES FROM PREVIOUSLY LISTED YEAR

LOAD FORECASTING AND ECONOMIC ANALYSIS SECTION
1999 LOAD FORECAST

KENTUCKY POWER COMPANY
LOSSES AND UNACCOUNTED FOR ENERGY REQUIREMENTS (GWH)

YEAR	LOSSES SALES METHOD	LOSSES TREND METHOD	KPCO LOSSES - ENERGY REQUIREMENTS (GWH)
1975	189.703	192.026	123.000
1976	238.874	240.098	150.000
1977	241.598	262.125	330.000
1978	275.203	301.414	368.000
1979	346.041	362.026	416.000
1980	409.334	462.400	505.000
1981	378.764	370.743	458.000
1982	323.236	331.257	244.000
1983	369.532	423.394	386.000
1984	426.163	458.466	402.000
1985	351.868	408.927	377.000
1986	390.524	417.134	400.000
1987	339.033	384.603	380.000
1988	372.856	400.404	416.000
1989	433.895	428.796	455.000
1990	454.314	435.256	393.000
1991	397.771	398.206	433.000
1992	382.352	382.581	409.000
1993	401.771	389.091	451.000
1994	398.205	382.097	431.000
1995	428.526	396.781	424.000
1996	495.500	430.098	450.000
1997	511.746	433.765	304.000
1998	494.188	418.059	456.109
1999	535.563	437.000	486.681
2000	582.432	460.899	521.266
2001	591.826	460.517	526.171
2002	602.888	461.798	532.343
2003	612.832	462.623	537.727
2004	624.075	464.107	544.891
2005	632.612	463.966	548.289
2006	642.872	464.740	553.806
2007	652.927	465.310	559.118
2008	648.559	457.504	553.031
2009	644.337	449.799	547.068
2010	640.264	442.195	541.229
2011	637.540	435.404	536.472
2012	643.046	433.388	538.216
2013	648.498	431.366	539.928
2014	647.539	425.692	536.616
2015	646.718	420.119	533.419
2016	645.984	414.597	530.298
2017	645.458	409.228	527.343
2018	645.064	403.959	524.512
2019	647.959	400.621	524.298

KENTUCKY POWER
NORMAL PEAK TEMPERATURES

MONTH	TUM_KPC	TUS_KPC
1	16.2667	10.7333
2	23.6667	.
3	30.5333	.
4	41.3000	.
5	71.7667	.
6	78.3000	.
7	81.4667	.
8	80.5333	81.8667
9	76.9643	.
10	48.4643	.
11	34.0000	.
12	24.0357	.

KENTUCKY POWER
NORMAL PEAK TEMPERATURES

Variable	Label	N
PU_KPC	UNCURTAILED PEAK	176
D2	SEASONAL BINARY MAR-APR	176
D3	SEASONAL BINARY MAY-JUN	176
D4	SEASONAL BINARY JUL-AUG	176
D5	SEASONAL BINARY SEP-OCT	176
D6	SEASONAL BINARY NOV-DEC	176
E1	INTERNAL ENERGY JAN-FEB	176
E2	INTERNAL ENERGY MAR-APR	176
E3	INTERNAL ENERGY MAY-JUN	176
E4	INTERNAL ENERGY JUL-AUG	176
E5	INTERNAL ENERGY SEP-OCT	176
E6	INTERNAL ENERGY NOV-DEC	176
T1	TEMP IF <=32 OTHERWISE 0	176
T2	TEMP IF <=62 OTHERWISE 0	176
T3	TEMP IF >=62 OTHERWISE 0	176
T4	TEMP IF >=72 OTHERWISE 0	176
ZT1	(TIME TREND)*T1	176
ZT2	(TIME TREND)*T2	176
ZT3	(TIME TREND)*T3	176
ZT4	(TIME TREND)*T4	176
M2	MONTHLY BINARY FEB	176
M4	MONTHLY BINARY APR	176
M6	MONTHLY BINARY JUN	176
M8	MONTHLY BINARY AUG	176
M10	MONTHLY BINARY OCT	176
M12	MONTHLY BINARY DEC	176

KENTUCKY POWER
REGRESSION RESULTS

Model: PU_KPC
Dependent Variable: PU_KPC UNCURTAILED PEAK

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Prob>F
Model	25	3212447.3511	128497.89404	99.706	0.0001
Error	150	193315.53527	1288.77024		
C Total	175	3405762.8864			

Root MSE	35.89945	R-square	0.9432
Dep Mean	1000.32955	Adj R-sq	0.9338
C.V.	3.58876		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	T for H0: Parameter=0	Prob > |T|
INTERCEP	1	101.660518	190.21838670	0.534	0.5938
D2	1	24.796793	126.70628814	0.196	0.8451
D3	1	30.675050	186.00862296	0.165	0.8692
D4	1	127.613218	201.49591602	0.633	0.5275
D5	1	120.406062	174.23977800	0.691	0.4906
D6	1	118.442570	117.60028887	1.007	0.3155
E1	1	1.356571	0.31021039	4.373	0.0001
E2	1	1.401309	0.32329397	4.334	0.0001
E3	1	1.396794	0.26139196	5.344	0.0001
E4	1	1.217340	0.26236319	4.640	0.0001
E5	1	1.297097	0.21395034	6.063	0.0001
E6	1	1.277721	0.28522469	4.480	0.0001
T1	1	0.021653	1.11938212	0.019	0.9846
T2	1	4.500234	0.87412176	5.148	0.0001
T3	1	5.487143	3.09919936	1.771	0.0787
T4	1	5.560474	3.81240315	1.459	0.1468
ZT1	1	-0.077302	0.19041291	-0.406	0.6853
ZT2	1	0.268502	0.12894462	2.082	0.0390
ZT3	1	0.596527	0.33041827	1.805	0.0730
ZT4	1	-0.292167	0.67109612	-0.435	0.6639
M2	1	96.332685	26.16803866	3.681	0.0003
M4	1	49.563908	24.46989431	2.026	0.0446
M6	1	36.083419	14.41756521	2.503	0.0134
M8	1	-11.330440	13.29343863	-0.852	0.3954
M10	1	-6.105225	30.68404478	-0.199	0.8426
M12	1	-42.444193	24.60973996	-1.725	0.0866

Variable	DF	Variable Label
INTERCEP	1	Intercept
D2	1	SEASONAL BINARY MAR-APR
D3	1	SEASONAL BINARY MAY-JUN
D4	1	SEASONAL BINARY JUL-AUG
D5	1	SEASONAL BINARY SEP-OCT
D6	1	SEASONAL BINARY NOV-DEC

Variable	DF	Variable Label
E1	1	INTERNAL ENERGY JAN-FEB
E2	1	INTERNAL ENERGY MAR-APR
E3	1	INTERNAL ENERGY MAY-JUN
E4	1	INTERNAL ENERGY JUL-AUG
E5	1	INTERNAL ENERGY SEP-OCT
E6	1	INTERNAL ENERGY NOV-DEC
T1	1	TEMP IF <=32 OTHERWISE 0
T2	1	TEMP IF <=62 OTHERWISE 0
T3	1	TEMP IF >=62 OTHERWISE 0
T4	1	TEMP IF >=72 OTHERWISE 0
ZT1	1	(TIME TREND)*T1
ZT2	1	(TIME TREND)*T2
ZT3	1	(TIME TREND)*T3
ZT4	1	(TIME TREND)*T4
M2	1	MONTHLY BINARY FEB
M4	1	MONTHLY BINARY APR
M6	1	MONTHLY BINARY JUN
M8	1	MONTHLY BINARY AUG
M10	1	MONTHLY BINARY OCT
M12	1	MONTHLY BINARY DEC

Durbin-Watson D	1.943
(For Number of Obs.)	176
1st Order Autocorrelation	0.017

KENTUCKY POWER
REGRESSION RESULTS

Dependent Variable: PU_KPC
Test: SEASONS

Numerator:	669.2837	DF:	5	F value:	0.5193
Denominator:	1288.77	DF:	150	Prob>F:	0.7614

Dependent Variable: PU_KPC
Test: MONTHS

Numerator:	4577.4710	DF:	6	F value:	3.5518
Denominator:	1288.77	DF:	150	Prob>F:	0.0026

Dependent Variable: PU_KPC
Test: ENERGY

Numerator:	9591.6519	DF:	6	F value:	7.4425
Denominator:	1288.77	DF:	150	Prob>F:	0.0001

Dependent Variable: PU_KPC
Test: WRESP

Numerator:	28215.5335	DF:	8	F value:	21.8934
Denominator:	1288.77	DF:	150	Prob>F:	0.0001

Dependent Variable: PU_KPC
Test: TEMP

Numerator:	50727.7288	DF:	4	F value:	39.3613
Denominator:	1288.77	DF:	150	Prob>F:	0.0001

Dependent Variable: PU_KPC
Test: TRENTEMP

Numerator:	3638.1728	DF:	4	F value:	2.8230
Denominator:	1288.77	DF:	150	Prob>F:	0.0270

Analysis Variable : R Residual

Mean
21.1458960

KENTUCKY POWER
MEAN ERROR FOR SUMMER PEAK

Analysis Variable : R Residual

Mean
10.9192399

KENTUCKY POWER
MW RESIDUALS

YEAR	MONTH	TU_KPC	TUM_KPC	TUS_KPC
1984	1	5.0	16.3	10.7
1984	2	22.5	23.7	.
1984	3	22.5	30.5	.
1984	4	46.0	41.3	.
1984	5	48.5	71.8	.
1984	6	82.5	78.3	.
1984	7	81.5	81.5	.
1984	8	79.0	80.5	81.9
1984	9	73.5	77.0	.
1984	10	56.5	48.5	.
1984	11	29.0	34.0	.
1984	12	15.0	24.0	.
1985	1	-4.0	16.3	10.7
1985	2	17.0	23.7	.
1985	3	42.5	30.5	.
1985	4	31.5	41.3	.
1985	5	73.5	71.8	.
1985	6	74.5	78.3	.
1985	7	78.5	81.5	.
1985	8	79.5	80.5	81.9
1985	9	81.0	77.0	.
1985	10	51.0	48.5	.
1985	11	38.5	34.0	.
1985	12	16.5	24.0	.
1986	1	10.0	16.3	10.7
1986	2	15.0	23.7	.
1986	3	24.5	30.5	.
1986	4	41.0	41.3	.
1986	5	76.5	71.8	.
1986	6	77.0	78.3	.
1986	7	82.0	81.5	.
1986	8	81.0	80.5	81.9
1986	9	77.0	77.0	.
1986	10	63.0	48.5	.
1986	11	26.5	34.0	.
1986	12	37.0	24.0	.
1987	1	13.5	16.3	10.7
1987	2	34.5	23.7	.
1987	3	29.0	30.5	.
1987	4	32.5	41.3	.
1987	5	76.5	71.8	.
1987	6	76.5	78.3	.
1987	7	81.0	81.5	.
1987	8	83.5	80.5	81.9
1987	9	74.5	77.0	.
1987	10	39.5	48.5	.
1987	11	37.5	34.0	.
1987	12	26.0	24.0	.
1988	1	7.0	16.3	10.7
1988	2	27.5	23.7	.
1988	3	26.5	30.5	.
1988	4	45.5	41.3	.
1988	5	73.0	71.8	.
1988	6	84.0	78.3	.
1988	7	88.5	81.5	.

KENTUCKY POWER
MW RESIDUALS

YEAR	MONTH	TU_KPC	TUM_KPC	TUS_KPC
1988	8	84.5	80.5	81.9
1988	9	77.0	77.0	.
1988	10	43.0	48.5	.
1988	11	36.0	34.0	.
1988	12	20.0	24.0	.
1989	1	31.5	16.3	10.7
1989	2	15.0	23.7	.
1989	3	32.5	30.5	.
1989	4	35.5	41.3	.
1989	5	78.0	71.8	.
1989	6	80.0	78.3	.
1989	7	82.0	81.5	.
1989	8	77.0	80.5	81.9
1989	9	77.5	77.0	.
1989	10	39.0	48.5	.
1989	11	36.5	34.0	.
1989	12	-3.0	24.0	.
1990	1	33.5	16.3	10.7
1990	2	23.5	23.7	.
1990	3	33.5	30.5	.
1990	4	50.5	41.3	.
1990	5	73.0	71.8	.
1990	6	80.5	78.3	.
1990	7	83.5	81.5	.
1990	8	80.5	80.5	81.9
1990	9	82.0	77.0	.
1990	10	51.0	48.5	.
1990	11	35.5	34.0	.
1990	12	42.0	24.0	.
1991	1	28.5	16.3	10.7
1991	2	18.0	23.7	.
1991	3	44.0	30.5	.
1991	4	45.0	41.3	.
1991	5	81.5	71.8	.
1991	6	77.0	78.3	.
1991	7	84.5	81.5	.
1991	8	80.5	80.5	81.9
1991	9	82.0	77.0	.
1991	10	47.0	48.5	.
1991	11	28.0	34.0	.
1991	12	23.5	24.0	.
1992	1	12.5	16.3	10.7
1992	2	34.5	23.7	.
1992	3	25.5	30.5	.
1992	4	33.0	41.3	.
1992	5	70.5	71.8	.
1992	6	75.5	78.3	.
1992	7	81.0	81.5	.
1992	8	80.0	80.5	81.9
1992	9	76.0	77.0	.
1992	10	40.5	48.5	.
1992	11	35.5	34.0	.
1992	12	31.5	24.0	.
1993	1	31.5	16.3	10.7
1993	2	18.5	23.7	.

KENTUCKY POWER
MW RESIDUALS

YEAR	MONTH	TU_KPC	TUM_KPC	TUS_KPC
1993	3	32.5	30.5	.
1993	4	45.0	41.3	.
1993	5	75.0	71.8	.
1993	6	78.0	78.3	.
1993	7	82.5	81.5	.
1993	8	82.5	80.5	81.9
1993	9	78.5	77.0	.
1993	10	54.5	48.5	.
1993	11	35.5	34.0	.
1993	12	15.5	24.0	.
1994	1	-7.0	16.3	10.7
1994	2	23.0	23.7	.
1994	3	35.0	30.5	.
1994	4	49.0	41.3	.
1994	5	74.0	71.8	.
1994	6	82.5	78.3	.
1994	7	79.5	81.5	.
1994	8	78.0	80.5	81.9
1994	9	77.0	77.0	.
1994	10	47.5	48.5	.
1994	11	39.0	34.0	.
1994	12	36.0	24.0	.
1995	1	12.0	16.3	10.7
1995	2	20.5	23.7	.
1995	3	29.0	30.5	.
1995	4	37.0	41.3	.
1995	5	76.5	71.8	.
1995	6	76.0	78.3	.
1995	7	81.0	81.5	.
1995	8	82.5	80.5	81.9
1995	9	72.5	77.0	.
1995	10	49.5	48.5	.
1995	11	34.5	34.0	.
1995	12	22.5	24.0	.
1996	1	31.5	16.3	10.7
1996	2	8.5	23.7	.
1996	3	15.5	30.5	.
1996	4	42.0	41.3	.
1996	5	79.5	71.8	.
1996	6	78.0	78.3	.
1996	7	76.5	81.5	.
1996	8	80.0	80.5	81.9
1996	9	74.0	77.0	.
1996	10	57.0	48.5	.
1996	11	32.5	34.0	.
1996	12	22.0	24.0	.
1997	1	10.0	16.3	10.7
1997	2	35.5	23.7	.
1997	3	39.5	30.5	.
1997	4	37.5	41.3	.
1997	5	47.5	71.8	.
1997	6	76.5	78.3	.
1997	7	80.0	81.5	.
1997	8	79.5	80.5	81.9
1997	9	75.0	77.0	.

KENTUCKY POWER
MW RESIDUALS

YEAR	MONTH	TU_KPC	TUM_KPC	TUS_KPC
1997	10	39.5	48.5	.
1997	11	31.5	34.0	.
1997	12	32.0	24.0	.
1998	1	28.5	16.3	10.7
1998	2	41.5	23.7	.
1998	3	26.0	30.5	.
1998	4	48.5	41.3	.
1998	5	73.0	71.8	.
1998	6	76.0	78.3	.
1998	7	80.0	81.5	.
1998	8	80.0	80.5	81.9
1998	9	77.0	77.0	.
1998	10	48.5	48.5	.
1998	11	34.0	34.0	.
1998	12	24.0	24.0	.
1999	1	10.7	16.3	10.7
1999	2	23.7	23.7	.
1999	3	30.5	30.5	.
1999	4	41.3	41.3	.
1999	5	71.8	71.8	.
1999	6	78.3	78.3	.
1999	7	81.5	81.5	.
1999	8	81.9	80.5	81.9
1999	9	77.0	77.0	.
1999	10	48.5	48.5	.
1999	11	34.0	34.0	.
1999	12	24.0	24.0	.
2000	1	10.7	16.3	10.7
2000	2	23.7	23.7	.
2000	3	30.5	30.5	.
2000	4	41.3	41.3	.
2000	5	71.8	71.8	.
2000	6	78.3	78.3	.
2000	7	81.5	81.5	.
2000	8	81.9	80.5	81.9
2000	9	77.0	77.0	.
2000	10	48.5	48.5	.
2000	11	34.0	34.0	.
2000	12	24.0	24.0	.
2001	1	10.7	16.3	10.7
2001	2	23.7	23.7	.
2001	3	30.5	30.5	.
2001	4	41.3	41.3	.
2001	5	71.8	71.8	.
2001	6	78.3	78.3	.
2001	7	81.5	81.5	.
2001	8	81.9	80.5	81.9
2001	9	77.0	77.0	.
2001	10	48.5	48.5	.
2001	11	34.0	34.0	.
2001	12	24.0	24.0	.
2002	1	10.7	16.3	10.7
2002	2	23.7	23.7	.
2002	3	30.5	30.5	.
2002	4	41.3	41.3	.

KENTUCKY POWER
MW RESIDUALS

YEAR	MONTH	TU_KPC	TUM_KPC	TUS_KPC
2002	5	71.8	71.8	.
2002	6	78.3	78.3	.
2002	7	81.5	81.5	.
2002	8	81.9	80.5	81.9
2002	9	77.0	77.0	.
2002	10	48.5	48.5	.
2002	11	34.0	34.0	.
2002	12	24.0	24.0	.
2003	1	10.7	16.3	10.7
2003	2	23.7	23.7	.
2003	3	30.5	30.5	.
2003	4	41.3	41.3	.
2003	5	71.8	71.8	.
2003	6	78.3	78.3	.
2003	7	81.5	81.5	.
2003	8	81.9	80.5	81.9
2003	9	77.0	77.0	.
2003	10	48.5	48.5	.
2003	11	34.0	34.0	.
2003	12	24.0	24.0	.
2004	1	10.7	16.3	10.7
2004	2	23.7	23.7	.
2004	3	30.5	30.5	.
2004	4	41.3	41.3	.
2004	5	71.8	71.8	.
2004	6	78.3	78.3	.
2004	7	81.5	81.5	.
2004	8	81.9	80.5	81.9
2004	9	77.0	77.0	.
2004	10	48.5	48.5	.
2004	11	34.0	34.0	.
2004	12	24.0	24.0	.
2005	1	10.7	16.3	10.7
2005	2	23.7	23.7	.
2005	3	30.5	30.5	.
2005	4	41.3	41.3	.
2005	5	71.8	71.8	.
2005	6	78.3	78.3	.
2005	7	81.5	81.5	.
2005	8	81.9	80.5	81.9
2005	9	77.0	77.0	.
2005	10	48.5	48.5	.
2005	11	34.0	34.0	.
2005	12	24.0	24.0	.
2006	1	10.7	16.3	10.7
2006	2	23.7	23.7	.
2006	3	30.5	30.5	.
2006	4	41.3	41.3	.
2006	5	71.8	71.8	.
2006	6	78.3	78.3	.
2006	7	81.5	81.5	.
2006	8	81.9	80.5	81.9
2006	9	77.0	77.0	.
2006	10	48.5	48.5	.
2006	11	34.0	34.0	.

KENTUCKY POWER
MW RESIDUALS

YEAR	MONTH	TU_KPC	TUM_KPC	TUS_KPC
2006	12	24.0	24.0	.
2007	1	10.7	16.3	10.7
2007	2	23.7	23.7	.
2007	3	30.5	30.5	.
2007	4	41.3	41.3	.
2007	5	71.8	71.8	.
2007	6	78.3	78.3	.
2007	7	81.5	81.5	.
2007	8	81.9	80.5	81.9
2007	9	77.0	77.0	.
2007	10	48.5	48.5	.
2007	11	34.0	34.0	.
2007	12	24.0	24.0	.
2008	1	10.7	16.3	10.7
2008	2	23.7	23.7	.
2008	3	30.5	30.5	.
2008	4	41.3	41.3	.
2008	5	71.8	71.8	.
2008	6	78.3	78.3	.
2008	7	81.5	81.5	.
2008	8	81.9	80.5	81.9
2008	9	77.0	77.0	.
2008	10	48.5	48.5	.
2008	11	34.0	34.0	.
2008	12	24.0	24.0	.
2009	1	10.7	16.3	10.7
2009	2	23.7	23.7	.
2009	3	30.5	30.5	.
2009	4	41.3	41.3	.
2009	5	71.8	71.8	.
2009	6	78.3	78.3	.
2009	7	81.5	81.5	.
2009	8	81.9	80.5	81.9
2009	9	77.0	77.0	.
2009	10	48.5	48.5	.
2009	11	34.0	34.0	.
2009	12	24.0	24.0	.
2010	1	10.7	16.3	10.7
2010	2	23.7	23.7	.
2010	3	30.5	30.5	.
2010	4	41.3	41.3	.
2010	5	71.8	71.8	.
2010	6	78.3	78.3	.
2010	7	81.5	81.5	.
2010	8	81.9	80.5	81.9
2010	9	77.0	77.0	.
2010	10	48.5	48.5	.
2010	11	34.0	34.0	.
2010	12	24.0	24.0	.
2011	1	10.7	16.3	10.7
2011	2	23.7	23.7	.
2011	3	30.5	30.5	.
2011	4	41.3	41.3	.
2011	5	71.8	71.8	.
2011	6	78.3	78.3	.

KENTUCKY POWER
MW RESIDUALS

YEAR	MONTH	TU_KPC	TUM_KPC	TUS_KPC
2011	7	81.5	81.5	.
2011	8	81.9	80.5	81.9
2011	9	77.0	77.0	.
2011	10	48.5	48.5	.
2011	11	34.0	34.0	.
2011	12	24.0	24.0	.
2012	1	10.7	16.3	10.7
2012	2	23.7	23.7	.
2012	3	30.5	30.5	.
2012	4	41.3	41.3	.
2012	5	71.8	71.8	.
2012	6	78.3	78.3	.
2012	7	81.5	81.5	.
2012	8	81.9	80.5	81.9
2012	9	77.0	77.0	.
2012	10	48.5	48.5	.
2012	11	34.0	34.0	.
2012	12	24.0	24.0	.
2013	1	10.7	16.3	10.7
2013	2	23.7	23.7	.
2013	3	30.5	30.5	.
2013	4	41.3	41.3	.
2013	5	71.8	71.8	.
2013	6	78.3	78.3	.
2013	7	81.5	81.5	.
2013	8	81.9	80.5	81.9
2013	9	77.0	77.0	.
2013	10	48.5	48.5	.
2013	11	34.0	34.0	.
2013	12	24.0	24.0	.
2014	1	10.7	16.3	10.7
2014	2	23.7	23.7	.
2014	3	30.5	30.5	.
2014	4	41.3	41.3	.
2014	5	71.8	71.8	.
2014	6	78.3	78.3	.
2014	7	81.5	81.5	.
2014	8	81.9	80.5	81.9
2014	9	77.0	77.0	.
2014	10	48.5	48.5	.
2014	11	34.0	34.0	.
2014	12	24.0	24.0	.
2015	1	10.7	16.3	10.7
2015	2	23.7	23.7	.
2015	3	30.5	30.5	.
2015	4	41.3	41.3	.
2015	5	71.8	71.8	.
2015	6	78.3	78.3	.
2015	7	81.5	81.5	.
2015	8	81.9	80.5	81.9
2015	9	77.0	77.0	.
2015	10	48.5	48.5	.
2015	11	34.0	34.0	.
2015	12	24.0	24.0	.
2016	1	10.7	16.3	10.7

KENTUCKY POWER
MW RESIDUALS

YEAR	MONTH	TU_KPC	TUM_KPC	TUS_KPC
2016	2	23.7	23.7	.
2016	3	30.5	30.5	.
2016	4	41.3	41.3	.
2016	5	71.8	71.8	.
2016	6	78.3	78.3	.
2016	7	81.5	81.5	.
2016	8	81.9	80.5	81.9
2016	9	77.0	77.0	.
2016	10	48.5	48.5	.
2016	11	34.0	34.0	.
2016	12	24.0	24.0	.
2017	1	10.7	16.3	10.7
2017	2	23.7	23.7	.
2017	3	30.5	30.5	.
2017	4	41.3	41.3	.
2017	5	71.8	71.8	.
2017	6	78.3	78.3	.
2017	7	81.5	81.5	.
2017	8	81.9	80.5	81.9
2017	9	77.0	77.0	.
2017	10	48.5	48.5	.
2017	11	34.0	34.0	.
2017	12	24.0	24.0	.
2018	1	10.7	16.3	10.7
2018	2	23.7	23.7	.
2018	3	30.5	30.5	.
2018	4	41.3	41.3	.
2018	5	71.8	71.8	.
2018	6	78.3	78.3	.
2018	7	81.5	81.5	.
2018	8	81.9	80.5	81.9
2018	9	77.0	77.0	.
2018	10	48.5	48.5	.
2018	11	34.0	34.0	.
2018	12	24.0	24.0	.
2019	1	10.7	16.3	10.7
2019	2	23.7	23.7	.
2019	3	30.5	30.5	.
2019	4	41.3	41.3	.
2019	5	71.8	71.8	.
2019	6	78.3	78.3	.
2019	7	81.5	81.5	.
2019	8	81.9	80.5	81.9
2019	9	77.0	77.0	.
2019	10	48.5	48.5	.
2019	11	34.0	34.0	.
2019	12	24.0	24.0	.

KENTUCKY POWER
HISTORICAL FITTED AND NORMAL PEAKS

YEAR	MONTH	ACTUAL PEAK	FITTED PEAK	NORMAL SEASONAL PEAK	NORMAL MONTHLY PEAK	ACTUAL TEMPERATURE	MONTHLY REF TEMP
1984	1	1033	973.44	1013.65	994.98	5.0	16.3
1984	2	957	967.77	953.04	953.04	22.5	23.7
1984	3	925	888.36	897.63	897.63	22.5	30.5
1984	4	775	794.09	788.89	788.89	46.0	41.3
1984	5	734	719.20	714.36	714.36	48.5	71.8
1984	6	862	833.25	856.08	822.74	82.5	78.3
1984	7	850	870.94	849.69	849.69	81.5	81.5
1984	8	825	833.18	839.41	839.41	79.0	80.5
1984	9	799	766.10	831.65	831.65	73.5	77.0
1984	10	729	754.20	753.84	753.84	56.5	48.5
1984	11	882	868.66	865.17	865.17	29.0	34.0
1984	12	982	971.23	949.92	949.92	15.0	24.0
1985	1	1026	1070.79	973.46	953.73	-4.0	16.3
1985	2	1009	981.77	985.12	985.12	17.0	23.7
1985	3	852	802.05	890.90	890.90	42.5	30.5
1985	4	831	836.28	799.20	799.20	31.5	41.3
1985	5	732	730.68	716.93	716.93	73.5	71.8
1985	6	780	774.12	816.68	816.68	74.5	78.3
1985	7	850	843.62	878.71	878.71	78.5	81.5
1985	8	881	861.49	903.96	891.03	79.5	80.5
1985	9	832	836.99	792.74	792.74	81.0	77.0
1985	10	739	776.04	747.52	747.52	51.0	48.5
1985	11	746	844.49	761.22	761.22	38.5	34.0
1985	12	1003	971.15	974.81	974.81	16.5	24.0
1986	1	1018	1013.79	1015.24	994.46	10.0	16.3
1986	2	965	995.46	932.30	932.30	15.0	23.7
1986	3	921	935.10	898.14	898.14	24.5	30.5
1986	4	806	819.71	804.95	804.95	41.0	41.3
1986	5	733	745.37	687.54	687.54	76.5	71.8
1986	6	801	802.76	813.94	813.94	77.0	78.3
1986	7	859	868.04	857.67	853.68	82.0	81.5
1986	8	817	852.73	812.33	812.33	81.0	80.5
1986	9	792	784.11	791.64	791.64	77.0	77.0
1986	10	753	746.09	798.55	798.55	63.0	48.5
1986	11	949	920.72	920.16	920.16	26.5	34.0
1986	12	962	940.19	1011.68	1011.68	37.0	24.0
1987	1	1035	1023.16	1045.92	1024.08	13.5	16.3
1987	2	982	953.59	1024.33	1024.33	34.5	23.7
1987	3	900	929.05	893.90	893.90	29.0	30.5
1987	4	882	890.18	848.90	848.90	32.5	41.3
1987	5	842	791.71	795.03	795.03	76.5	71.8
1987	6	852	841.03	870.47	870.47	76.5	78.3
1987	7	931	918.00	939.92	935.80	81.0	81.5
1987	8	926	927.49	895.41	895.41	83.5	80.5
1987	9	809	828.41	834.47	834.47	74.5	77.0
1987	10	874	861.12	839.07	839.07	39.5	48.5
1987	11	912	920.72	925.71	925.71	37.5	34.0
1987	12	965	998.99	973.10	973.10	26.0	24.0
1988	1	1094	1100.68	1078.55	1055.64	7.0	16.3
1988	2	1008	1039.49	1023.93	1023.93	27.5	23.7
1988	3	955	986.79	938.18	938.18	26.5	30.5

SEASONAL REF TEMP: WINTER=10.7 SUMMER=81.9

KENTUCKY POWER
HISTORICAL FITTED AND NORMAL PEAKS

YEAR	MONTH	ACTUAL PEAK	FITTED PEAK	NORMAL SEASONAL PEAK	NORMAL MONTHLY PEAK	ACTUAL TEMPERATURE	MONTHLY REF TEMP
1988	4	853	858.80	869.93	869.93	45.5	41.3
1988	5	790	800.33	778.41	778.41	73.0	71.8
1988	6	913	942.40	852.78	852.78	84.0	78.3
1988	7	967	1009.09	892.51	892.51	88.5	81.5
1988	8	1018	997.55	990.04	975.89	84.5	80.5
1988	9	845	898.26	844.62	844.62	77.0	77.0
1988	10	925	875.04	902.24	902.24	43.0	48.5
1988	11	953	949.41	961.37	961.37	36.0	34.0
1988	12	1069	1052.79	1051.59	1051.59	20.0	24.0
1989	1	1006	1021.50	1071.97	1071.97	31.5	16.3
1989	2	1102	1094.21	1120.55	1064.33	15.0	23.7
1989	3	943	944.86	951.54	951.54	32.5	30.5
1989	4	914	918.68	889.07	889.07	35.5	41.3
1989	5	875	872.37	808.74	808.74	78.0	71.8
1989	6	913	931.88	894.52	894.52	80.0	78.3
1989	7	977	976.39	975.55	971.19	82.0	81.5
1989	8	964	932.67	1002.59	1002.59	77.0	80.5
1989	9	928	925.32	922.14	922.14	77.5	77.0
1989	10	863	899.27	821.04	821.04	39.0	48.5
1989	11	961	959.88	972.14	972.14	36.5	34.0
1989	12	1202	1207.91	1140.12	1080.18	-3.0	24.0
1990	1	1005	1052.10	1082.89	1082.89	33.5	16.3
1990	2	1043	1086.58	1042.24	1042.24	23.5	23.7
1990	3	947	988.59	960.50	960.50	33.5	30.5
1990	4	939	874.56	981.02	981.02	50.5	41.3
1990	5	889	840.50	796.52	796.52	73.0	71.8
1990	6	975	975.08	950.42	950.42	80.5	78.3
1990	7	1049	1033.43	1030.71	1026.23	83.5	81.5
1990	8	1008	999.35	1008.37	1008.37	80.5	80.5
1990	9	1002	987.57	945.35	945.35	82.0	77.0
1990	10	943	894.51	954.92	954.92	51.0	48.5
1990	11	991	1005.93	998.09	998.09	35.5	34.0
1990	12	1051	1013.96	1135.87	1135.87	42.0	24.0
1991	1	1127	1090.99	1210.74	1184.66	28.5	16.3
1991	2	1109	1157.98	1082.20	1082.20	18.0	23.7
1991	3	1020	971.58	1084.72	1084.72	44.0	30.5
1991	4	895	898.94	912.89	912.89	45.0	41.3
1991	5	965	941.37	854.73	854.73	81.5	71.8
1991	6	931	912.77	945.92	945.92	77.0	78.3
1991	7	1062	1036.24	1031.71	1027.10	84.5	81.5
1991	8	1027	992.09	1027.38	1027.38	80.5	80.5
1991	9	1007	987.99	948.81	948.81	82.0	77.0
1991	10	925	919.55	917.72	917.72	47.0	48.5
1991	11	1102	1065.80	1072.53	1072.53	28.0	34.0
1991	12	1150	1123.43	1147.38	1147.38	23.5	24.0
1992	1	1221	1201.10	1229.66	1202.53	12.5	16.3
1992	2	1114	1101.44	1167.65	1167.65	34.5	23.7
1992	3	1081	1101.89	1056.15	1056.15	25.5	30.5
1992	4	1005	1003.66	962.63	962.63	33.0	41.3
1992	5	864	849.91	872.71	872.71	70.5	71.8
1992	6	918	947.19	950.99	950.99	75.5	78.3

SEASONAL REF TEMP: WINTER=10.7 SUMMER=81.9

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KENTUCKY POWER

HISTORICAL FITTED AND NORMAL PEAKS

YEAR	MONTH	ACTUAL PEAK	FITTED PEAK	NORMAL SEASONAL PEAK	NORMAL MONTHLY PEAK	ACTUAL TEMPERATURE	MONTHLY REF TEMP
1992	7	1060	1040.22	1070.23	1065.51	81.0	81.5
1992	8	999	1016.80	1005.31	1005.31	80.0	80.5
1992	9	970	945.10	981.44	981.44	76.0	77.0
1992	10	978	960.58	936.28	936.28	40.5	48.5
1992	11	1091	1030.84	1098.89	1098.89	35.5	34.0
1992	12	1082	1111.77	1119.92	1119.92	31.5	24.0
1993	1	1145	1112.08	1222.62	1222.62	31.5	16.3
1993	2	1228	1197.52	1267.70	1201.59	18.5	23.7
1993	3	1112	1070.82	1122.20	1122.20	32.5	30.5
1993	4	928	944.56	939.88	939.88	45.0	41.3
1993	5	857	905.55	819.07	819.07	75.0	71.8
1993	6	1010	1007.78	1013.63	1013.63	78.0	78.3
1993	7	1106	1085.88	1098.33	1093.48	82.5	81.5
1993	8	1092	1075.41	1068.13	1068.13	82.5	80.5
1993	9	994	1008.04	975.32	975.32	78.5	77.0
1993	10	923	907.26	956.24	956.24	54.5	48.5
1993	11	1071	1057.28	1079.29	1079.29	35.5	34.0
1993	12	1140	1218.52	1095.01	1095.01	15.5	24.0
1994	1	1309	1308.96	1215.25	1186.00	-7.0	16.3
1994	2	1216	1189.57	1212.46	1212.46	23.0	23.7
1994	3	1021	1054.13	1045.66	1045.66	35.0	30.5
1994	4	975	935.12	1018.44	1018.44	49.0	41.3
1994	5	893	911.64	866.38	866.38	74.0	71.8
1994	6	1079	1072.37	1071.15	1026.95	82.5	78.3
1994	7	1052	1053.92	1076.42	1076.42	79.5	81.5
1994	8	1030	1045.51	1061.52	1061.52	78.0	80.5
1994	9	937	999.54	936.55	936.55	77.0	77.0
1994	10	975	958.03	969.43	969.43	47.5	48.5
1994	11	1039	1061.77	1067.99	1067.99	39.0	34.0
1994	12	1157	1140.05	1223.78	1223.78	36.0	24.0
1995	1	1354	1305.10	1330.63	1330.63	12.0	16.3
1995	2	1363	1254.92	1416.66	1345.60	20.5	23.7
1995	3	1091	1129.11	1082.55	1082.55	29.0	30.5
1995	4	981	1006.77	955.59	955.59	37.0	41.3
1995	5	925	975.79	865.96	865.96	76.5	71.8
1995	6	984	1017.34	1013.20	1013.20	76.0	78.3
1995	7	1122	1112.06	1127.94	1127.94	81.0	81.5
1995	8	1136	1136.73	1127.93	1110.93	82.5	80.5
1995	9	964	959.80	1021.02	1021.02	72.5	77.0
1995	10	948	969.59	954.26	954.26	49.5	48.5
1995	11	1089	1116.98	1092.03	1092.03	34.5	34.0
1995	12	1238	1260.12	1229.32	1229.32	22.5	24.0
1996	1	1246	1234.13	1332.36	1332.36	31.5	16.3
1996	2	1418	1374.46	1405.30	1331.78	8.5	23.7
1996	3	1221	1251.22	1135.30	1135.30	15.5	30.5
1996	4	1030	1024.21	1034.32	1034.32	42.0	41.3
1996	5	1042	1039.32	942.52	942.52	79.5	71.8
1996	6	1062	1068.61	1065.90	1065.90	78.0	78.3
1996	7	1041	1075.06	1105.70	1105.70	76.5	81.5
1996	8	1087	1126.09	1111.36	1093.96	80.0	80.5
1996	9	960	1001.44	998.76	998.76	74.0	77.0

SEASONAL REF TEMP: WINTER=10.7 SUMMER=81.9

KENTUCKY POWER
HISTORICAL FITTED AND NORMAL PEAKS

YEAR	MONTH	ACTUAL PEAK	FITTED PEAK	NORMAL SEASONAL PEAK	NORMAL MONTHLY PEAK	ACTUAL TEMPERATURE	MONTHLY REF TEMP
1996	10	885	940.41	938.88	938.88	57.0	48.5
1996	11	1116	1151.23	1106.50	1106.50	32.5	34.0
1996	12	1262	1267.96	1250.10	1250.10	22.0	24.0
1997	1	1417	1381.59	1412.70	1380.28	10.0	16.3
1997	2	1105	1161.03	1176.38	1176.38	35.5	23.7
1997	3	1041	1074.16	1097.03	1097.03	39.5	30.5
1997	4	1088	1082.78	1063.50	1063.50	37.5	41.3
1997	5	932	948.22	934.51	934.51	47.5	71.8
1997	6	1074	1060.44	1097.95	1097.95	76.5	78.3
1997	7	1164	1154.00	1188.88	1183.55	80.0	81.5
1997	8	1084	1129.37	1097.80	1097.80	79.5	80.5
1997	9	1116	1034.34	1142.28	1142.28	75.0	77.0
1997	10	1075	1073.31	1016.00	1016.00	39.5	48.5
1997	11	1237	1185.29	1220.78	1220.78	31.5	34.0
1997	12	1266	1250.91	1314.07	1314.07	32.0	24.0
1998	1	1207	1273.58	1281.03	1281.03	28.5	16.3
1998	2	1095	1157.42	1208.93	1208.93	41.5	23.7
1998	3	1299	1201.28	1391.87	1271.42	26.0	30.5
1998	4	987	992.67	1035.35	1035.35	48.5	41.3
1998	5	1091	1012.03	1074.98	1074.98	73.0	71.8
1998	6	1120	1086.96	1151.30	1151.30	76.0	78.3
1998	7	1178	1191.11	1198.00	1198.00	80.0	81.5
1998	8	1213	1180.53	1238.50	1220.29	80.0	80.5

SEASONAL REF TEMP: WINTER=10.7 SUMMER=81.9

KENTUCKY POWER
FORECAST PEAKS

YEAR	MONTH	FORECAST SEASONAL PEAK	FORECAST MONTHLY PEAK	REF TEMP FOR MONTHLY
1998	9	1110.03	1110.03	77.0
1998	10	1047.05	1047.05	48.5
1998	11	1193.19	1193.19	34.0
1998	12	1320.92	1320.92	24.0
1999	1	1444.31	1388.62	16.3
1999	2	1325.83	1325.83	23.7
1999	3	1208.35	1208.35	30.5
1999	4	1089.01	1089.01	41.3
1999	5	1004.01	1004.01	71.8
1999	6	1147.51	1147.51	78.3
1999	7	1213.94	1213.94	81.5
1999	8	1228.81	1199.27	80.5
1999	9	1121.49	1121.49	77.0
1999	10	1054.69	1054.69	48.5
1999	11	1207.10	1207.10	34.0
1999	12	1334.56	1334.56	24.0
2000	1	1462.68	1405.93	16.3
2000	2	1343.50	1343.50	23.7
2000	3	1233.92	1233.92	30.5
2000	4	1109.34	1109.34	41.3
2000	5	1027.36	1027.36	71.8
2000	6	1168.28	1168.28	78.3
2000	7	1231.99	1231.99	81.5
2000	8	1247.87	1217.93	80.5
2000	9	1141.47	1141.47	77.0
2000	10	1070.49	1070.49	48.5
2000	11	1226.82	1226.82	34.0
2000	12	1356.01	1356.01	24.0
2001	1	1488.30	1430.49	16.3
2001	2	1368.56	1368.56	23.7
2001	3	1250.51	1250.51	30.5
2001	4	1131.74	1131.74	41.3
2001	5	1048.05	1048.05	71.8
2001	6	1189.21	1189.21	78.3
2001	7	1252.25	1252.25	81.5
2001	8	1267.90	1237.55	80.5
2001	9	1160.58	1160.58	77.0
2001	10	1085.97	1085.97	48.5
2001	11	1245.29	1245.29	34.0
2001	12	1376.22	1376.22	24.0
2002	1	1511.87	1453.01	16.3
2002	2	1390.03	1390.03	23.7
2002	3	1279.41	1279.41	30.5
2002	4	1149.80	1149.80	41.3
2002	5	1066.16	1066.16	71.8
2002	6	1209.47	1209.47	78.3
2002	7	1271.85	1271.85	81.5
2002	8	1287.93	1257.18	80.5
2002	9	1180.12	1180.12	77.0
2002	10	1101.57	1101.57	48.5
2002	11	1264.62	1264.62	34.0

SEASONAL REF TEMP: WINTER=10.7 SUMMER=81.9

KENTUCKY POWER
FORECAST PEAKS

YEAR	MONTH	FORECAST SEASONAL PEAK	FORECAST MONTHLY PEAK	REF TEMP FOR MONTHLY
2002	12	1397.65	1397.65	24.0
2003	1	1536.68	1476.76	16.3
2003	2	1412.62	1412.62	23.7
2003	3	1301.25	1301.25	30.5
2003	4	1168.84	1168.84	41.3
2003	5	1085.39	1085.39	71.8
2003	6	1230.69	1230.69	78.3
2003	7	1292.35	1292.35	81.5
2003	8	1308.55	1277.39	80.5
2003	9	1199.93	1199.93	77.0
2003	10	1117.46	1117.46	48.5
2003	11	1284.10	1284.10	34.0
2003	12	1419.16	1419.16	24.0
2004	1	1568.76	1507.78	16.3
2004	2	1439.98	1439.98	23.7
2004	3	1327.34	1327.34	30.5
2004	4	1190.19	1190.19	41.3
2004	5	1107.00	1107.00	71.8
2004	6	1254.66	1254.66	78.3
2004	7	1316.50	1316.50	81.5
2004	8	1332.90	1301.34	80.5
2004	9	1222.18	1222.18	77.0
2004	10	1136.13	1136.13	48.5
2004	11	1307.63	1307.63	34.0
2004	12	1446.80	1446.80	24.0
2005	1	1600.84	1538.81	16.3
2005	2	1467.34	1467.34	23.7
2005	3	1353.44	1353.44	30.5
2005	4	1211.54	1211.54	41.3
2005	5	1128.62	1128.62	71.8
2005	6	1278.63	1278.63	78.3
2005	7	1340.65	1340.65	81.5
2005	8	1357.26	1325.28	80.5
2005	9	1244.43	1244.43	77.0
2005	10	1154.80	1154.80	48.5
2005	11	1331.15	1331.15	34.0
2005	12	1474.43	1474.43	24.0
2006	1	1632.92	1569.83	16.3
2006	2	1494.70	1494.70	23.7
2006	3	1379.53	1379.53	30.5
2006	4	1232.89	1232.89	41.3
2006	5	1150.23	1150.23	71.8
2006	6	1302.60	1302.60	78.3
2006	7	1364.81	1364.81	81.5
2006	8	1381.61	1349.23	80.5
2006	9	1266.69	1266.69	77.0
2006	10	1173.47	1173.47	48.5
2006	11	1354.67	1354.67	34.0
2006	12	1502.07	1502.07	24.0
2007	1	1665.00	1600.85	16.3
2007	2	1522.06	1522.06	23.7

SEASONAL REF TEMP: WINTER=10.7 SUMMER=81.9

KENTUCKY POWER
FORECAST PEAKS

YEAR	MONTH	FORECAST SEASONAL PEAK	FORECAST MONTHLY PEAK	REF TEMP FOR MONTHLY
2007	3	1405.62	1405.62	30.5
2007	4	1254.24	1254.24	41.3
2007	5	1171.84	1171.84	71.8
2007	6	1326.57	1326.57	78.3
2007	7	1388.96	1388.96	81.5
2007	8	1405.96	1373.18	80.5
2007	9	1288.94	1288.94	77.0
2007	10	1192.14	1192.14	48.5
2007	11	1378.19	1378.19	34.0
2007	12	1529.71	1529.71	24.0
2008	1	1697.09	1631.88	16.3
2008	2	1549.43	1549.43	23.7
2008	3	1431.72	1431.72	30.5
2008	4	1275.59	1275.59	41.3
2008	5	1193.45	1193.45	71.8
2008	6	1350.54	1350.54	78.3
2008	7	1413.11	1413.11	81.5
2008	8	1430.32	1397.13	80.5
2008	9	1311.19	1311.19	77.0
2008	10	1210.81	1210.81	48.5
2008	11	1401.72	1401.72	34.0
2008	12	1557.35	1557.35	24.0
2009	1	1729.17	1662.90	16.3
2009	2	1576.79	1576.79	23.7
2009	3	1457.81	1457.81	30.5
2009	4	1296.94	1296.94	41.3
2009	5	1215.06	1215.06	71.8
2009	6	1374.51	1374.51	78.3
2009	7	1437.27	1437.27	81.5
2009	8	1454.67	1421.07	80.5
2009	9	1333.45	1333.45	77.0
2009	10	1229.48	1229.48	48.5
2009	11	1425.24	1425.24	34.0
2009	12	1584.99	1584.99	24.0
2010	1	1761.25	1693.92	16.3
2010	2	1604.15	1604.15	23.7
2010	3	1483.91	1483.91	30.5
2010	4	1318.29	1318.29	41.3
2010	5	1236.67	1236.67	71.8
2010	6	1398.48	1398.48	78.3
2010	7	1461.42	1461.42	81.5
2010	8	1479.02	1445.02	80.5
2010	9	1355.70	1355.70	77.0
2010	10	1248.16	1248.16	48.5
2010	11	1448.76	1448.76	34.0
2010	12	1612.63	1612.63	24.0
2011	1	1793.33	1724.94	16.3
2011	2	1631.51	1631.51	23.7
2011	3	1510.00	1510.00	30.5
2011	4	1339.63	1339.63	41.3
2011	5	1258.28	1258.28	71.8

SEASONAL REF TEMP: WINTER=10.7 SUMMER=81.9

KENTUCKY POWER
FORECAST PEAKS

YEAR	MONTH	FORECAST SEASONAL PEAK	FORECAST MONTHLY PEAK	REF TEMP FOR MONTHLY
2011	6	1422.45	1422.45	78.3
2011	7	1485.57	1485.57	81.5
2011	8	1503.38	1468.97	80.5
2011	9	1377.95	1377.95	77.0
2011	10	1266.83	1266.83	48.5
2011	11	1472.29	1472.29	34.0
2011	12	1640.27	1640.27	24.0
2012	1	1825.41	1755.97	16.3
2012	2	1658.87	1658.87	23.7
2012	3	1536.10	1536.10	30.5
2012	4	1360.98	1360.98	41.3
2012	5	1279.89	1279.89	71.8
2012	6	1446.42	1446.42	78.3
2012	7	1509.73	1509.73	81.5
2012	8	1527.73	1492.91	80.5
2012	9	1400.21	1400.21	77.0
2012	10	1285.50	1285.50	48.5
2012	11	1495.81	1495.81	34.0
2012	12	1667.91	1667.91	24.0
2013	1	1857.49	1786.99	16.3
2013	2	1686.24	1686.24	23.7
2013	3	1562.19	1562.19	30.5
2013	4	1382.33	1382.33	41.3
2013	5	1301.50	1301.50	71.8
2013	6	1470.39	1470.39	78.3
2013	7	1533.88	1533.88	81.5
2013	8	1552.08	1516.86	80.5
2013	9	1422.46	1422.46	77.0
2013	10	1304.17	1304.17	48.5
2013	11	1519.33	1519.33	34.0
2013	12	1695.55	1695.55	24.0
2014	1	1889.57	1818.01	16.3
2014	2	1713.60	1713.60	23.7
2014	3	1588.29	1588.29	30.5
2014	4	1403.60	1403.60	41.3
2014	5	1323.11	1323.11	71.8
2014	6	1494.36	1494.36	78.3
2014	7	1558.03	1558.03	81.5
2014	8	1576.43	1540.81	80.5
2014	9	1444.71	1444.71	77.0
2014	10	1322.84	1322.84	48.5
2014	11	1542.85	1542.85	34.0
2014	12	1723.19	1723.19	24.0
2015	1	1921.65	1849.04	16.3
2015	2	1740.96	1740.96	23.7
2015	3	1614.38	1614.38	30.5
2015	4	1425.03	1425.03	41.3
2015	5	1344.72	1344.72	71.8
2015	6	1518.33	1518.33	78.3
2015	7	1582.19	1582.19	81.5
2015	8	1600.79	1564.76	80.5

SEASONAL REF TEMP: WINTER=10.7 SUMMER=81.9

KENTUCKY POWER
FORECAST PEAKS

YEAR	MONTH	FORECAST SEASONAL PEAK	FORECAST MONTHLY PEAK	REF TEMP FOR MONTHLY
2015	9	1466.97	1466.97	77.0
2015	10	1341.51	1341.51	48.5
2015	11	1566.38	1566.38	34.0
2015	12	1750.83	1750.83	24.0
2016	1	1953.73	1880.06	16.3
2016	2	1768.32	1768.32	23.7
2016	3	1640.47	1640.47	30.5
2016	4	1446.38	1446.38	41.3
2016	5	1366.33	1366.33	71.8
2016	6	1542.30	1542.30	78.3
2016	7	1606.34	1606.34	81.5
2016	8	1625.14	1580.70	80.5
2016	9	1489.22	1489.22	77.0
2016	10	1360.18	1360.18	48.5
2016	11	1589.90	1589.90	34.0
2016	12	1778.47	1778.47	24.0
2017	1	1985.81	1911.08	16.3
2017	2	1795.69	1795.69	23.7
2017	3	1666.57	1666.57	30.5
2017	4	1467.73	1467.73	41.3
2017	5	1387.94	1387.94	71.8
2017	6	1566.27	1566.27	78.3
2017	7	1630.49	1630.49	81.5
2017	8	1649.49	1612.65	80.5
2017	9	1511.47	1511.47	77.0
2017	10	1378.85	1378.85	48.5
2017	11	1613.42	1613.42	34.0
2017	12	1806.11	1806.11	24.0
2018	1	2017.89	1942.10	16.3
2018	2	1823.05	1823.05	23.7
2018	3	1692.66	1692.66	30.5
2018	4	1489.08	1489.08	41.3
2018	5	1409.55	1409.55	71.8
2018	6	1590.24	1590.24	78.3
2018	7	1654.65	1654.65	81.5
2018	8	1673.85	1636.60	80.5
2018	9	1533.73	1533.73	77.0
2018	10	1397.52	1397.52	48.5
2018	11	1636.95	1636.95	34.0
2018	12	1833.75	1833.75	24.0
2019	1	2049.98	1973.13	16.3
2019	2	1850.41	1850.41	23.7
2019	3	1718.76	1718.76	30.5
2019	4	1510.43	1510.43	41.3
2019	5	1431.16	1431.16	71.8
2019	6	1614.21	1614.21	78.3
2019	7	1678.80	1678.80	81.5
2019	8	1698.20	1660.55	80.5
2019	9	1555.98	1555.98	77.0
2019	10	1416.19	1416.19	48.5
2019	11	1660.47	1660.47	34.0

SEASONAL REF TEMP: WINTER=10.7 SUMMER=81.9

KENTUCKY POWER
FORECAST PEAKS

YEAR	MONTH	FORECAST SEASONAL PEAK	FORECAST MONTHLY PEAK	REF TEMP FOR MONTHLY
2019	12	1861.39	1861.39	24.0

SEASONAL REF TEMP: WINTER=10.7 SUMMER=81.9

KENTUCKY POWER
MW RESPONSE TO 1-DEGREE INCREASE IN TEMPERATURE
AT 10-YEAR INTERVALS

TEMPERATURE RANGE	1988	1998	2008
T <= 32	-4.1	-6.1	-8.0
32 < T <= 62	-4.0	-6.6	-9.3
62 < T <= 72	4.3	10.3	16.2
T > 72	10.4	13.5	16.5

STITES & HARBISON

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RECEIVED
JAN 26 2000
PUBLIC SERVICE COMMISSION

January 26, 2000

Mr. Martin Huelsmann
Executive Director
Public Service Commission
730 Schenkel Lane
Frankfort, KY 40601

RE: Case No. 99-437

Dear Mr. Huelsmann:

Please find enclosed and accept for filing an original and six (6) copies of American Electric Power's responses to the Natural Resources and Environmental Protection Cabinet, Division of Energy (KDOE) data requests (1st Set) dated December 20, 1999, in Case No. 99-437.

If you have any questions, please let me know.

Very truly yours,

STITES & HARBISON

Judith Villines

Judith A. Villines

JAV:pjt
Enclosures
cc: Elizabeth E. Blackford, Esq.
Michael L. Kurtz, Esq.
Iris Skidmore, Esq.
Mr. Errol K. Wagner

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING	)	
REPORT OF KENTUCKY POWER COMPANY	)	CASE NO. 99-437
D/B/A AMERICAN ELECTRIC POWER COMPANY	)	

****

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

to

KDOE (1ST SET) DATA REQUESTS
DATED DECEMBER 20, 1999

FILED: JANUARY 26, 2000

INDEX

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING REPORT OF THE KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER TO THE KENTUCKY PUBLIC SERVICE COMMISSION, OCTOBER, 1999	)	CASE NO. 99-437

KENTUCKY DIVISION OF ENERGY'S FIRST REQUEST FOR INFORMATION TO THE KENTUCKY POWER COMPANY

Comes the Natural Resources and Environmental Protection Cabinet, Division of Energy, Intervenor, herein, and makes the following request for information for the purpose of evaluating the effectiveness of the proposed integrated resource plan (IRP):

1. In its February, 1994 report on the 1993 integrated resource plans of the major jurisdictional electric utilities in Kentucky, the staff of the Kentucky Public Service Commission (PSC) noted at page ES-2 that there are two methods of forecasting loads, econometric based load forecasting and end-use forecasting. According to the report, "End use forecasting allows for more explicit treatment of efficiency improvements and relies on explicit forecasts of saturation and unit energy consumption estimates, which can then be used in screening and planning DSM programs." No advantages for econometric based forecasting were cited. In developing its load forecast (1999, Section 2), did the Kentucky Power Company (KPCo) consider using end-use forecasting? Please explain why or why not.

2. On page 2-11, KPCo states that "No explicit adjustments were made to the forecast to account for national appliance efficiency standards or the National Energy Policy Act of 1992." Is this statement equivalent to an assumption that these governmental actions will not affect the trend in energy efficiency one way or the other? Please explain the response. If KPCo *had* decided to make explicit adjustments to account for these governmental actions, how would the adjustments have been applied to the model?

3. In developing its IRP, did KPCo perform a study to estimate the total quantity of demand-side energy efficiency and load shifting measures that would be available within its service area (i.e., a technical potential study), the cost of implementing such measures, and the revenue requirements that would be needed to acquire various portions of these potential resources through DSM programs?

4. Did KPCo estimate the square footage of residential, commercial, and industrial floor space that is being newly constructed each year in its service area? If so, what are the estimated square footage figures?

5. Did KPCo survey the energy efficiency of the new buildings being constructed in its service area? If so, please provide the results of this analysis.

6. Has KPCo availed itself of information from organizations such as E-Source, which is a source of comprehensive information on energy efficiency technologies and programs? To what extent, if any, was information from such sources used in developing the IRP?

7. On page 3-2, the IRP notes, "Increasing appliance efficiency standards and years of customer educational programs will make energy efficiency the normal practice in the future." A similar statement is made on page 3-5.

a. Please describe the scope of these customer education programs, as well as any estimates that KPCo may have made of their impacts on customers' behavior and on energy use.

b. Does KPCo believe that the normal operation of market forces (i.e., Adam Smith's "Invisible Hand") will cause customers to implement all energy efficiency measures that are cost effective?

c. Does KPCo believe there are significant market barriers that act to prevent customers from implementing all the energy efficiency measures that would be cost effective?

8. When was the last time AEP performed an extensive analysis on a wide range of DSM options, or measures, as discussed in the second paragraph of Section D on page 3-5? Were the results of this analysis shared with the KPCo DSM Collaborative?

9. The next paragraph on page 3-5 states that "In the case of KPCo, the DSM Collaborative, since its inception in November 1994, has been the decision-maker on the program screening process." A similar statement is made on page 3-6: "In this regard, the Collaborative continues to be the decision-maker on the DSM program-screening process and governs which DSM programs are to be screened for potential implementation in KPCo's service territory."

a. Aside from the Collaborative, which other organizational units or employees, if any, within KPCo or AEP have been assigned to develop new DSM program ideas for the KPCo service territory?

b. Did KPCo ever inform the DSM Collaborative that the Collaborative was the decision-maker on the program screening process? If so, approximately when?

c. Did KPCo ever describe to the DSM Collaborative just what tasks and responsibilities go along with being the decision-maker on the program screening process? If so, approximately when?

d. What resources, if any, has KPCo made available to the Collaborative to enable the Collaborative to carry out its responsibiiities as the decision-maker on the program screening process? [for example, budget to develop new DSM program ideas, access to expert consultants, training, etc.]

e. To what degree has KPCo been open to suggestions for new DSM programs brought up by members of the Collaborative?

10. Whose conclusion was it that "in anticipation of deregulation, the emphasis of the DSM evaluation process has been shifted from a societal perspective, as reflected in the Total Resource Cost (TRC) test, to the ratepayer perspective, as reflected in the Ratepayer Impact Measure (RIM) test" [page 3-5], the Collaborative's or KPCo's? If it was a conclusion of the Collaborative, please provide a copy of the minutes of the meeting where this conclusion was reached.

11. Please describe in more detail how "the uncertainties regarding (a) customer choice of energy supplier in the future and (b) DSM cost-recovery mechanisms in the AEP System's different state jurisdictions serve to hinder the effectiveness and meaningfulness of the DSM evaluation process" [page 3-6].

12. On page 3-6, the IRP states that "The Collaborative has re-screened and re-evaluated the DSM programs originally filed for approval with the Commission in September 1995 and implemented in January 1996."

a. What does the word "re-screened" mean in this context? Does it mean anything more than "re-evaluated"?

b. Has KPCo ever asked the Collaborative to screen "a wide range of DSM options or measures", other than these existing programs? If so, please provide the approximate dates, and the "long list" of DSM options and measures considered.

13. When deciding on the set of DSM programs to recommend for implementation, did KPCo consider "the extent to which the plan provides programs which are available, affordable, and useful to all customers" [Reference KRS 278.285 (1)(g)]? Please discuss the degree to which the set of recommended DSM programs meets this statutory criterion.

14. Exhibit 3-3 projects that DSM impacts will level off and then decline over time. Has KPCo considered the possibility that technological advances in demand-side technology will continue to open new opportunities for cost-effective energy efficiency improvements?

15. The method of local integrated resource planning (LIRP), as described in a strategic issues paper by E-Source (1995) titled, "Local Integrated Resource Planning: A New Tool for a Competitive Era," is designed to determine if costs could be reduced by deferring transmission and distribution upgrades through the use of geographically-focused demand-side programs. [Other names for LIRP include "targeted area planning," "local area

investment planning," "distributed resources planning," or "area wide asset and customer service."]

a. Did KPCo use the LIRP approach to determine whether any planned transmission or distribution projects could economically be deferred? If so, please provide the results of the studies.

b. Does KPCo plan to use the LIRP approach in the future?

16. Please provide a detailed description of the method KPCo uses to determine how much to charge a new residential, commercial, or industrial customer to hook up their building to the grid. Please explain why this particular method or formula was chosen.

17. Did KPCo evaluate the cofiring of coal with sawdust at low percentages (e.g., less than 2 or 3 percent sawdust by weight) at existing coal-fired plants, which would provide a valuable service for the sawmill operations located in or near KPCo' service territory and also would reduce SO_2 emissions? Please explain the response.

Respectfully submitted,

Ronald P. Mills

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Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, Kentucky 40601
Telephone: (502) 564-6676

COUNSEL FOR NATURAL RESOURCES
AND ENVIRONMENTAL PROTECTION

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Request for Information, First Set
Dated December 20, 1999

Request No. 1:

In its February, 1994 report on the 1993 integrated resource plans of the major jurisdictional electric utilities in Kentucky, the staff of the Kentucky Public Service Commission (PSC) noted at page ES-2 that there are two methods of forecasting loads, econometric based load forecasting and end-use forecasting. According to the report, "End use forecasting allows for more explicit treatment of efficiency improvements and relies on explicit forecasts of saturation and unit energy consumption estimates, which can then be used in screening and planning DSM programs." No advantages for econometric based forecasting were cited. In developing its load forecast (1999, Section 2), did the Kentucky Power Company consider using end-use forecasting? Please explain why or why not.

Response:

The Company's position with respect to the relative merits of end-use and econometric forecasting was set forth in a response to an information request from the Kentucky Public Service Commission Staff with respect to the Company's 1996 IRP Report to the Commission (Case No. 96-495). The Staff's request (No. 8, First Set, Dated December 13, 1996) and the Company's response are repeated below.

Request No. 8:
Refer to page 2-2. Kentucky Power states that residential energy sales are now forecasted using econometric time-series models, rather than an end-use model. In Kentucky Power's 1993 IRP (Case No. 93-347, A Review Pursuant to 807 KAR 5:058 of the 1993 Integrated Resource Plan of Kentucky Power Company), at page III-2, it is stated that, "End use analysis offers the advantage that the sources of load may be studied in great detail, so that the potential impacts of price, income, technology, and other changes may be analyzed more precisely." Explain what has occurred since 1993 to necessitate the change of residential energy sales forecasting methodology by Kentucky Power.

Response:
This issue is addressed on pages 2-16 and 2-17 (in Section I.3, Forecasting Methodology) of KPCo's 1996 IRP report. Additional discussion on this subject follows.

Request No. 1

Response (cont'd)

The potential impacts of price, income, technology and other changes may indeed be analyzed more precisely by end-use models than by econometric time-series models of aggregate residential energy consumption. However, it is also true, as stated on the same page as that referenced in this request (i.e., p. III-2 of KPCo's 1993 IRP report), that:

> "Econometric analysis of time-series data provides a relatively efficient means of producing an internally consistent forecast using the information available. The econometric models can be adjusted to reflect the occurrence of new events or situations that point to changes in the economic, demographic, and meteorological factors that influence load. Econometric analysis of time-series data permits the assumptions that underlie the forecast and the effects of the various forces affecting the load to be quantified."

While end-use models are useful for projecting the consumption of specific end-use constituents of residential load (this is the sense in which they are more precise than econometric time-series models), these models require large amounts of household-specific data, which are expensive to obtain. Also, because they are structurally complex, end-use models consume considerably more labor and computational resources in their development than do econometric time-series models. These expenses are recurrent, and as time passes, the models need to be updated and re-specified with new data. If end-use-specific load projections are not extremely useful, the extra expense involved in developing and maintaining end-use models may not be warranted from the viewpoint of the economical use of forecasting resources.

The company's interest in end-use-specific projections of residential consumption has diminished since the early 1990s, and the uses of the load forecast have increasingly focused on aggregate load (or aggregate loads of entire customer classes). As a result, the company's methods of producing load forecasts have, for efficiency's sake, shifted away from end-use models and toward econometric analyses of load on an aggregate-class basis.

Respondent: N. Tibberts

2

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Request for Information, First Set
Dated December 20, 1999

Request No. 2:

On page 2-11, KPCo states that "No explicit adjustments were made to the forecast to account for national appliance efficiency standards or the National Energy Policy Act of 1992." Is this statement equivalent to an assumption that these governmental actions will not affect the trend in energy efficiency one way or the other? Please explain the response. If KPCo had decided to make explicit adjustments to account for these governmental actions, how would the adjustments have been applied to the model?

Response:

The cited statement is not equivalent to assuming that the National Energy Policy Act of 1992 will not affect energy usage. It does imply that the Company believes that any effects of the Act not already reflected in the econometric results are likely to be small in relation to other possible sources of forecast inaccuracy. As observed in the Company's discussion of conservation effects on pages 2-10 and 2-11 of the IRP Report, energy efficiency has been increasing since the energy price crisis of the mid-1970s, and this has reduced the rate of growth of energy usage during the period over which the forecast models are estimated. This effect, of which the Act can be seen as a continuation, is already roughly reflected in the forecast results.

Had the Company decided to make explicit adjustments to reflect the effects, if any, of the Act beyond that already reflected in the model results, adjustments would most likely have been applied by subtracting from, or adding to, the load levels predicted by the models.

Respondent: N. Tibberts

3

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Request for Information, First Set
Dated December 20, 1999

Request No. 3:

In developing its IRP, did KPCo perform a study to estimate the total quantity of demand-side energy efficiency and load-shifting measures that would be available within its service area (i.e., a technical potential study), the cost of implementing such measures, and the revenue requirements that would be needed to acquire various portions of these potential resources through DSM programs?

Response:

AEP did perform a study, as part of the integrated resource planning process, to estimate the total quantity of demand-side management (DSM) measures that would be available within the AEP service territory. A list of DSM measures, each identified by load objective (i.e., strategic conservation, load shifting, or peak clipping) was provided in Exhibit 3-3 of KPCo's 1996 IRP Report to the Commission. The study included various parameters relating to the costs and benefits associated with implementing each DSM measure and its technical and market potential.

Respondent: N. Tibberts

4

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Request for Information, First Set
Dated December 20, 1999

Request No. 4:

Did KPCo estimate the square footage of residential, commercial, and industrial floor space that is being newly constructed each year in its service area? If so, what are the estimated square footage figures?

Response:

The Company has made no such estimate.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Request for Information, First Set
Dated December 20, 1999

Request No. 5:

Did KPCo survey the energy efficiency of new buildings being constructed in its service area? If so, please provide the results of this analysis.

Response:

The Company has conducted no such survey.

Respondent: N. Tibberts

9

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Request for Information, First Set
Dated December 20, 1999

Request No. 6:

Has KPCo availed itself of information from organizations such as E-Source, which is a source of comprehensive information on energy efficiency technologies and programs? To what extent, if any, was information from such sources used in developing the IRP?

Response:

Yes; AEP has subscribed to E-Source and used E-Source's comprehensive information on energy efficiency technologies and programs in developing its integrated resource plan. Additionally, as noted on page 3-7 (under F.1. Overview) of KPCo's 1996 IRP Report to the Commission, AEP has used numerous sources, both internal and external to the Company, as part of the overall DSM analysis procedure. These sources were used to develop an initial list of DSM measures for the screening process, along with detailed information on various parameters of the DSM measures, in order to perform cost-benefit analyses. Also, subsequent screenings and evaluations were performed on DSM measures based on updated information obtained from these sources and actual program field data.

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Request for Information, First Set
Dated December 20, 1999

Request No. 7:

On page 3-2, the IRP notes, "Increasing appliance efficiency standards and years of consumer educational programs will make energy efficiency the normal practice in the future." A similar statement is made on page 3-5.

a. Please describe the scope of these customer education programs, as well as any estimates that KPCo may have made of their impacts on customers' behavior and on energy use.

b. Does KPCo believe that the normal operation of market forces (i.e., Adam Smith's "Invisible Hand") will cause customers to implement all energy efficiency measures that are cost effective?

c. Does KPCo believe that there are significant barriers that act to prevent customers from implementing all the energy efficiency measures that would be cost effective?

Response:

To begin with, the statement referenced on page 3-2 of KPCo's IRP Report relates to the continuation of the federal government-implemented Energy Efficiency & Appliance Standards and of customer education programs provided by federal and local government agencies, professional trade organizations, public interest groups and energy services companies, as well as local utility companies.

To elaborate further, the Federal Energy Efficiency & Appliance Standards were established by the U.S. Congress through the 1987 National Appliance Energy Conservation Act & 1988 Amendments, and the 1992 National Energy Policy Act. These standards are continuing to be upgraded and expanded, with the next set of new efficiency standards scheduled to be in place in October 2000 for room air conditioners, and in July 2001 for refrigerators. Additionally, the U.S. Department of Energy has proposed to increase efficiency standards for central air conditioners and heat pumps, and to implement a final ruling on such standards by December 2000. The continuation of these federally mandated standards for product manufacturers will provide consumers with the availability of high-efficiency products such as household appliances, heating and cooling systems, lighting, plumbing products and water heaters, thus enhancing the use of high-efficiency products in the home.

Request No. 7

Response (cont'd)

a. Customer education programs on energy efficiency are available to consumers today through many sources. Examples of such education programs follow.

Energy Star, a partnership between the U.S. Department of Energy (DOE) and the U.S. Environmental Protection Agency, promotes energy-efficient products from all major manufacturers, by labeling such products with the Energy Star label and educating consumers about the benefits of energy efficiency. Products having the Energy Star label include various household appliances, home electronics equipment (TVs, VCRs, home audio, computers, printers, etc.), heating and cooling systems, residential lighting fixtures, windows, roofing material and home insulation.

The Federal Trade Commission's Appliance Labeling Rule requires that EnergyGuide labels be placed on all new refrigerators, freezers, water heaters, dishwashers, clothes washers, room air conditioners, central air conditioners, heat pumps, furnaces and boilers. EnergyGuide labels identify energy consumption characteristics of household appliances, thus allowing the consumer the opportunity to compare annual energy consumption and operating costs of similar appliance models.

The DOE also provides a wealth of information on energy-efficient products through programs such as the Federal Energy Management Program and the Energy Efficiency and Renewable Energy Network. Numerous publications on energy-efficient products are provided to consumers by various professional trade organizations and public interest groups, such as: American Council for an Energy-Efficient Economy (ACEEE), Air Conditioning Refrigeration Institute (ARI), Association of Home Appliance Manufacturers (AHAM), Consortium for Energy Efficiency, Edison Electric Institute (EEI), and Gas Appliance Manufacturers Association. Home building suppliers, such as Lowe's and 84 Lumber, provide brochures on energy-efficient products and construction practices for both contractors and do-it-yourself home builders. Also, aside from utility-sponsored DSM education programs, energy service companies have provided energy product and service information to customers.

In addition to the numerous education programs that are provided to consumers by federal and local government agencies, professional trade organizations, public interest groups and energy services companies, KPCo has incorporated customer education in its DSM programs and provides pertinent information via monthly bill inserts. No estimates have been made of the impacts of KPCo's customer education programs on customer energy use.

Customer education information was also developed by the KPCo DSM Collaborative (which includes a KDOE representative) in conjunction with several DSM programs. A description of the type of information provided with each of these programs follows.

Request No. 7

Response (cont'd)

It should be recognized that the implementation of cost-effective energy efficiency measures is not necessarily determined or performed solely by the customer, but rather through other mechanisms, such as mandated Federal Energy Efficiency & Appliance Standards, the establishment of upgraded home building codes, and the availability of energy-efficient products to building, plumbing, electrical and HVAC contractors. Additionally, the promotion of energy efficiency measures through entities such as professional trade organizations, public interest groups and energy services companies encourages customers to implement such measures.

c. Based on the availability of energy efficiency measures on the market today for both contractors and consumers, along with improved Federal Energy Efficiency & Appliance Standards and upgraded home building codes, the Company believes that many of the significant market barriers that may have prevented the implementation of cost-effective energy efficiency measures, such as product or service unavailability, unreliable information, uncertainty of product performance, long payback periods and access to financing, are being overcome. Energy efficiency measures have become established standards for both product manufacturers and building contractors. Additionally, energy efficiency measures will continue to be instituted by government agencies and product manufacturers in the future, along with energy efficiency services and products provided by energy service companies, to promote and establish energy efficiency according to the customer's needs and lifestyle.

Request No. 7

Response (cont'd)

- The Energy Fitness Program provided to participating customers an educational booklet and an AEP "SMART Energy Savings Tips" video. These educational sources discussed simple energy-saving measures that homeowners could perform to reduce their overall energy consumption. The measures discussed in the booklet and video were in addition to those measures provided and installed in the Energy Fitness Program.

- The Targeted Energy Efficiency Program provides an educational booklet to participating customers. The weatherization staff representatives who conduct the audit discuss with the homeowner the energy-saving measures contained in the booklet, along with the benefits attributable to the installation of the energy conservation measures in the customer's home.

- The Mobile Home New Construction Program is promoted by participating mobile home dealers. The dealers promote high-efficiency heat pumps and provide a "flyer" to each potential participant, explaining the benefits and the potential energy savings associated with the installation of a zone-3 insulation package and a high-efficiency heat pump in a new mobile home.

- The Commercial SMART Audit Program provides an audit report on each participant's facility. The report describes in detail the conditions found at the time the audit was conducted and the recommended energy-saving measures to be installed at the facility. The Class I Audits (less than 100 kW) are mailed to each program participant, and the Class II Audits (at least 100 kW) are delivered to the customer personally by the Company's business services representative or Efficiency Services Supervisor.

The Company also provides bill insert information through its "Consumer Circuit" Program, which includes literature with the monthly bills to all residential customers. The literature explains the benefits of implementing various energy-efficiency measures in the home. Examples of some of the topics included are: NEED Project Education On Energy, Tips For Conserving Electricity, The Heat Pump: A Smart Choice, Efficient Lighting Makes Environmental Sense, Plant Trees To Reduce Your Electricity Usage, Need An Energy-Efficient Water Heater Fast?, and Prepare Now For A Cozy Winter.

b. No; the notion that the normal operation of market forces or Adam Smith's "Invisible Hand" will cause customers to implement all energy efficiency measures that are cost-effective is incongruous and vague; it does not consider energy efficiency measures already in place today, nor the additional non-marketing factors contributing to the establishment of energy efficiency measures in a customer's lifestyle.

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d/b/a AMERICAN ELECTRIC POWER
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Dated December 20, 1999

Request No. 8:

When was the last time that AEP performed an extensive analysis on a wide range of DSM options, or measures, as discussed in the second paragraph of Section D on page 3-5? Were the results of this analysis shared with the KPCo DSM Collaborative?

Response:

Extensive analyses were performed on a wide range of DSM options and measures from an AEP perspective in 1994, with additional analyses performed in 1995 and 1996 on those options or measures having significant modifications. The results of the analyses, which included a list of potential DSM programs for implementation, were shared with the KPCo DSM Collaborative and used in the selection process of DSM programs considered for KPCo.

Also, extensive analyses of KPCo's DSM programs are routinely performed and shared with the Collaborative. The most recent such analysis was performed in 1999, the results of which are included in Chapter 3 of the KPCo IRP Report.

Respondent: N. Tibberts

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Dated December 20, 1999

Request No. 9:

The next paragraph on page 3-5 states that "In the case of KPCo, the DSM Collaborative, since its inception in 1994, has been the decision-maker on the program-screening process." A similar statement is made on page 3-6: "In this regard, the Collaborative continues to be the decision-maker on the DSM program-screening process and governs which DSM programs are to be screened for potential implementation in KPCo's service territory."

a. Aside from the Collaborative, which other organizational units or employees, if any, within KPCo or AEP have been assigned to develop new DSM program ideas for the KPCo service territory?

b. Did KPCo ever inform the DSM Collaborative that the Collaborative was the decision-maker on the program screening process? If so, approximately when?

c. Did KPCo ever describe to the DSM Collaborative just what tasks and responsibilities go along with being the decision-maker on the program-screening process? If so, approximately when?

d. What resources, if any, has KPCo made available to the Collaborative to enable the Collaborative to carry out its responsibilities as the decision-maker on the program screening process? [for example, budget to develop new program ideas, access to expert consultants, training, etc.]

e. To what degree has KPCo been open to new suggestions for new DSM programs brought up by members of the Collaborative?

Response:

a. In the past, AEP's Demand-Side Management Planning & Analysis group (currently Load Research & Analysis Services), in conjunction with AEP/KPCo Consumer Services, has been responsible for developing new DSM program ideas for the KPCo service territory. Currently, no other organizational units or employees within KPCo or AEP have been assigned to develop such new DSM program ideas. Moreover, the Collaborative has already developed a package of DSM programs that have been successful and has requested Commission approval for a three-year extension of the proposed DSM Plan filed with the Commission on August 13, 1999.

Request No. 9

Response (cont'd)

b. Yes. One of the main objectives of the KPCo DSM Collaborative, as discussed at its initial/organizational meeting, held on November 14, 1994, is to develop DSM programs for KPCo, which would involve the screening of DSM programs suggested by various Collaborative members, including AEP/KPCo. At that meeting, Collaborative members were asked to determine what DSM programs should be considered in order to provide effective DSM programs for all classes of KPCo customers.

c. Yes. The tasks and responsibilities associated with screening DSM programs and determining which programs are to be implemented in KPCo were discussed at the Collaborative's organizational meeting, held on November 14, 1994. Some of these tasks and responsibilities are briefly outlined in the KPCo By-laws of the DSM Collaborative, as developed in Collaborative meetings that followed the organizational meeting. Additionally, AEP has described to the Collaborative the program-screening process previously implemented for the AEP System.

d. Resources have been made available, through both KPCo and the DSM Collaborative, to enable the Collaborative to carry out its responsibilities with respect to the screening of DSM programs. In this regard, various members of the DSM Collaborative, with Staff support from KPCo/AEP, have provided backgrounds essential for screening and developing appropriate DSM programs for the residential, commercial and industrial sectors. In addition, the Office of the Kentucky Attorney General hired an expert consultant to participate in the DSM Collaborative and thereby provide insight into the screening and design of the DSM programs. Also, a budget was established by the Collaborative to research and design a potential Mobile Home New Construction Program, which was expanded from an educational program into a full-scale implementation program.

Furthermore, an outside consultant, who was initially hired to assist in the development and evaluation of the Targeted Energy Efficiency Program, provided suggestions for improving the administration of the program and for screening and targeting participants to improve the program's cost-effectiveness. In this regard, program screening relates not only to which DSM programs should be implemented at the onset, but also to how DSM programs already in place can be improved by monitoring their progress. Such concepts are part of the Collaborative's re-screening and re-evaluating process, which is explained on page 3-6 of the IRP Report.

e. KPCo/AEP has been open to considering new suggestions for new DSM programs since the inception of the DSM Collaborative in November 1994. In fact, the Mobile Home New Construction Program, which was developed as an educational program and later expanded to a full-scale implementation program, was initially suggested by the KDOE representative. Additionally, new measures and program modifications suggested by Collaborative members have been reviewed for inclusion in the Commercial SMART Financing Program and the Targeted Energy Efficiency Program.

Respondent: N. Tibberts

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d/b/a AMERICAN ELECTRIC POWER
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Request No. 10:

Whose conclusion was it that "in anticipation of deregulation, the emphasis of the DSM evaluation process has been shifted from a societal perspective, as reflected in the Total Resource Cost (TRC) test, to the ratepayer perspective, as reflected in the Ratepayer Impact Measure (RIM) test" [page 3-5], the Collaborative's or KPCo's? If it was a conclusion of the Collaborative, please provide a copy of the minutes of the meeting where this conclusion was reached.

Response:

Neither the Collaborative nor KPCo made this "conclusion." The observation given on page 3-5 of the KPCo IRP Report, i.e., that the emphasis of the DSM evaluation process has been shifted from the societal perspective to the ratepayer perspective in anticipation of deregulation, reflects how AEP has evaluated DSM programs. It also reflects a trend in how utilities have generally been viewing DSM in the context of the movement of the industry to a competitive retail environment.

Currently, the DSM evaluation process used for the KPCo DSM Collaborative is based on applying all four traditional economic tests, i.e., the TRC, RIM, UC and P tests, as noted on pages 3-6 and 3-7 of the Report. The Company has no immediate plans to change this evaluation process for the KPCo DSM programs.

Respondent: N. Tibberts

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Dated December 20, 1999

Request No. 11:

Please describe in more detail how "the uncertainties regarding (a) customer choice of energy supplier in the future and (b) DSM cost-recovery mechanisms in the AEP System's different state jurisdictions serve to hinder the effectiveness and meaningfulness of the DSM evaluation process" [page 3-6].

Response:

In the future competitive environment, which will feature customer choice, it is anticipated that there will be many new energy suppliers and new customer types that will enter the market. In that market, many customers may frequently switch energy suppliers. The uncertainties associated with customer choice relate to pertinent issues/questions that must be addressed, such as: (a) Who are the new players, i.e., the energy suppliers, as well as the customers? (b) What are the energy suppliers' planning criteria for providing energy efficiency services for both full-service customers and "wires-only" service customers? and (c) What are each type of customer's energy efficiency needs in the competitive open market?

Such uncertainties hinder the effectiveness and meaningfulness of the current DSM evaluation process for the local utilities because the actual benefits and costs associated with the DSM programs that may be offered will not only be difficult to establish, but may also be ever-changing, as a result of continual changes in the utility's customer base (both full-service and wires-only service) and associated load characteristics.

Also, in the competitive market, a timely DSM cost-recovery mechanism, such as the surcharge method utilized by KPCo, is becoming more important, if not necessary, for making a DSM program viable. As the utility customer base may continually change in the future competitive market, a deferred-payment type of cost-recovery mechanism, which is embedded in the rate base (as is the case in some AEP operating company jurisdictions), simply creates a higher level of business risk for the utility. Under such conditions, the DSM evaluation process may not provide realistic results, thus hindering the effectiveness and meaningfulness of that process.

Respondent: N. Tibberts

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Request No. 12:

On page 3-6, the IRP states that "The Collaborative has re-screened and re-evaluated the DSM programs originally filed for approval with the Commission in September 1995 and implemented in January 1996."

a. What does the word "re-screened" mean in this context? Does it mean anything more than "re-evaluated"?

b. Has KPCo ever asked the Collaborative to screen "a wide range of DSM options or measures," other than these existing programs? If so, please provide the approximate dates, and the "long list" of DSM options and measures considered.

Response:

a. The word "re-screen" refers to reviewing the DSM programs that are already in place to determine if the programs are still suitable for continued implementation and are beneficial to the customers. For example, as noted on pages 3-2 (first full paragraph) and 3-6 (third full paragraph) of the IRP Report, the Compact Fluorescent Lighting Program was discontinued at year-end 1996 as a result of decreased customer acceptance of the program, as evidenced by the reduced customer participation levels. After reviewing this program, the Collaborative concluded that offering this program was no longer beneficial to KPCo's residential customers.

The word "re-evaluate" refers to estimating the net worth or value of the DSM program, which is determined by the program's cost-effectiveness based on updated information obtained since the program's initial implementation. For example, as noted on pages 3-2 (first full paragraph) and 3-6 (third full paragraph), the Energy Fitness Program was discontinued in May 1999, not only because of reduced participation levels, but because of the increased promotional and installation costs, which, along with reduced anticipated load impacts, reduced the cost-effectiveness of the program.

Request No. 12

Response (cont'd)

b. KPCo did ask the Collaborative to screen DSM options or measures, as indicated in the Response to Request No. 9, this set. Although the number of measures screened by the Collaborative may not meet KDOE's definition of a "wide range" or "long list" of measures, the list initially included measures in addition to those in the KPCo DSM Collaborative programs.

An initial list of DSM measures was provided by Collaborative members (including those measures provided by the KDOE representative) in the Collaborative's third meeting, which was held on January 18, 1995. The list was attached to that meeting's minutes, a copy of which the KDOE representative should have in his possession.

Respondent: N. Tibberts

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Request No. 13:

When deciding on the set of DSM programs to recommend for implementation, did KPCo consider "the extent to which the plan provides programs which are available, affordable, and useful to all customers" [Reference KRS 278.285 (1)(g)]? Please discuss the degree to which the set of recommended DSM programs meets this statutory criterion.

Response:

Yes; the KPCo DSM Collaborative, which includes a KDOE representative, did consider "the extent to which the plan provides programs which are available, affordable, and useful to all customers." As indicated in the Response to Request No. 9.b, this set, Collaborative members were specifically asked to consider DSM programs for all classes of KPCo customers.

With respect to the residential customer class, the KPCo DSM Collaborative plan has included six residential DSM programs that collectively targeted all segments of residential customers. These programs are: the Compact Fluorescent Bulb Program, Energy Fitness Program, Targeted Energy Efficiency Program, High-Efficiency Heat Pump Program, High-Efficiency Heat Pump-Mobile Home Program, and the Mobile Home New Construction Program. These programs' target customers have ranged from all residential customers to those residential customers having electric space and water heating, and have specifically included low-income customers. The measures provided in these programs were established energy efficiency measures that have been implemented by other utilities across the country, and proven to be useful to residential customers.

Also, for the Energy Fitness and Targeted Energy Efficiency programs, the energy efficiency measures have been offered at no charge to customers. For the other programs, i.e., the Compact Fluorescent Bulb, High-Efficiency Heat Pump, Heat-Efficiency Heat Pump-Mobile Home and New Mobile Home Construction programs, such measures have been offered with an incentive, to offset the cost of the measures.

Thus, the residential DSM programs have met the statutory criterion of providing programs which are available, affordable and useful to all customers.

Request No. 13

Response (cont'd)

With respect to the commercial and industrial customer classes, the KPCo DSM Collaborative plan has included various measures in the Commercial & Industrial SMART Audit and SMART Financing programs, available to all customers in these classes. Such measures, which are described in the KPCo DSM Collaborative Program filed with the Commission on September 27, 1995, included established DSM measures that have been implemented by other utilities across the country, and proven to be useful to customers in these classes.

Also, the SMART Audit Program offered Class I Audits at no charge to qualified customers, and Class II Audits at minimal cost to qualified customers. The SMART Financing Program provided the customers with assistance through financial incentives, to offset part of the cost of the energy-efficient measures installed at the customer's facility. Thus, through the use of no-cost/low-cost audits and financial incentives provided by KPCo to assist the customers in installing energy-efficient measures, the SMART Audit and SMART Financing programs met the statutory criterion of affordability, in addition to availability and usefulness.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
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Request No. 14:

Exhibit 3-3 projects that DSM impacts will level off and then decline over time. Has KPCo considered the possibility that technological advances in demand-side technology will continue to open new opportunities for cost-effective energy efficiency improvements?

Response:

Yes; AEP/KPCo has considered the possibility of future advances in demand-side technology. However, to the extent that sufficient information on such advances is not available, their system impacts can not be determined with confidence and effectively incorporated into the integrated resource planning process. In this regard, it should be noted that the DSM impacts shown in Exhibit 3-3 of the IRP Report are those associated with KPCo's currently established DSM programs and do not incorporate unforeseen additional DSM programs that may be offered, including those that reflect advances in demand-side technology.

It should also be noted, as mentioned in the Response to Request No. 7, this set, that the continuing upgrades in the Federal Energy Efficiency & Appliance Standards and in home building codes have incorporated technological advances in demand-side technology, and will continue to do so in the future. Many, if not all, of the increased efficiency standards are a direct result of improved technological advances in the appliances offered by product manufacturers today. For example, the Company's High-Efficiency Heat Pump and High-Efficiency Heat Pump-Mobile Home programs, along with the New Mobile Home Construction Program, promote the advanced technology that has been developed for high-efficiency and ultra-high-efficiency heat pumps available on the market today and also the improved building codes for mobile homes.

Respondent: N. Tibberts

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KPSC Case No. 99-437
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Dated December 20, 1999

Request No. 15:

The method of local integrated resource planning (LIRP), as described in a strategic issues paper by E-Source (1995) titled, "Local Integrated Resource Planning: A New Tool for a Competitive Era," is designed to determine if costs could be reduced by deferring transmission and distribution upgrades through the use of geographically-focused demand-side programs. [Other names for LIRP include "targeted area planning," "local area investment planning," "distributed resources planning," or "area wide asset and customer service."]

a) Did KPCo use the LIRP approach to determine whether any planned transmission or distribution projects could economically be deferred? If so, please provide the results of the studies.

b) Does KPCo plan to use the LIRP approach in the future?

Response:

AEP/KPCo's approach to meeting anticipated customer needs for the future, i.e., planning and implementing appropriate measures to accommodate those needs, necessarily encompasses a variety of perspectives. One of these, the system-wide perspective, considers the needs of the overall AEP System, which is planned and operated on a wholly integrated basis, in the context of operating as part of an interconnected, multi-state regional grid. More localized perspectives focus on geographic portions of the System, including particular transmission or distribution areas.

Whether planning on a system-wide basis or on a more local basis, however, AEP applies integrated resource planning concepts, i.e., both supply-side and demand-side measures are considered to the extent such measures are feasible and cost-effective. In this regard, the cost-benefit analyses of DSM programs take into consideration the avoided costs associated with the deferral of additional transmission and distribution facilities, as well as the deferral of additional generation facilities, as indicated on page 3-7 (first full paragraph) of the KPCo IRP Report.

The results of such cost-benefit analyses have been shared with the KPCo DSM Collaborative (which includes a KDOE representative), as noted in the Response to Request No. 8, this set.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
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Kentucky Division of Energy's Request for Information, First Set
Dated December 20, 1999

Request No. 16:

Please provide a detailed description of the method KPCo uses to determine how much to charge a new residential, commercial, or industrial customer to hook up their building to the grid. Please explain why this particular method or formula was chosen.

Response:

Service connections to all KPCo customers -- residential, commercial and industrial -- are in accordance with the Kentucky Public Service Commission's Regulations, the Company's Terms and Conditions of Service, and the Company's Schedule of Tariffs, as approved and on file with the Commission.

Respondent: N. Tibberts

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Dated December 20, 1999

Request No. 17:

Did KPCo evaluate the cofiring of coal with sawdust at low percentages (e.g., less than 2 or 3 percent sawdust by weight) at existing coal-fired plants, which would provide a valuable service for the sawmill operations located in or near KPCo's service territory and also would reduce SO_2 emissions? Please explain the response.

Response:

AEP, on behalf of its operating companies, is continually evaluating the application of innovative technologies on its system. Although detailed studies have not been performed with respect to cofiring with sawdust (which is considered a biomass) for the Big Sandy Plant, AEP has conducted enough preliminary evaluations of biomass cofiring to determine that this technology does not appear economically viable for application at this time.

There are typically two concerns associated with burning biomass. The first is the availability of the material in the quantities required. A plant such as Big Sandy would require approximately 60,000-90,000 tons of biomass per year to displace 2-3 % of its fuel.

The second concern relates to economics. The benefits associated with the SO_2-emissions reduction (of approximately 5%) that would be achieved through biomass cofiring typically do not offset the costs of the biomass and the plant modifications required to accommodate biomass use.

Respondent: N. Tibberts

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February 29, 2000

FEB 29 2000

VIA HAND DELIVERY

Mr. Martin Huelsmann
Executive Director
Kentucky Public Service Commission
730 Schenkel Lane
P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: Kentucky Public Service Commission Case No. 99-437

Dear Mr. Huelsmann:

Please find enclosed and accept for filing an original and six copies of American Electric Power's responses to the following data requests:

1) Attorney General (2nd Set) Data Requests dated February 7, 2000;

2) PSC Staff (2nd Set) Data Requests dated February 8, 2000; and

3) KDOE (2nd Set) Data Requests dated February 8, 2000.

If you should have any questions please feel free to contact me.

Sincerely,

STITES & HARBISON

Judith A. Villines

Judith A. Villines

JAV/pjt
Enclosures

cc: Errol K. Wagner

KE057:KE115:3322:FRANKFORT

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING	)	
REPORT OF KENTUCKY POWER COMPANY	)	**CASE NO. 99-437**
D/B/A AMERICAN ELECTRIC POWER COMPANY	)	

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RESPONSE OF KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

to

ATTORNEY GENERAL (2ND SET) DATA REQUESTS
DATED FEBRUARY 7, 1999

FILED: FEBRUARY 29, 2000

INDEX

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN RE THE MATTER OF:

THE INTEGRATED RESOURCE PLANNING REPORT	)	
OF KENTUCKY POWER COMPANY d/b/a AMERICAN	)	Case No. 99-437
ELECTRIC POWER COMPANY	)	

THE ATTORNEY GENERAL'S
SUPPLEMENTAL REQUESTS FOR INFORMATION

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office for Rate Intervention, and submits these Requests for Information to ~~Delta Natural Gas Company~~, Kentucky Power Inc., to be answered in accord with the following:

(1) In each case where a request seeks data provided in response to a staff request, reference to the appropriate request item will be deemed a satisfactory response.

(2) Please identify the company witness who will be prepared to answer questions concerning each request.

(3) These requests shall be deemed continuing so as to require further and supplemental responses if the company receives or generates additional information within the scope of these requests between the time of the response and the time of any hearing conducted hereon.

(4) If any request appears confusing, please request clarification directly from the Office of Attorney General.

(5) To the extent that the specific document, workpaper or information as requested does not exist, but a similar document, workpaper or information does exist, provide the similar document, workpaper, or information.

(6) To the extent that any request may be answered by way of a computer printout, please identify each variable contained in the printout which would not be self evident to a person not familiar with

fax: nt, 1,900 p

the printout.

(7) If the company has objections to any request on the grounds that the requested information is proprietary in nature, or for any other reason, please notify the Office of the Attorney General as soon as possible.

(8) For any document withheld on the basis of privilege, state the following: date; author; addressee; indicated or blind copies; all persons to whom distributed, shown, or explained; and, the nature and legal basis for the privilege asserted.

(9) In the event any document called for has been destroyed or transferred beyond the control of the company state: the identity of the person by whom it was destroyed or transferred, and the person authorizing the destruction or transfer; the time, place, and method of destruction or transfer; and, the reason(s) for its destruction or transfer. If destroyed or disposed of by operation of a retention policy, state the retention policy.

Respectfully Submitted,

/s/ Blackford

ELIZABETH E. BLACKFORD
ASSISTANT ATTORNEY GENERAL
1024 CAPITAL CENTER DRIVE
FRANKFORT KY 40601
(502) 696-5453
FAX: (502) 573-4814

NOTICE OF FILING AND CERTIFICATE OF SERVICE

I hereby give notice that the original and ten copies of the foregoing were filed this the 7th day of February, 2000, with the Kentucky Public Service Commission at 211 Sower Blvd., Frankfort, Kentucky, 40601, and certify that on this same date true copies were served on the parties by mailing same, postage prepaid to:

Errol K. Wagner
Director of Regulatory Affairs
American Electric Power
P. O. Box 1428
Ashland, KY. 41105 1428

Honorable Judith A. Villines
Stites & Harbison
P. O. Box 634
Frankfort, KY. 40602 0634

John Stapleton

Director of Energy
Natural Resources and Environmental Protection
663 Teton Trail
Frankfort, KY. 40601

SS Blackford

SUPPLEMENTAL DATA REQUESTS OF THE ATTORNEY GENERAL

1. Follow-up to Item 2. For each of the last 5 years please provide:

a) Kilowatt-hours sold off-system by Kentucky Power to other AEP companies.

b) Kilowatt-hours sold off-system by Kentucky Power to non-affiliated companies.

c) Kilowatt-hours purchased by Kentucky Power from other AEP companies.

d) Kilowatt-hours purchased by Kentucky Power from non-affiliated companies.

e) If Kentucky Power looses its Rockport capacity in 2005 and this capacity is replaced with peaking units as called for in the IRP, please quantify how this will affect Kentucky Power's off-system purchases and sales, assuming the load levels contained in the IRP.

2. Follow-up to Items 7 and 8. The preliminary CO2 emissions in 1999 were 120 million of tons. The projected CO2 emissions for 2000 are 131 millions of tons. Please explain this apparent increase of 9% between 1999 and 2000.

3. Follow-up to Item 10. For each of the past 10 years, please provide the number of tons of coal and MCF of gas used by Kentucky Power, as reported in the annual FERC Form 1.

4. Follow-up to PSC Item 2. Please explain in detail how Kentucky Power and the other AEP companies operating under the AEP Interconnection Agreement, will be affected by joint dispatch with CSW, if the AEP-CSW system is jointly dispatched? Will the AEP Interconnection Agreement need to be amended?

5. Follow-up to KDOE Item 17. This response mentions two concerns and a preliminary evaluation that shows this technology does not appear to be economically viable. Given the volume of sawdust readily available from sawmills in eastern Kentucky, please provide the evaluation that lead to the conclusion that the technology was not economically viable.

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Supplemental Requests for Information
Dated February 7, 2000

Request No. 1:

Follow-up to Item 2. For each of the last 5 years please provide:

a. Kilowatt-hours sold off-system by Kentucky Power to other AEP companies.

b. Kilowatt-hours sold off-system by Kentucky Power to non-affiliated companies.

c. Kilowatt-hours purchased by Kentucky Power from other AEP companies.

d. Kilowatt-hours purchased by Kentucky Power from non-affiliated companies.

e. If Kentucky Power [loses] its Rockport capacity in 2005 and this capacity is replaced with peaking units as called for in the IRP, please quantify how this will affect Kentucky Power's off-system purchases and sales, assuming the load levels contained in the IRP.

Response:

a-d.

	Millions of kWh			
Year	Sold by KPCo to Other AEP Cos. (a)	Sold by KPCo to Non-affiliated Cos. (b)	Purchased by KPCo from Other AEP Cos. (c)	Purchased by KPCo from Non-affiliated Cos. (d)
1995	3,316	710	3,245	192
1996	2,294	1,386	4,388	139
1997	3,637	2,256	4,033	1,039
1998	3,734	1,149	3,300	600
1999 (not available)				

e. The off-system sales and purchases are transacted on an AEP System basis. KPCo participates in those transactions through its member-load-ratio share, in accordance with the AEP Interconnection Agreement. Thus, the replacement of KPCo's purchase of Rockport capacity with peaking units would not affect KPCo's allocated share of such transactions.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Supplemental Requests for Information
Dated February 7, 2000

Request No. 2:

Follow-up to Items 7 and 8. The preliminary CO_2 emissions in 1999 were 120 millions of tons. The projected CO_2 emissions for 2000 are 131 millions of tons. Please explain this apparent increase of 9% between 1999 and 2000.

Response:

The apparent increase of 9% between 1999 and 2000 was based on 1999 data that were both preliminary and incomplete. A final accounting of the CO_2 emissions for 1999 indicated that the total of such emissions for that year amounted to 126 million tons.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Supplemental Requests for Information
Dated February 7, 2000

Request No. 3:

Follow-up to Item 10. For each of the past 10 years, please provide the number of tons of coal and MCF of gas used by Kentucky Power, as reported in the annual FERC Form 1.

Response:

Year	Coal used by Big Sandy Plant (Millions of tons)
1989	2.6
1990	2.4
1991	2.0
1992	2.7
1993	2.3
1994	2.3
1995	3.0
1996	2.4
1997	2.9
1998	3.0
1999	3.1 (prelim.)

There was no gas used by Kentucky Power (i.e., Big Sandy Plant) during the past ten years.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Supplemental Requests for Information
Dated February 7, 2000

Request No. 4:

Follow-up to PSC Item 2. Please explain in detail how Kentucky Power and the other AEP operating companies operating under the AEP Interconnection agreement, will be affected by joint dispatch with CSW, if the AEP-CSW system is jointly dispatched? Will the AEP Interconnection Agreement need to be amended?

Response:

These issues were explained in the testimony and exhibits filed by Kentucky Power with the Commission in Case No. 99-149, in the Matter of the Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central and South West Corporation Regarding a Proposed Merger. The Office of the Attorney General was a party in that case and received a copy of the testimony and exhibits filed therein.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Supplemental Requests for Information
Dated February 7, 2000

Request No. 5:

Follow-up to KDOE Item 17. The response mentions two concerns and a preliminary evaluation that shows this technology does not appear to be economically viable. Given the volume of sawdust readily available from sawmills in eastern Kentucky, please provide the evaluation that lead to the conclusion that the technology was not economically viable.

Response:

See the Company's Response to Request No. 5 of the Kentucky Division of Energy's Second Request for information in this proceeding.

Respondent: N. Tibberts

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

FEB 29 2000

In the Matter of:

THE INTEGRATED RESOURCE PLANNING	)	
REPORT OF KENTUCKY POWER COMPANY	)	CASE NO. 99-437
D/B/A AMERICAN ELECTRIC POWER COMPANY	)	

****

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

to

PSC STAFF (2ND SET) DATA REQUESTS
DATED FEBRUARY 8, 1999

FILED: FEBRUARY 29, 2000

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COMMONWEALTH OF KENTCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INTEGRATED RESOURCE PLANNING REPORT OF KENTUCKY POWER COMPANY d/b/a AMERICAN ELECTRIC POWER TO THE KENTUCKY PUBLIC COMMISSION, OCTOBER, 1999	)))	CASE NO. 99-437

COMMISSION STAFF'S SUPPLEMENTALREQUEST FOR INFORMATION TO KENTUCKY POWER COMPANY – AMERICAN ELECTRIC POWER

The Commission Staff requests that an original and 6 copies of the following information be provided to the Staff, with a copy to all parties of record, by no later than the due date set out in the procedural schedule previously established for this case. Each copy of the data requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 5. Include with each response the name of the person responsible for responding to questions relating to the information provided.

1. Refer to the response to Item 4 of the Staff's initial information request which indicates that the forecasting service provided by DRI was significantly more expensive than the RFA forecasting service. Provide the savings realized by AEP as a result of switching from DRI to RFA and show the portion of that savings allocated to or realized by Kentucky Power.

2. Refer to the response to Item 7 of the Staff' initial information request which indicates that, among other things, cost was one of the reasons for switching from an AEP-produced regional economic forecast to the forecast developed by Woods & Poole. Identify the amount of cost savings realized as a result of this change and the portion of the savings allocated to or realized by Kentucky Power.

3. Refer to the attachment to the response to Item 9 of the Staff's initial information request, where a number of binary variables are included in the regression equations. Explain the significance of each of the years chosen as binary variables.

4. Refer to the response to Item 13, part C, of the Staff's initial information request, where it is stated that "Such a short term energy requirements forecast has not been developed and, therefore, the requested results are not available". Given that the long-term forecasting models include incomes and energy prices (stated on page 2-2) as regressors, explain why a short-term energy requirements forecast has not been developed to include these variables.

5. Refer to the response to Item 14 of the Staff's initial information request.

   a. Part (a) states that "The requested re-estimation has never been developed and, therefore, cannot be provided." If this is so, explain why some of the short-term models are estimated via Proc Autoreg and the Yule-Walker method (also known as Prais-Winsten), which SAS is capable of performing.

b. In the response to part b, it is stated that "A low Durbin-Watson statistic is a well-known symptom ... of specification problems such as omitted variables." Given this, explain why no income variable was included in the USE equation.

6. Refer to the response to Item 15 of the Staff's initial information request. Explain why there currently is little need for modeling forecasts by major SIC codes as was done in previous IRPs.

7. Refer to the attachment to the response to Item 25 of the Staff's initial information request concerning average on-peak equivalent availability factors ("EAF").

a. Regarding AEP-operated fossil steam units, identify the factors which caused the annual EAF to increase to 84 percent in 1996 when it had not exceeded 79.8 percent during any of the six previous years.

b. After reaching 85.5 percent in 1997, the annual EAF for AEP-operated steam units declined slightly in each of the two following years, reaching 82.2 percent in 1999. Given this history, explain in detail the basis for projected EAF ranging from 86.2 to 88.1 percent throughout the forecast period.

8. Refer to the response to Item 28 of the Staff's initial information request regarding the mix of contract and spot coal purchases by AEP. For the contract purchases for the last three years shown (1996-1998), provide the following information:

   a. Tons mined – by state of origin.

   b. Tons by type, i.e. – low sulfur, medium sulfur, high sulfur, etc.

   c. Tons purchased - by AEP operating company.

9. Refer to the response to Item 29 of the Staff's initial information request.

   a. Provide the cost incurred for the dual-fuel capability modification of Conesville Units 1-3 as part of AEP's compliance plan.

   b. Identify the emission reductions that have been realized as a result of the modifications of these units to enable them to burn an alternative fuel.

   c. Given the results with these units, identify the extent to which similar modifications at other units might be included as part of AEP's future compliance plans.

Respectfully submitted.

Richard G. Raff
Staff Attorney

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Supplemental Request for Information
Dated February 8, 2000

Request No. 1:

Refer to the response to Item 4 of the Staff's initial information request which indicates that the forecasting service provided by DRI was significantly more expensive than the RFA forecasting service. Provide the savings realized by AEP as a result of switching from DRI to RFA and show the portion of that savings allocated to or realized by Kentucky Power.

Response:

AEP paid DRI approximately $30,000 annually for its data and forecasting services. It now pays RFA about $12,000 for a very similar product, which translates to an annual savings of $18,000. Kentucky Power's allocated share of that savings is estimated to be about $1,000.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
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Dated February 8, 2000

Request No. 2:

Refer to the response to Item 7 of the Staff's initial information request which indicates that, among other things, cost was one of the reasons for switching from an AEP-produced regional economic forecast to the forecast developed by Woods & Poole. Identify the amount of cost savings realized as a result of this change and the portion of the savings allocated to or realized by Kentucky Power.

Response:

No explicit estimate of the referred-to savings has ever been performed. However, AEP pays Woods & Poole roughly $1,000 annually for its regional economic data and forecasting services. When the regional economic forecast was being produced in-house, $60,000 in wages and benefits would be a conservative estimate of the resources devoted to it. This suggests a savings of $59,000, of which Kentucky Power's share would be in the order of $3,000.

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Supplemental Request for Information
Dated February 8, 2000

Request No. 3:

Refer to the attachment to the response to Item 9 of the Staff's initial information request, where a number of binary variables are included in the regression equations. Explain the significance of each of the years chosen as binary variables.

Response:

In the coal production equation, the variables "D83" and "D88" represent declines in regional coal production that were not accounted for by the other exogenous variables. Likewise, "D95ON" reflects reduction in regional coal production relative to the trends reflected in the exogenous variables.

The "D86ON" variable in the industrial gas price model and the electric utility gas price model was utilized to capture some of the effects of deregulation of the wholesale natural gas markets. The "D94ON" and "D97ON" variables in the electric utility gas price model, and the "D95ON" variable in the residential, commercial and industrial natural gas price models, were utilized to reflect recent model errors (i.e., deviations of model estimates from actual values for the recent years) that were not accounted for by the exogenous variables

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
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Dated February 8, 2000

Request No. 4:

Refer to the response to Item 13, part C, of the Staff's initial information request, where it is stated that "such a short term energy requirements forecast has not been developed and, therefore, the requested results are not available." Given that the long-term forecasting models include incomes and energy prices (stated on page 2-2) as regressors, explain why a short-term energy requirements forecast has not been developed to include these variables.

Response:

As explained in the response to Item/Request No. 8 of the Staff's initial information request in this proceeding, the effects of income and energy prices are treated implicitly in the short-term models through the application of time trends. In that response, the term "regional economic growth" is intended to comprehend such measures of extensive economic growth as employment and income.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Supplemental Request for Information
Dated February 8, 2000

Request No. 5:

Refer to the response to Item 14 of the Staff's initial information request.

a. Part (a) states that "The requested re-estimation has never been developed and, therefore, cannot be provided." If this is so, explain why some of the short-term models are estimated via Proc Autoreg and the Yule-Walker method (also known as Prais-Winsten), which SAS is capable of performing.

b. In the response to part b, it is stated that "A low Durbin-Watson statistic is a well-known symptom . . . of specification problems such as omitted variables." Given this, explain why no income variable was included in the USE equation.

Response:

a. Electric loads for short intervals of time often tend to exhibit autocorrelation. One source of autocorrelation in the monthly energy sales modeled in the short-term equations is that the accounting algorithm that estimates billed and accrued energy sales for any given month (this being the unobserved quantity of energy consumed during a given month as opposed to the observed quantity billed in that month) is capable of providing only approximate results. The effect of this is that some of the energy reported as billed and accrued in a given month is, in fact, consumed in the previous calendar month, with the result that a given month's energy sales are correlated with those of the previous month.

Beyond these considerations of how the Company's accounts are reckoned, it was supposed that the unexplained sources of variation in monthly energy sales that the analysis treats as random and uncorrelated with the independent variables, and that are approximately represented by the monthly model errors, are associated with circumstances and events which, while unknown, are nevertheless likely often to be of greater than monthly duration (or, at least, correlated from month to month).

Request No. 5

Response (cont'd)

The analogous reasoning does not apply, however, to annual electric loads. The errors introduced by the monthly "billed and accrued" algorithm, while sometimes significant in relation to a single month's energy sales, are insignificant in relation to annual energy sales. Also, there is scant basis for supposing that the unexplained sources of variation in *annual* energy sales, which the analysis treats as random, and which are approximately represented by the *annual* model errors, are associated with circumstances and events that are of greater than *annual* duration. Events affecting energy sales that are of *annual* or longer duration are likely to be observed, to be understood, and to be accounted for by the independent variables of the model. As stated in the response to part b of Item/Request No. 14, "there is scant basis in economic theory or in practical experience for hypothesizing that annual electric loads exhibit an autocorrelated error process."

For all of these reasons, some of the short-term models are estimated upon the assumption that the error processes are autocorrelated, while the analogous assumption was never seriously entertained in the annual analyses. The software is capable, of course, of performing a host of alternative estimation procedures, very few of which were regarded as worthy of serious consideration.

It may be worth observing that, generally in the analysis of time series, the usefulness of an elaborate error specification diminishes as the interval of time considered by the analysis increases. Short-term forecast errors are very often associated with the unexplained variations in load, which are treated as random in short-term models. Long-term forecast errors, when finally recorded, are more often associated with incorrect forecasts of independent variables or some other, similar, failure of fundamental assumptions.

b. Service-area employment was included in the USE equation as a measure of regional economic growth. Either employment or income can be used as a measure of regional economic growth.

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

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Dated February 8, 2000

Request No. 6:

Refer to the response to Item 15 of the Staff's initial information request. Explain why there currently is little need for modeling forecasts by major SIC codes as was done in previous IRPs.

Response:

Although information on load by SIC might be of interest to some for certain other purposes, such information is not a particularly useful basis for power system planning.

Respondent: N. Tibberts

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Supplemental Request for Information
Dated February 8, 2000

Request No. 7:

Refer to the attachment to the response to Item 25 of the Staff's initial information request concerning average on-peak equivalent availability factors ("EAF").

a. Regarding AEP-operated fossil steam units, identify the factors which caused the annual EAF to increase to 84 percent in 1996 when it had not exceeded 79.8 percent during any of the six previous years.

b. After reaching 85.5 percent in 1997, the annual EAF for AEP-operated steam units declined slightly in each of the two following years, reaching 82.2 percent in 1999. Given this history, explain in detail the basis for projected EAF ranging from 86.2 to 88.1 percent throughout the forecast period.

Response:

a. A reduction, in 1996, in planned/scheduled capacity outages was the most significant factor contributing to the improvement in the on-peak equivalent availability factor for the AEP-operated fossil steam units.

b. As the figures indicate, compared to, say, the EAF for 1999 (82.2 percent), the projected EAFs for the forecast period (86.2 to 88.1 percent) are about 4 to 6 percentage points higher. Of this increase, 4 percentage points could be attributed to expected reductions in forced capacity outages. The rest of the increase, 0-2 percentage points, could be attributed to expected reductions in planned/scheduled capacity outages.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Supplemental Request for Information
Dated February 8, 2000

Request No. 8:

Refer to the response to Item 28 of the Staff's initial information request regarding the mix of contract and spot coal purchases by AEP. For the contract purchases for the last three years shown (1996-1998), provide the following information:

a. Tons mined - by state of origin.

b. Tons by type, i.e. - low sulfur, medium sulfur, high sulfur, etc.

c. Tons purchased - by AEP operating company.

Response:

a. Millions of tons mined – by state of origin:

State of Origin	1996	1997	1998
Kentucky	3.5	3.3	3.0
Ohio	11.9	12.9	12.0
Virginia	2.2	2.1	2.0
West Virginia	16.2	16.6	17.9
Wyoming	8.7	8.4	8.2

b. Millions of tons by type, i.e., sulfur content:

Sulfur Content (%)	1996	1997	1998
Less Than 0.70	14.5	14.0	13.2
0.70 to 1.50	13.6	13.3	14.6
1.50 to 2.50	1.1	1.7	1.8
2.50 or More	13.3	14.3	13.5

c. Millions of tons purchased – by AEP operating company:

Operating Company	1996	1997	1998
Appalachian Power Company	11.3	11.7	11.9
Ohio Power Company	16.6	17.2	17.2
Columbus Southern Power Company	2.8	3.2	3.4
Indiana Michigan Power Company	9.6	9.2	8.9
Kentucky Power Company	2.2	2.0	1.7

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Supplemental Request for Information
Dated February 8, 2000

Request No. 9:

Refer to the response to Item 29 of the Staff's initial information request.

a. Provide the cost incurred for the dual-fuel capability modification of Conesville Units 1-3 as part of AEP's compliance plan.

b. Identify the emission reductions that have been realized as a result of the modifications of these units to enable them to burn an alternative fuel.

c. Given the results with these units, identify the extent to which similar modifications at other units might be included as part of AEP's future compliance plans.

Response:

a. The total cost incurred at Conesville Units 1-3 for dual-fuel capability modification was \$9.3 million.

b. The SO_2 emission reductions that have been realized as a result of burning the alternative fuel (gas) amounted to 2,082 tons in 1995 and 291 tons in 1999. Any greater utilization of the alternative fuel could not have been economically justified.

c Several other candidate facilities have been identified on the AEP System. Adding dual-fuel capability is one of many alternatives continually evaluated as part of AEP's overall compliance strategy. Currently, there are no near-term modifications for dual-fuel capability planned for any other AEP facilities.

Respondent: N. Tibberts

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING	)	
REPORT OF KENTUCKY POWER COMPANY	)	**CASE NO. 99-437**
D/B/A AMERICAN ELECTRIC POWER COMPANY	)	

****

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

to

KDOE (2nd SET) DATA REQUESTS
DATED FEBRUARY 8, 2000

FILED: FEBRUARY 29, 2000

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING REPORT OF THE KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER TO THE KENTUCKY PUBLIC SERVICE COMMISSION, OCTOBER, 1999	)))))	CASE NO. 99-437

KENTUCKY DIVISION OF ENERGY'S SECOND REQUEST FOR INFORMATION TO THE KENTUCKY POWER COMPANY

Comes the Natural Resources and Environmental Protection Cabinet, Division of Energy (KDOE), Intervenor herein, and makes the following second request for information for the purpose of evaluating the effectiveness of the proposed integrated resource plan (IRP):

1. During KDOE's participation in the DSM Collaborative, we do not recall the Collaborative being involved in the process of developing Kentucky Power Company's (KPCo) 1996 or 1999 IRP Reports to the Commission. Does KPCo believe that it might be beneficial to get the perspective of the Collaborative on aspects of IRP planning that relate to demand-side management? Please explain the response.

2. Please refer to KDOE's Request No. 8, 1st Set. We interpret the first sentence of the response to mean that 1994 was the last time AEP analyzed a wide range of DSM options and measures. If this interpretation is incorrect, please explain.

faxed D.T. 2-9-00 [illegible]

3. In responding to KDOE's Request No. 15, 1st Set, dealing with local integrated resource planning (LIRP), KPCo stated that it uses both system-wide and localized planning perspectives. The response then referred to page 3-7 of the 1999 IRP report. There is a sentence in the second full paragraph that relates to this topic: "Avoided costs for transmission and distribution, expressed in $/kW, were estimated based on historical and projected capital expenditures for general system development projects that are related to load growth."

To KDOE, this implies that KPCo uses system-wide average values for T&D costs when calculating avoided costs. If this is the procedure KPCo is using, it represents precisely the opposite of the LIRP concept. According to the E Source Strategic Issues Paper referenced in KDOE's Request No. 15, 1st Set, LIRP's early applications have been "at the project level to assist in targeting expensive T&D upgrade or expansion projects that might be deferrable. Once such projects are identified, LIRP methodology guides planners through a comprehensive technical and economic evaluation of the *local* alternatives to the specific targeted upgrade." (page 3, under "LIRP Defined," emphasis in original)

To paraphrase KDOE's Request No. 15, 1st Set, in more specific terms:

a. Did KPCo identify particularly expensive T&D upgrade or expansion projects that might be deferrable, and having identified such projects, conduct a comprehensive technical and economic evaluation of the local supply-side and demand-side alternatives to the specific targeted upgrades?

b. Does KPCo plan to use such an approach, also known as LIRP, in the future?

4. In responding to KDOE's Request No. 16, 1st Set, dealing with hookup fees, KPCo referred to the Company's schedule of Tariffs, as approved and on file with the Commission. The Tariff Library web page linked to the Commission's internet site appears to be

missing the relevant pages, and the recent relocation of the Commission's offices has made other methods of obtaining these pages from the Commission difficult.

a. Please provide a copy of the pages that specify how hookup fees are calculated for residential, commercial, and industrial customers.

b. Please explain the economic rationale that underlies the hookup fee formulas now in effect.

5. KDOE's Request No. 17, 1st Set, asked about cofiring coal with sawdust at low percentages. In its response, KPCo raised two concerns: whether enough sawdust (biomass) would be available, and the economics – whether the biomass could be purchased cheaply enough and whether costly modifications would need to be made to the power plants.

a. Was AEP aware that at several power plants in the Southeast, cofiring of coal with limited percentages of sawdust has been accomplished in a cost-effective manner?

b. Would the availability of sawdust at very low or zero cost affect AEP's conclusions about the economics?

c. Were the economic benefits that could accrue to the forest products industry [i.e., avoided waste disposal costs] factored into AEP's preliminary evaluations of biomass cofiring? If not, why not?

6. In its Joint Integrated Resource Plan, submitted to the Commission on November 22, 1999, LG&E/KU found it advantageous to include the following demand-side programs [among others]:

- Direct load control of residential and commercial central air conditioners and water heaters and residential swimming pool pumps – 110.7 MW, with the first phase of 22.1 MW occurring in 2001 and with four comparable additional phases in the years 2002 to 2005;

- A special rate to enable the utility to use standby generation resources of participating commercial and industrial customers during peak load periods – 82.4 MW, with the first phase of 20.6 MW in 2002 and with three comparable phases in subsequent years (Reference: Case No. 99-430, Volume III, Sections IV and VII).

Has KPCo considered the potential net economic benefits that could accrue both to customers and shareholders by giving the utility some degree of influence or control over the energy use of participating customers during peak load periods, as programs such as those described above attempt to do?

7. Net metering has been instituted in some 30 states, and has been proposed to take effect on a national level through legislation titled the "Home Energy Generation Act," introduced by U.S. Representative Jay Inslee. Potential advantages of net metering include encouraging distributed generation, increasing the diversity of generation sources, reducing line losses, and reducing overall system costs if the customer-generator produces power during peak periods [e.g., a customer-owned photovoltaic system that produces at maximum output on a hot, sunny summer day].

a. If net metering were to be instituted on a national or statewide level, what would be the estimated impact on energy use and demand in the KPCo service area over the next 20 years?

b. Has KPCo considered proposing a net metering policy or tariff?

8. To what extent has KPCo encouraged the installation of combined heat and power (cogeneration) systems by industrial firms in its service area? Please provide quantitative information if available.

Respectfully submitted,

IRIS SKIDMORE
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Office of Legal Services
Fifth Floor, Capital Plaza Tower
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Telephone: (502) 564-6676

COUNSEL FOR NATURAL RESOURCES
AND ENVIRONMENTAL PROTECTION

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Second Request for Information
Dated February 8, 2000

Request No. 1:

During KDOE's participation in the DSM Collaborative, we do not recall the Collaborative being involved in the process of developing Kentucky Power Company's (KPCo) 1996 or 1999 IRP Reports to the Commission. Does KPCo believe that it might be beneficial to get the perspective of the Collaborative on aspects of IRP planning that relate to demand-side management? Please explain the response.

Response:

The development of KPCo's IRP Reports to the Commission is the responsibility of AEP/KPCo. As part of the process of developing both the 1996 Report and the 1999 Report, a DSM plan was developed, with the involvement of the KPCo DSM Collaborative, and incorporated into the integrated resource plan.

In connection with the Collaborative's involvement, as indicated in the Company's Response to KDOE's Request No. 9 (part b), First Set, a main objective of the Collaborative is to develop DSM programs for KPCo. Further, as stated in the KPCo By-laws of the Collaborative (Article I, Section 3 -- Duties of Membership), among the membership duties is "to review, to recommend, and to endorse DSM Programs for Kentucky Power." Although it is not the responsibility of the Collaborative to develop KPCo's IRP Reports, the Company believes that the development of KPCo's DSM programs by the Collaborative has reflected the Collaborative's perspective on those aspects of integrated resource planning that relate to demand-side management.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Second Request for Information
Dated February 8, 2000

Request No. 2:

Please refer to KDOE's Request No. 8, 1st Set. We interpret the first sentence of the response to mean that 1994 was the last time AEP analyzed a wide range of DSM options and measures. If this interpretation is incorrect, please explain.

Response:

As indicated in the Company's Response to KDOE's Request No. 8, First Set, 1994 was the last time that extensive analyses were performed on a wide range of DSM options and measures from an AEP perspective. Additional analyses were performed in 1995 and 1996 to modify or update those options or measures, including adding new options to the DSM measure-screening process.

Analyses were also performed on numerous options and measures provided by the KPCo DSM Collaborative in 1995, and additional analyses were performed routinely on those DSM programs implemented in KPCo's service territory.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Second Request for Information
Dated February 8, 2000

Request No. 3:

In responding to KDOE's Request No. 15, 1st Set, dealing with local integrated resource planning (LIRP), KPCo stated that it uses both system-wide and localized planning perspectives. The response then referred to page 3-7 of the 1999 IRP Report. There is a sentence in the second full paragraph that relates to this topic: "Avoided costs for transmission and distribution, expressed in $/kW, were estimated based on historical and projected capital expenditures for general system development projects that are related to load growth."

To KDOE, this implies that KPCo uses system-wide average values for T&D costs when calculating avoided costs. If this is the procedure KPCo is using, it represents precisely the opposite of the LIRP concept. According to the E Source Strategic Issues Paper referenced in KDOE's Request No. 15, 1st Set, LIRP's early applications have been "at the project level to assist in targeting expensive T&D upgrade or expansion projects that might be deferrable. Once such projects are identified, LIRP methodology guides planners through a comprehensive technical and economic evaluation of the *local* alternatives to the specific targeted upgrade." (page 3, under "LIRP Defined," emphasis in original)

To paraphrase KDOE's Request No. 15, 1st Set, in more specific terms:

a. Did KPCo identify particularly expensive T&D upgrades or expansion projects that might be deferrable, and having identified such projects that might be deferrable, conduct a comprehensive evaluation of the local supply-side and demand-side alternatives to the specific targeted upgrades?

b. Does KPCo plan to use such an approach, also known as LIRP, in the future?

Response:

To begin with, in the calculation of projected avoided costs for use in the cost-benefit analyses of demand-side management programs for KPCo, the Company does not use AEP System-wide values for avoided T&D costs. Rather, such costs are KPCo-based.

Request No. 3

Response (cont'd)

With respect to T&D upgrades and expansion projects, the Company's objective is to serve its customers in the most efficient, effective and economical means feasible. Thus, traditional and/or "LIRP" or equivalent concepts are applied in the planning process, as appropriate, with particular emphasis on the lowest-cost solution for transmission and distribution combined.

An example in this regard is the recently completed Big Sandy/Inez project, which involved the upgrading and reinforcement of the Company's 138-kV transmission system in the Inez and Tri-state areas, as noted in KPCo's 1999 IRP Report (page 4-14). This project, which included the installation of the first Unified Power Flow Controller (UPFC) anywhere in the world, was the most appropriate solution, among all feasible alternatives, for resolving system performance problems in these areas and providing adequate service to customers during expected normal conditions, as well as single- and double-contingency outage conditions. As a result, this project enabled the Company to avoid pursuing a more expensive project, involving the construction of a 345-kV transmission line and associated facilities. Further, this UPFC device introduced a new dimension in controlling transmission system power flows and voltages, thereby providing increased flexibility to meet the demands of open transmission access.

Also, it is important to note that the Big Sandy/Inez project has contributed materially to reducing real power system losses (by an estimated 24 MW). In this regard, as KPCo's 1999 IRP Report also notes, on page 4-14, "AEP and its operating companies continually explore opportunities for improving the efficiency of utilization of their power supply facilities, . . . and . . . . opportunities for reductions in system losses is a major consideration in planning such facilities. Reduction in these losses represents, in effect, conservation of energy resources on the 'utility side' of the meter."

As was the case with the Big Sandy/Inez project, as opportunities arise, KPCo expects to continue to explore and apply whatever methods are appropriate with respect to the T&D planning process, including traditional and/or "LIRP" or equivalent concepts.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Second Request for Information
Dated February 8, 2000

Request No. 4:

In responding to KDOE's Request No. 16, 1st Set, dealing with hookup fees, KPCo referred to the Company's schedule of Tariffs, as approved and on file with the Commission. The Tariff Library web page linked to the Commission's internet site appears to be missing the relevant pages, and the recent relocation of the Commission's offices has made other methods of obtaining these pages from the Commission difficult.

a. Please provide a copy of the pages that specify how hookup fees are calculated for residential, commercial, and industrial customers.

b. Please explain the economic rationale that underlies the hookup fee formulas now in effect.

Response:

a. See the accompanying Attachment 1, which consists of 3 pages: copies of Tariff Sheet Nos. 2-1, 2-5 and 2-6, respectively.

b. If a customer requests service from the Company, thus requiring the Company to incur the costs of providing that service, the Company attempts to have the customer pay for such costs. In the ratemaking arena, this is known as the principle of assigning the cost to the cost-causer.

TERMS AND CONDITIONS OF SERVICE

1. APPLICATION.

A copy of the tariffs and standard terms and conditions under which service is to be rendered to the Customer will be furnished upon request at the Company's office and the Customer shall elect upon which tariff applicable to his service his application shall be based.

A written agreement may be required from each Customer before service will be commenced. A copy of the agreement will be furnished to the Customer upon request.

When the Customer desires delivery of energy at more than one point, a separate agreement will be required for each separate point of delivery. Service delivered at each point of delivery will be billed separately under the applicable tariff.

2. INSPECTION.

It is to the interest of the Customer to properly install and maintain his wiring and electrical equipment and he shall at all times be responsible for the character and condition thereof. The Company makes no inspection thereof and in no event shall be responsible therefor.

Where a Customer's premises are located in a municipality or other governmental subdivision where inspection laws or ordinances are in effect, the Company may withhold furnishing service to new installations until it has received evidence that the inspection laws or ordinances have been complied with.

Where a Customer's premises are located outside of an area where inspection service is in effect, the Company may require the delivery by the Customer to the Company of an agreement duly signed by the owner and tenant of the premises authorizing the connection to the wiring system of the Customer and assuming responsibility therefor. No responsibility shall attach to the Company because of any waiver of this requirement.

3. SERVICE CONNECTIONS.

Service connections will be provided in accordance with 807 KAR 5:041, Section 10.

The Customer should in all cases consult the Company before his premises are wired to determine the location of Company's point of service connection.

The Company will, when requested to furnish service, designate the location of its service connection. The Customer's wiring must, except for those cases listed below, be brought outside the building wall nearest the Company's service wires so as to be readily accessible thereto. When service is from an overhead system, the Customer's wiring must extend at least 18 inches beyond the building. Where Customers install service entrance facilities which have capacity and layout specified by the Company and/or install and use certain utilization equipment specified by the Company, the Company may provide or offer to own certain facilities on the Customer's side of the point where the service wires attach to the building.

All inside wiring must be grounded in accordance with the requirements of the National Electrical Code or the requirements of any local inspection service authorized by a state or local authority.

When a Customer desires that energy be delivered at a point or in a manner other than that designated by the Company, the Customer shall pay the additional cost of same.

(Cont'd on Sheet No. 2-2)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

9. EXTENSION OF SERVICE.

The electric facilities of the Company shall be extended or expanded to supply electric service to all residential Customers and small commercial Customers which require single phase line where the installed transformer capacity does not exceed 25 KVA in accordance with 807 KAR 5:041, Section 11.

The electric facilities of the Company shall be extended or expanded to supply electric service to Customers other than those named in the above paragraph when the estimated revenue is sufficient to justify the estimated cost of making such extensions or expansions as set forth below.

For service to be delivered to Commercial, Industrial, Mining and multiple housing project Customers up to and including estimated demands of 500 KW requiring new facilities, the Company will: (a) where the estimated revenue for one year exceeds the estimated installed cost of new local facilities required, provide service at no cost to the Customer; (b) where the estimated revenue for one year is less than the installed cost of new local facilities required, the Customer will be required to pay a contribution in aid of construction equal to the difference between the installed cost of the new facilities required to serve the load and the estimated revenue for one year; (c) where the Company has reason to question the financial stability of the Customer and/or the life of the operation is uncertain or temporary in nature, such as construction projects, oil and gas well drilling, sawmills and mining operations, the Customer shall pay a contribution in aid of construction, consisting of the estimated labor cost to install and remove the facilities required plus the cost of unsalvagable material, before the facilities are installed.

For service to be delivered to Customers with demand levels higher than those specified above, the annual cost to serve the Customer's requirements shall be compared with the estimated revenue for one year to determine if a contribution in aid of construction, and/or a special minimum and/or other arrangement may be necessary. The annual cost to service shall be the sum of the following components:

1. The annual fixed costs of the generation, transmission and distribution facilities related to the Customer's requirements. These fixed costs will be calculated at 21.95% of the value to be based on the year-end embedded investment depreciated in all similar facilities of the Company.

2. The annual energy costs based on the latest available production costs related to the Customer's estimated annual energy use requirements.

3. The annual fixed costs of the new local facilities necessary to provide the service requested calculated at 21.95% of the installed cost of such facilities.

If the estimated revenue for one year is greater than the cost to serve as described herein, the Company may provide service at no cost to the Customer. If the estimated revenue for one year is less than the cost to serve as described herein, the Company will require the Customer to pay a contribution in aid of construction equal to the difference between the annual cost to serve as calculated and the estimated revenue for one year divided by 21.95%, but in no case to exceed the installed cost of the new facilities required. If, however, the annual cost to serve excluding the cost of new facilities paid for by the Customer, exceeds the estimated revenue for one year, the Company, will, in addition to a contribution in aid of construction, require a special minimum or other arrangement to compensate the Company for such deficiency in revenue.

Except where service is rendered in accordance with 807 KAR 5:041, Section 11, as described herein, the Company may require the Customer to execute an Advance and Refund Agreement where there may be question as to longevity of the service or the estimated energy use and demand requirements provided by the Customer. Under the Advance and Refund Agreement, the Customer shall pay the Company the estimated total installed cost of the required new facilities which advance could be refunded over a five year period under certain conditions. Over the five year period the Customer's electric bill would be credited each month up to the amount of 1/60th of the total amount advanced. Such credit shall be applied only to that portion of the Customer's bill which exceeds a specified minimum. A minimum before refund shall be established as the greater of: (1) the minimum as described under the applicable tariff or (2) the amount representing 1/12th of the calculated annual cost to serve as described herein. In the event the Customer's monthly bill in any month does not exceed such minimum by an amount equal to 1/60th of the amount advanced, the difference between 1/60th of the amount advanced and the amount, if any, actually credited to the Customer's bill shall be designated as "accrued credit" and applied to future monthly bills as credit where such monthly bills exceed the established minimum by more than 1/60th of the amount advanced.

(Cont'd on Sheet No. 2-6)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

10. EXTENSION OF SERVICE TO MOBILE HOME.

The electrical facilities of the Company will be extended or expanded to supply electric service to mobile homes in accordance with 807 KAR 5:041, Section 12.

11. LOCATION AND MAINTENANCE OF COMPANY'S EQUIPMENT.

The Company shall have the right to construct its poles, lines and circuits on the property, and to place its transformers and other apparatus on the property or within the building of the Customer, at a point or points convenient for such purposes, as required to serve such Customer, and the Customer shall provide suitable space for the installation of necessary measuring instruments so that the latter may be protected from injury by the elements or through the negligence or deliberate acts of the Customer or of any employee of the same.

12. BILLING FORM

Pursuant to 807 KAR 5:006, Section 6(3) copies of the billing forms used by the Company is shown on Sheet Nos. 2-9, 2-10 and 2-11.

13. RATE SCHEDULE SELECTION.

When more than one rate schedule is available for the service requested, Customer shall designate the rate schedule on which the application or contract shall be based. Company will assist Customer in the selection of the rate schedule best adapted to Customer's service requirements, provided, however, that Company does not assume responsibility for the selection or that Customer will at all times be served under the most favorable rate schedule.

Customer may change his initial rate schedule selection to another applicable rate schedule at any time by either written notice to Company and/or by executing a new contract for the rate schedule selected, provided that the application of such subsequent selection shall continue for 12 months before any other selection may be made. In no case will the Company refund any monetary difference between the rate schedule under which service was billed in prior periods and the newly selected rate schedule.

14. MONITORING USAGE

At least once annually the Company will monitor the usage of each customer according to the following procedure:

1. The customer's monthly usage will be compared with the usage of the corresponding period of the previous year.

2. If the monthly usage for the two periods are substantially the same or if any difference is known to be attributed to unique circumstances, such as unusual weather conditions, common to all customers, no further review will be made.

3. If the monthly usage is not substantially the same and cannot be attributed to a readily identified common cause, the Company will compare the customer's monthly usage records for the 12-month period with the monthly usage for the same months of the preceding year.

4. If the cause for the usage deviation cannot be determined from analysis of the customer's meter reading and billing records, the Company will contact the customer to determine whether there have been changes that explain the increased usage.

5. Where the deviation is not otherwise explained, the Company will test the customer's meter to determine whether it shows an average error greater than 2 percent fast or slow.

6. The Company will notify the customers of the investigation, its findings, and any refunds or backbilling in accordance with 807 KAR 5:006, Section 10(4) and (5).

In addition to the annual monitoring, the Company will immediately investigate usage deviations brought to its attention as a result of its on-going meter reading or billing processes or customer inquiry.

(Cont'd on Sheet No. 2-7)

5

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Second Request for Information
Dated February 8, 2000

Request No. 5:

KDOE's Request No. 17, 1st Set, asked about cofiring coal with sawdust at low percentages. In its response, KPCo raised two concerns: whether enough sawdust (biomass) would be available, and the economics - whether the biomass could be purchased cheaply enough and whether costly modifications would need to be made to the power plants.

a. Was AEP aware that at several power plants in the Southeast, cofiring of coal with limited percentages of sawdust has been accomplished in a cost-effective manner?

b. Would the availability of sawdust at very low or zero cost affect AEP's conclusions about the economics?

c. Were the economic benefits that could accrue to the forest products industry [i.e., avoided waste disposal costs] factored into preliminary evaluations of biomass cofiring? If not, why not?

Response:

a. AEP does not have information on the specifics of the cost-effectiveness of the referenced power plants. Cofiring with limited percentages can be accomplished cost effectively, depending on the type of boiler being fired and the transportation required for the biomass to the power plant. However, biomass cofiring could require capital-intensive boiler and material handling modifications, which, together with longer transportation runs, could result in a benefit that is marginal to negative.

The Company's review of the current situation at the Big Sandy Plant led to the conclusion that significant modifications would be required to cofire sawdust at that plant. The added capital expense and required system installations to burn sawdust would require a minimum tipping fee of $4.41/ton (which the sawdust supplier would pay to KPCo, exclusive of transportation costs), in order to compensate the Company for the associated increase in power production costs. With the plant located at the border of Kentucky (and, hence, not centrally located with respect to Kentucky's wood processing plants), transportation costs to deliver sawdust to the plant from sources within the state would tend to be maximized because of the relatively long distances involved.

Request No. 5

Response (cont'd)

b. No; if sawdust were delivered at zero cost to the Big Sandy Plant, the result would still be a net increase in the plant's power production costs, because of the need for capital-intensive boiler and material handling modifications. Also, the boiler modifications would need to be approved by the U.S. Environmental Protection Agency (EPA). In this regard, EPA's new source standards might not allow 100% coal firing if the biomass supply were interrupted or became uneconomical.

c. The cost of transporting sawdust has been conservatively estimated to be $20/ton (excluding equipment and labor). This cost, together with the tipping fee of $4.41/ton (as noted in the response to part a above), would raise the total cost to dispose of the sawdust at Big Sandy Plant to $24.41/ton. This is a relatively high cost compared to the Company's own experience with respect to waste product disposal (e.g., flyash).

Respondent: N. Tibberts

6

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Second Request for Information
Dated February 8, 2000

Request No. 6:

In its Joint Integrated Resource Plan, submitted to the Commission on November 22, 1999, LG&E/KU found it advantageous to include the following demand-side programs [among others]:

- Direct load control of residential and commercial central air conditioners and water heaters and residential swimming pool pumps - 110.7 MW, with the first phase of 22.1 MW occurring in 2001 and with four comparable additional phases in the years 2002 to 2005;

- A special rate to enable the utility to use standby generation resources of participating commercial customers during peak load periods - 82.4 MW, with the first phase of 20.6 MW in 2002 and with three comparable phases in subsequent years (Reference: Case No. 99-430, Volume III, Sections IV and VII).

Has KPCo considered the potential net economic benefits that could accrue both to customers and shareholders by giving the utility some degree of influence or control over the energy use of participating customers during peak load periods, as programs such as those described above attempt to do?

Response:

Yes; AEP/KPCo has considered and analyzed the potential net economic benefits, to both customers and the Company (including the Company's shareholders), of programs that are similar to those described above, and that could potentially influence or control the energy use of participating customers during peak periods. For example, the wide range of DSM options and measures that have been screened as part of the Company's integrated resource planning process included, for residential and/or commercial customers, the direct load control of central air conditioning, electric water heating, electric space heating and swimming pool water pumps.

AEP has also implemented DSM pilot programs on the direct load control of residential central air conditioning, electric water heating and electric space heating. An evaluation was conducted on a direct load control pilot program, for residential central air conditioning and water heating, implemented in 1994-1995 in another AEP jurisdiction. The results indicated that it would not be cost-effective to implement such a program for the AEP System, including KPCo.

Request No. 6

Response (cont'd)

A Load Management Water Heating Program has been implemented for residential customers in KPCo's service territory and across the AEP System. That program is designed to encourage customers to shift water heating energy use from on-peak periods to off-peak periods.

Also, KPCo offers Load Management/Time Of Day rates for residential service, medium general service, and for commercial and industrial power customers. These programs are also designed to influence customers to shift energy use from on-peak periods to off-peak periods.

Further, as discussed on pages 1-12 and 1-13 of KPCo's 1999 IRP Report, KPCo offers Tariff Riders for Emergency Curtailable Service (ECS) and Price Curtailable Service (PCS). These options provide for voluntary load curtailments by commercial and industrial customers who normally take firm service, with demands greater than 3 MW.

In addition, KPCo offers a Cogeneration and/or Small Power Production tariff for customers 100 kW or less (Tariff Cogen/SPP I), as well as for customers over 100 kW (Tariff Cogen/SPP II). These tariffs can enable the Company to use standby generation resources of potential participating commercial or industrial customers during peak load periods.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Second Request for Information
Dated February 8, 2000

Request No. 7:

Net metering has been instituted in some 30 states, and has been proposed to take effect on a national level through legislation titled the "Home Energy Policy Act," introduced by U.S. Representative Jay Inslee. Potential advantages of net metering include encouraging distributed generation, increasing the diversity of generation sources, reducing line losses, and reducing overall system costs if the customer-generator produces power during peak periods [e.g., a customer-owned photovoltaic system that produces at maximum output on a hot, sunny summer day].

a. If net metering were to be installed on a national or statewide level, what would be the estimated impact on energy use and demand in the KPCo service area over the next twenty years?

b. Has KPCo considered proposing a net metering policy or tariff?

Response:

a. The Company has not conducted a study to determine the impact of net metering on energy use and demand in the KPCo service area. Therefore, the requested information is not available.

b. KPCo's current Tariffs Cogen/SPP I and II contain net metering provisions as related to generation. Any new net metering tariffs or contracts that KPCo might propose in the future would likewise apply only to the generation portion of customer bills.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Kentucky Division of Energy's Second Request for Information
Dated February 8, 2000

Request No. 8:

To what extent has KPCo encouraged the installation of combined heat and power (cogeneration) systems by industrial firms in its service area? Please provide quantitative information if available.

Response:

KPCo neither encourages nor discourages the installation of combined heat and power (cogeneration) systems by industrial firms in its service territory. The decision by an industrial firm regarding whether to install a cogeneration system should be driven mainly by the costs required by the customer to install and operate such facilities versus the cost savings associated with the avoided purchases of power and the revenues the customer would receive from the Company's cogeneration tariff. To the extent that a customer expresses an interest, the Company will provide information, as appropriate, to assist the customer in evaluating and making decisions with respect to cogeneration.

Respondent: N. Tibberts

STITES & HARBISON

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January 24, 2000

RECEIVED
JAN 24 2000
PUBLIC SERVICE
COMMISSION

Mr. Martin Huelsmann
Executive Director
Public Service Commission
730 Schenkel Lane
Frankfort, KY 40601

RE: Case No. 99-437

Dear Mr. Huelsmann:

Please find enclosed and accept for filing an original and six (6) copies of American Electric Power's responses to the Attorney General's (1st Set) of data requests dated December 16, 1999, in Case No. 99-437.

If you have any questions, please let me know.

Very truly yours,

STITES & HARBISON

Judith A. Villines

Judith A. Villines

JAV:pjt
Enclosures

cc: Elizabeth E. Blackford, Esq.
Michael K. Kurtz, Esq.
Iris Skidmore, Esq.
Mr. Errol K. Wagner

RECEIVED

JAN 24 2000

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING	)	
REPORT OF KENTUCKY POWER COMPANY	)	**CASE NO. 99-437**
D/B/A AMERICAN ELECTRIC POWER COMPANY	)	

****

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

to

AG (1ST SET) DATA REQUESTS
DATED DECEMBER 16, 1999

FILED: JANUARY 24, 2000

INDEX

Attorney General's Initial Requests for Information

1. On page 1-1 of the IRP, reference is made to the need to add a Wyoming-Cloverdale 765-KV line. With respect to this planned addition:

a. Does any of this proposed line pass through Kentucky Power's service territory?

b. Will this project require a Certificate of Convenience and Necessity from the Public Service Commission of Kentucky? If so, when will the application be made?

c. Will Kentucky Power customers be charged for this new line in their rates? If yes, please indicate when and by what mechanism this charge will be added to rates.

2. With respect to the Rockport lease with Kentucky Power, discussed on page 1-9 of the IRP, please provide the following information for each of the last 5 years:

a. Amount of annual lease payment, and whether this amount will change if the agreement is renewed through 2004.

b. Number of kilowatt-hours produced by Kentucky Power's portion of the plant.

c. Number of kilowatt-hours produced, in part (b), that were actually used by Kentucky Power.

d. Number of kilowatt-hours produced, in part (b), that were sold to other AEP companies under the AEP Interconnection Agreement.

e. Number of kilowatt-hours produced, in part (b), that were sold to non-AEP affiliated companies.

f. Average fuel cost per kilowatt-hour.

g. Average non-fuel variable cost per kilowatt-hour.

h. Annual fixed O&M cost paid by Kentucky Power for its portion of the plant.

i. Total margin made in each given year for power from Kentucky Power's portion of Rockport sold to other AEP companies under the AEP Interconnection Agreement.

j. Total margin made in each given year for power from Kentucky Power's portion of Rockport sold to non-AEP affiliated companies.

k. If the Rockport lease agreement is not renewed in 2000 or 2005, what will AEP do with this capacity? Would not the capacity still be available to serve Kentucky Power under the AEP Interconnection Agreement?

3. On page 1-9 of the IRP reference is made to upcoming electric restructuring.

a. On December 15, 1999, the Kentucky Legislative Task Force on Electric Restructuring released its recommendation that Kentucky not pass any restructuring legislation during the next legislative session. Would Kentucky Power agree that there will be no electric restructuring in Kentucky in the near future and that Kentucky Power will continue under current regulation and will need to continue to plan to meet future load needs?

b. Please supply the status of any restructuring activities in each of the states in which AEP operates.

4. Table 5 on page 1-10 of the IRP shows that Kentucky Power, one of the smallest AEP companies, will be assigned the majority of the capacity 500 MW addition in 2005. Considering the lead time associated with building new capacity, including planning, is it the case that planning for this major addition to Kentucky Power's capacity will need to begin before Kentucky Power files its next IRP in 3 years.

5. On page 2-10 and 2-11 of the IRP, there is a discussion of how, when energy prices rise, customers respond by acting more energy efficiently. Nevertheless, the National Energy Policy Act of 1992 is being implemented during a period where electric prices are declining relative to inflation. Please explain in detail how your model can accommodate the reductions in energy use due to the National Energy Policy Act of 1992 when energy prices are declining.

6. Referring to Exhibit 2-30 in the IRP, please supply the actual data on this exhibit for calendar year 1999 for:

a. Kentucky Power Company's Recorded Summer Peak Load

b. Kentucky Power Company's Summer Peak Load - Weather Normalized

c. Kentucky Power Company's Recorded Winter Peak Load (through December 1999)

d. Kentucky Power Company's Winter Peak Load (through December 1999) - Weather Normalized

e. Kentucky Power Company's Recorded Energy

f. Kentucky Power Company's Energy - Weather Normalized

g. AEP System's Recorded Summer Peak Load

h. AEP System's Summer Peak Load - Weather Normalized

i. AEP System's Recorded Winter Peak Load (through December 1999)

j. AEP System's Winter Peak Load (through December 1999) - Weather Normalized

k. AEP System's Recorded Energy

l. AEP System's Energy - Weather Normalized

7. On page 3-7 of the IRP, it is stated that the evaluation Carbon Dioxide emissions was considered in the DSM evaluation. For each of the last 10 years, 1989-1999, please supply the following:

a. Total carbon dioxide emissions associated with supplying Kentucky Power's energy demand..

b. Total carbon dioxide emissions associated with supplying the internal energy demand for the total AEP System.

c. Total carbon dioxide emissions associated with supplying both the internal energy demand for the total AEP System and making off-system sales (AEP's total carbon dioxide emissions).

8. On page 3-7 of the IRP, it is stated that the evaluation Carbon Dioxide emissions was considered in the DSM evaluation. For each of the years in the IRP planning period, through 2019, and based on the plans in the IRP, please supply the following:

a. Total carbon dioxide emissions associated with supplying Kentucky Power's energy demand.

b. Total carbon dioxide emissions associated with supplying the internal energy demand for the total AEP System.

c. Total carbon dioxide emissions associated with supplying both the internal energy demand for the total AEP System and making off-system sales (AEP's total carbon dioxide emissions).

9. On page 4-8 of the IRP, reference is made to AEP subsidiaries' participation in the Ohio Valley Electric Corporation (OVEC). With respect to that participation, please supply the following:

a. Percent of participation and associated number of Megawatts for each of the 4 sponsoring AEP companies.

b. Number of Kilowatt-hours sold to OVEC by AEP for each of the last 5 years.

c. Number of Kilowatt-hours bought by OVEC from AEP for each of the last 5 years.

d. In December 1999, the United States Enrichment Corporation's President William Timbers stated that his company is "analyzing whether to shutting down one of its two production plants", and that upgrades were being made to the Paducah plant to match that capabilities of the Piketon plant. Has AEP included in the IRP the very real possibility that the Piketon plant may be shut down in the near future and that AEP's OVEC capacity may become available for AEP's use?

10. On page 4-15 of the IRP, coal and natural gas use is discussed. For each of the past 10 years 1989-1999, please supply:

a. Total tons of coal burned to supply Kentucky Power's energy demand.

b. Total tons of coal burned to supply the internal energy demand for the total AEP System.

c. Total tons of coal burned by AEP to supply both the internal energy demand for the total AEP System and make off-system sales.

d. Total MCF of natural gas burned to supply Kentucky Power's energy demand.

e. Total MCF of natural gas burned to supply the internal energy demand for the total AEP System.

f. Total MCF of natural gas burned by AEP to supply both the internal energy demand for the total AEP System and make off-system sales.

11. On page 4-15 of the IRP, coal and natural gas use is discussed. For each year of the IRP planning period (through 2019) and based on the plans in the IRP, please supply:

a. Total tons of coal projected to burned to supply Kentucky Power's energy demand.

b. Total tons of coal projected to burned to supply the internal energy demand for the total AEP System.

c. Total tons of coal projected to burned by AEP to supply both the internal energy demand for the total AEP System and make off-system sales.

d. Total MCF of natural gas projected to burned to supply Kentucky Power's energy demand.

e. Total MCF of natural gas projected to burned to supply the internal energy demand for the total AEP System.

f. Total MCF of natural gas projected to burned by AEP to supply both the internal energy demand for the total AEP System and make off-system sales.

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1

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Request for Information, First Set
Dated December 16, 1999

Request No. 1:

On page 1-1 of the IRP, reference is made to the need to add a Wyoming-Cloverdale 765-KV line. With respect to this planned addition:

a. Does any of this proposed line pass through Kentucky Power's service territory?

b. Will this project require a Certificate of Convenience and Necessity from the Public Service Commission of Kentucky?

c. Will Kentucky Power customers be charged for this new line in their rates? If yes, please indicate when and by what mechanism this charge will be added to rates.

Response:

a & b. No.

c. The total investment in the bulk transmission system (138 kV and above) of the AEP System is shared on a member-load-ratio (MLR) basis among the System's five major operating companies (Appalachian Power, Columbus Southern Power, Indiana Michigan Power, Kentucky Power and Ohio Power) in accordance with the FERC-approved AEP Transmission Agreement. Such costs, which are updated as new projects are completed, are normally reflected in the customer rates of each of these companies. In the case of Kentucky Power, the mechanism used for recovering such costs is the traditional rate-hearing process for seeking Commission approval for an increase in rates. This mechanism would also apply with respect to the recovery of the Company's MLR share of the investment in the Wyoming-Cloverdale line (or its alternative) following installation of that line, which is currently expected to be completed in the 2003-2004 time frame.

However, assuming that the AEP-CSW merger is consummated by the terms of the stipulation and settlement agreement relative to the merger, as approved by the Kentucky Public Service Commission in May 1999, absent a force majeure, the Company will not file a petition, which, if approved, would have the effect, either directly or indirectly, of authorizing a general increase in basic rates and charges that would be effective prior to January 1, 2003 or three years from the effective date of the merger, whichever is later.

Respondent: N. Tibberts

2

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Request for Information, First Set
Dated December 16, 1999

Request No. 2:

With respect to the Rockport lease with Kentucky Power, discussed on page 1-9 of the IRP, please provide the following information for each of the last 5 years:

a. Amount of annual lease payment, and whether this amount will change if the agreement is renewed through 2004.

b. Number of kilowatt-hours produced by Kentucky Power's portion of the plant.

c. Number of kilowatt-hours produced, in part (b), that were actually used by Kentucky Power.

d. Number of kilowatt-hours produced, in part (b), that were sold to other AEP companies under the AEP Interconnection Agreement.

e. Number of kilowatt-hours produced, in part (b), that were sold to non-AEP affiliated companies.

f. Average fuel cost per kilowatt-hour.

g. Average non-fuel variable cost per kilowatt-hour.

h. Annual fixed O&M cost paid by Kentucky Power for its portion of the plant.

i. Total margin made in each given year for power from Kentucky Power's portion of Rockport sold to other AEP companies under the AEP Interconnection Agreement.

j. Total margin made in each given year for power from Kentucky Power's portion of Rockport sold to non-AEP affiliated companies.

k. If the Rockport lease agreement is not renewed in 2000 or 2005, what will AEP do with this capacity? Would not the capacity still be available to serve Kentucky Power under the AEP Interconnection Agreement?

Request No.2

Response:

a. The annual lease payment is fixed at about $73.9 million throughout the life of the lease.

b. The energy produced by Kentucky Power's portion of the Rockport Plant for the period 1995-1999 was as follows:

1995 - 2,626 million kWh
1996 - 2,506
1997 - 2,560
1998 - 2,630
1999 - 2,488

c-e. The requested information is not available.

f-h. The requested costs for Kentucky Power's portion of the Rockport Plant for the period 1995-1999 were as follows:

	Average Fuel Cost (cents/kWh)	Estimated Average Non-Fuel Variable Cost (cents/kWh)	Estimated Annual Fixed O&M Cost (millions of $)
1995	1.1	0.06	23.5
1996	1.1	0.08	24.2
1997	1.2	0.07	24.3
1998	1.1	0.07	24.1
1999	1.1	0.07	21.7

i-j. The requested information is not available.

k. Under the terms of AEP Generating Company's Unit Power Service Agreement with Kentucky Power Company, at the end of the extension period (year-end 2004), Kentucky Power's 390-MW entitlement of Rockport Plant capacity shifts to Indiana Michigan Power Company. In the integrated resource plan, this capacity shift does not affect the total available capacity of the AEP System. However, under the terms of the existing AEP Interconnection Agreement, each member is required, to the extent practicable, to install or have available to it under contract such capacity as is necessary to supply all of the requirements of its own customers. See, AEP Generating Co. and Ky. Power Co., 38 FERC Par. 61,243 (1987).

Respondent: N. Tibberts

3

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Request for Information, First Set
Dated December 16, 1999

Request No. 3:

On page 1-9 of the IRP reference is made to upcoming electric restructuring.

a. On December 15, 1999, the Kentucky Legislative Task Force on Electric Restructuring released its recommendations that Kentucky not pass any restructuring legislation during the next legislative session. Would Kentucky Power agree that there will be no electric restructuring in Kentucky in the near future and that Kentucky Power will continue under current regulation and will continue to plan to meet future load needs?

b. Please supply the status of any restructuring activities in each of the states in which AEP operates.

Response:

a. Although Kentucky may not pass restructuring legislation in the near future, the move to increasing competition among suppliers in the marketplace, industry restructuring activities and customer choice initiatives in neighboring states will continue. AEP and each of its operating companies, doing business as AEP, will continue to operate in accordance with all applicable state and federal statutory and regulatory requirements.

b. See the accompanying Attachment 1, consisting of 2 pages, for the status of restructuring activities in each of the states in which AEP operates.

Respondent: N. Tibberts

STATUS OF ELECTRIC INDUSTRY RESTRUCTURING ACTIVITIES IN THE STATES IN WHICH AEP OPERATES

INDIANA

No restructuring legislation has been enacted.

KENTUCKY

No restructuring legislation has been enacted.

MICHIGAN

In 1998, the Michigan Public Service Commission issued a series of orders that unveiled its electric industry restructuring plan, which calls for a multi-step phase-in that would allow all customers to choose their electricity providers by January 1, 2002.

In March 1999, the Commission gave final approval to the retail choice implementation plans for Detroit Edison and Consumers Energy, establishing September 1999 as the start of the phase-in period for retail access. However, in June 1999, in response to a challenge by these two utilities and others of an earlier Commission-ordered retail wheeling pilot program, the Michigan Supreme Court ruled that the Commission lacks the authority to mandate such programs, but does have the authority to set transmission rates for wheeled power if a utility voluntarily chooses to offer direct retail access service.

In response to the court ruling, the two utilities said they would participate voluntarily in the state's restructuring program. Also, in August 1999, the Commission issued an order declaring it has the authority to implement its restructuring orders on a voluntary basis. However, a Michigan industrials group indicated its intention to appeal that order.

A draft restructuring bill is expected to be taken up in the Senate in the first quarter of 2000.

OHIO

On July 6, 1999, Ohio Governor Robert Taft signed the Ohio Electric Restructuring Act of 1999. The new law provides for customer choice of energy supplier beginning January 1, 2001, along with a 5% rate cut in the generation portion of residential customer bills. Rates would be frozen through a 5-year "market development period," after which, beginning on January 1, 2006, rates will be market-based.

TENNESSEE

In January 1999, the Tennessee Regulatory Authority submitted to Governor Sundquist a first report on the status of the electric utility industry in Tennessee, and on issues facing the state in light of the possible scenarios for regulatory and structural change. The report provided brief responses to six questions that the Special Joint Committee Studying Electric Utility Industry Deregulation, which was created in 1997, was charged to consider.

During the 1999 session of the Tennessee Legislature, a resolution was approved which continued the Special Joint Committee and requires a report from the Committee detailing its findings, recommendations and any proposed legislation by not later than February 28, 2001. Thus far, there has been no significant activity on the part of the Committee with respect to this matter.

VIRGINIA

In March 1999, the Virginia Electric Utility Restructuring Act of 1999 (SB1269) and a companion tax reform bill (SB1286) were signed into law by Virginia Governor James Gilmore. The new restructuring law provides for the transition to retail competition to begin by January 1, 2002 and end by January 1, 2004, when all customers will have choice of generation supplier. However, the Commission may delay the end date for specified reasons by as much as a year, but to no later than January 1, 2005.

WEST VIRGINIA

The debate on restructuring the electric utility industry in West Virginia began in May 1997, when the Public Service Commission of West Virginia authorized the establishment of a task force to study the issue. The task force issued a report in October 1997. Then in 1998, the West Virginia Legislature authorized the Commission to consider whether restructuring was in the public interest and, if so, to submit a plan for legislative approval. In April 1998, the Commission initiated a proceeding that resulted in a series of workshops to address specific issues associated with restructuring. In addition to the workshops, the Commission convened five separate public meetings throughout the State to take oral testimony on the issue of electric industry restructuring.

On December 20, 1999, the Commission issued an order that included a proposed transition plan to provide a competitive electricity market in West Virginia. Comments on the plan were filed on December 30, and a hearing on the plan was held on January 6 and 12, 2000.

The parties in the case, including AEP, continue to negotiate to reach a consensus on the Commission's proposed plan.

NT
January 2000

4

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Request for Information, First Set
Dated December 16, 1999

Request No. 4:

Table 5 on page 1-10 of the IRP shows that Kentucky Power, one of the smallest AEP companies, will be assigned the majority of the capacity 500 MW addition in 2005. Considering the lead time associated with building new capacity, including planning, is it the case that planning for this major addition to Kentucky Power's capacity will need to begin before Kentucky Power files its next IRP in 3 years?

Response:

Development of specific plans for new generation resources for Kentucky Power might - or might not - need to begin before the filing of the Company's next IRP Report with the Kentucky Public Service Commission.

As stated on page 1-1 of the IRP Report, the planning process is a continuous activity; assumptions and plans (both short-term and long-term) are being continually reviewed as new information becomes available, and are modified as appropriate. The resource expansion plan presented in the IRP Report reflects, to a large extent, assumptions that are subject to change. It is not a commitment to a specific course of action, since the future is highly uncertain, particularly in light of the move to increasing competition among suppliers in the marketplace and restructuring in the industry. Thus, the Company cannot state when the next resource commitment must be made.

Respondent: N. Tibberts

5

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Request for Information, First Set
Dated December 16, 1999

Request No. 5:

On page 2-10 and 2-11 of the IRP, there is a discussion of how, when energy prices rise, customers respond by acting more energy efficiently. Nevertheless, the National Energy Policy Act of 1992 is being implemented during a period where electric prices are declining relative to inflation. Please explain in detail how your model can accommodate the reductions in energy use due to the National Energy Policy Act when energy prices are declining.

Response:

As observed in the Company's discussion of conservation effects on pages 2-10 and 2-11 of the report, energy efficiency has been increasing since the energy price crisis of the mid-1970s, and this has reduced the rate of growth of energy usage during the period over which the forecast models are estimated. Therefore, this effect, of which the National Energy Policy Act of 1992 can be seen as a continuation, is already roughly reflected in the forecast results. In this regard, as noted on page 2-11 of the report, no explicit adjustments were made to the forecast to account for that Act.

The Company has recognized that real energy prices are likely to decline, as reflected in its assumption, stated on page 2-12, that "[t]hrough 2003, ... prices are expected to decline by the rate of inflation." The effect of this price decline on the forecast is reflected through the use of energy price variables in the long-term forecasting models.

Respondent: N. Tibberts

9

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Request for Information, First Set
Dated December 16, 1999

Request No. 6:

Referring to Exhibit 2-30 in the IRP, please supply the actual data on this exhibit for calendar year 1999 for:

a. Kentucky Power Company's Recorded Summer Peak Load

b. Kentucky Power Company's Summer Peak Load - Weather Normalized

c. Kentucky Power Company's Recorded Winter Peak Load (through December 1999)

d. Kentucky Power Company's Winter Peak Load (through December 1999) - Weather Normalized

e. Kentucky Power Company's Recorded Energy

f. Kentucky Power Company's Energy - Weather Normalized

g. AEP System's Recorded Summer Peak Load

h. AEP System's Summer Peak Load - Weather Normalized

i. AEP System's Recorded Winter Peak Load (through December 1999)

j. AEP System's Winter Peak Load (through December 1999) - Weather Normalized

k. AEP System's Recorded Energy

l. AEP System's Energy - Weather Normalized

Response:

The requested information is provided on the following page.

Request No. 6

Response (cont'd)

	1999 KPCo	1999 AEP System
A. Peak Load - Summer (MW)		
1. Recorded	1,215	19,952
2. Weather-Normalized	1,164	19,240
B. Peak Load - Winter Following (MW) [a][b]		
1. Recorded	1,312	17,353
2. Weather-Normalized	1,432	19,040
C. Energy (GWh) [a]		
1. Recorded	7,106	117,246
2. Weather-Normalized	7,157	117,274

Notes: [a] preliminary
[b] through December 1999

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Request for Information, First Set
Dated December 16, 1999

Request No. 7:

On page 3-7 of the IRP, it is stated that the evaluation Carbon Dioxide emissions was considered in the DSM evaluation. For each of the last 10 years, 1989-1999, please supply the following:

a. Total carbon dioxide emissions associated with supplying Kentucky Power's energy demand.

b. Total carbon dioxide emissions associated with supplying the internal energy demand for the total AEP System.

c. Total carbon dioxide emissions associated with supplying both the internal energy demand for the total AEP System and making off-system sales (AEP's total carbon dioxide emissions).

Response:

The total carbon dioxide emissions are not calculated, as requested, on an incremental basis. The total annual amounts of carbon dioxide emissions by AEP generating capacity during the period 1990-1999 are given in the table below. The listed emissions are associated with both supplying the internal energy demand of the AEP System and making off-system sales.

Year	AEP System CO_2 Emissions (Millions of Tons)	Year	AEP System CO_2 Emissions (Millions of Tons)
1990	107	1995	114
1991	100	1996	125
1992	107	1997	126
1993	103	1998	126.
1994	111	1999	120 (prelim.)

Respondent: N. Tibberts

8

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Request for Information, First Set
Dated December 16, 1999

Request No. 8:

On page 3-7 of the IRP, it is stated that the evaluation Carbon Dioxide emissions was considered in the DSM evaluation. For each of the years in the IRP planning period, through 2019, and based on the plans in the IRP, please supply the following:

a. Total carbon dioxide emissions associated with supplying Kentucky Power's energy demand.

b. Total carbon dioxide emissions associated with supplying the internal energy demand for the total AEP System.

c. Total carbon dioxide emissions associated with supplying both the internal energy demand for the total AEP System and making off-system sales (AEP's total carbon dioxide emissions).

Response:

The total carbon dioxide emissions are not calculated, as requested, on an incremental basis. The projected total annual amounts of carbon dioxide emissions by AEP generating capacity through the year 2013, the last year for which such figures are available, are given in the table that follows. The listed emissions are associated with both supplying the internal energy demand of the AEP System and making off-system sales.

The projections are based on the assumption that new generation resources, although currently undesignated, are all additions of gas-fired combustion turbine units.

Year	AEP System CO_2 Emissions (Millions of Tons)	Year	AEP System CO_2 Emissions (Millions of Tons)
2000	131	2007	141
2001	129	2008	144
2002	131	2009	142
2003	134	2010	142
2004	135	2011	140
2005	137	2012	140
2006	139	2013	139

Respondent: N. Tibberts

6

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Request for Information, First Set
Dated December 16, 1999

Request No. 9:

On page 4-8 of the IRP, reference is made to AEP subsidiaries' participation in the Ohio Valley Electric Corporation (OVEC). With respect to that participation, please supply the following:

a. Percent of participation and associated number of Megawatts for each of the 4 sponsoring AEP companies.

b. Number of Kilowatt-hours sold to OVEC by AEP for each of the last 5 years.

c. Number of Kilowatt-hours bought [from] OVEC by AEP for each of the last 5 years.

d. In December 1999, the United States Enrichment Corporation's President William Timbers stated that his company is "analyzing whether to shutting down one of its two production plants", and that upgrades were being made to the Paducah plant to match the capabilities of the Piketon plant. Has AEP included in the IRP the very real possibility that the Piketon plant may be shut down in the near future and that AEP's OVEC capacity may become available for AEP's use?

Response:

a. The participation rates for each of the 4 sponsoring AEP companies are as follows:

Appalachian Power Company	15.2%
Columbus Southern Power Company	4.3
Indiana Michigan Power Company	7.6
Ohio Power Company	15.0
Total	42.1%

The number of Megawatts associated with each of the above participation rates varies in accordance with the total magnitude of the power transaction (purchase/sale) between OVEC and the Sponsoring Companies.

Request No. 9

Response (cont'd)

b-c. Annual amounts of energy sold to, and bought from, OVEC by AEP for the period 1995-1999 are given in the table below.

Year	Millions of KWh Sold to OVEC	Millions of KWh Bought from OVEC
1995	10	824
1996	13	1,475
1997	8	1,880
1998	28	2,281
1999	78	2,233

d. For purposes of the IRP Report, the assumption was made that no surplus capacity would be available from OVEC for use by the Sponsoring Companies (including the participating AEP subsidiaries) throughout the forecast period. This reflects the assumption that the Piketon plant load would effectively be at "full contract quantity," i.e., the Piketon plant would be entitled to full use of OVEC capacity throughout the forecast period. As circumstances change, or are expected to change, with respect to the Piketon plant load (or, likewise, with respect to other specific load or capacity items), such changes would be taken into consideration in the resource planning process, and resource plans modified to the extent appropriate.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Request for Information, First Set
Dated December 16, 1999

Request No. 10:

On page 4-15 of the IRP, coal and natural gas use is discussed. For each of the past 10 years, please supply:

a. Total tons of coal burned to supply Kentucky Power's energy demand.

b. Total tons of coal burned to supply the internal energy demand for the total AEP System.

c. Total tons of coal burned by AEP to supply both the internal energy demand for the total AEP System and make off-system sales.

d. Total MCF of natural gas burned to supply Kentucky Power's energy demand.

e. Total MCF of natural gas burned to supply the internal energy demand for the total AEP System.

f. Total MCF of natural gas burned by AEP to supply both the internal energy demand for the total AEP System and make off-system sales.

Response:

a-c. The total tons of coal consumed are not calculated, as requested, on an incremental basis. The total annual amounts of coal consumed by AEP generating capacity during the period 1989-1999 are given in the table below. The coal was used to both supply internal energy demand and make off-system sales.

Year	AEP System Coal Consumption (Millions of Tons)	Year	AEP System Coal Consumption (Millions of Tons)
1989	45.0	1995	47.2
1990	46.2	1996	51.6
1991	43.3	1997	53.5
1992	46.6	1998	53.8
1993	44.9	1999	51.7 (prelim.)
1994	47.8		

Respondent: N. Tibberts

Request No. 10

Response (cont'd)

d-f. MCF figures are not calculated, as requested, on an incremental basis. The only natural gas consumed by AEP generating capacity during the period 1990-1999 totaled 941 thousand MCF (where 1 MCF = 1,000 cubic feet) in the year 1995. This amount is associated with supplying internal energy demand for the AEP System and making off-system sales.

Respondent: N. Tibberts

11

11

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Attorney General's Request for Information, First Set
Dated December 16, 1999

Request No. 11:

On page 4-15 of the IRP, coal and natural gas use is discussed. For each year in the IRP planning period (through 2019) and based on the plans in the IRP, please supply:

a. Total tons of coal projected to [be] burned to supply Kentucky Power's energy demand.

b. Total tons of coal projected to [be] burned to supply the internal energy demand for the total AEP System.

c. Total tons of coal projected to [be] burned by AEP to supply both the internal energy demand for the total AEP System and make off-system sales.

d. Total MCF of natural gas projected to [be] burned to supply Kentucky Power's energy demand.

e. Total MCF of natural gas projected to [be] burned to supply the internal energy demand for the total AEP System.

f. Total MCF of natural gas projected to [be] burned by AEP to supply both the internal energy demand for the total AEP System and make off-system sales.

Response:

The total tons of coal and MCF of natural gas projected to be consumed are not calculated, as requested, on an incremental basis. The total annual amounts of coal and gas projected to be consumed by AEP generating capacity through the year 2013, the last year for which such figures are available, are given in the table that follows. Such coal and gas would be used to both supply internal energy demand and make off-system sales.

The projections are based on the assumption that new generation resources, although currently undesignated, are all additions of gas-fired combustion turbine units.

Request No. 11

Response (cont'd)

Year	AEP System Coal Consumption (Millions of tons)	AEP System Gas Consumption (Million MCF)
2000	55.5	0
2001	54.7	0
2002	55.0	0
2003	56.3	0
2004	56.9	0
2005	57.2	12
2006	57.9	23
2007	58.4	31
2008	59.6	30
2009	57.5	106
2010	57.5	105
2011	55.9	123
2012	55.9	126
2013	54.8	159

Respondent: N. Tibberts

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RECEIVED
JAN 13 2000
PUBLIC SERVICE COMMISSION

January 13, 2000

Helen C. Helton
Executive Director
Kentucky Public Service Commission
730 Schenkel Lane
P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: Kentucky Public Service Commission Case No. 99-437

Dear Ms. Helton:

Enclosed for filing please find the original and six copies of American Electric Power's responses to the Commission's First Set of Data Requests pursuant to the Order dated December 9, 1999.

If you should have any questions please feel free to contact me.

Sincerely,

STITES & HARBISON

Bruce Clark

Bruce F. Clark

BFC:las
Enclosures

cc: Errol K. Wagner

KE057:KE115:3322:FRANKFORT

THE INTEGRATED RESOURCE
PLANNING REPORT OF KENTUCKY
POWER COMPANY D/B/A AMERICAN
ELECTRIC POWER

CASE NO. 99-437

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
TO
PSC STAFF (1ST SET) DATA REQUESTS
DATED DECEMBER 9, 1999

Filed: January 13, 2000

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLANNING	)	
REPORT OF KENTUCKY POWER COMPANY	)	CASE NO. 99-437
D/B/A AMERICAN ELECTRIC POWER COMPANY	)	

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RESPONSE OF KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

to

PSC STAFF (1ST SET) DATA REQUESTS
DATED DECEMBER 9, 1999

FILED: JANUARY 13, 2000

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COMMONWEALTH OF KENTCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INTEGRATED RESOURCE PLANNING REPORT OF KENTUCKY POWER COMPANY d/b/a AMERICAN ELECTRIC POWER TO THE KENTUKY PUBLIC SERVICE COMMISSION, OCTOBER, 1999	))))	CASE NO. 99-437

<u>COMMISSION STAFF'S REQUEST FOR INFORMATION TO KENTUCKY POWER COMPANY – AMERICAN ELECTRIC POWER</u>

The Commission Staff requests that an original and 6 copies of the following information be provided to the Staff, with a copy to all parties of record, by no later than the due date set out in the procedural schedule previously established for this case. Each copy of the data requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 5. Include with each response the name of the person responsible for responding to questions relating to the information provided.

1. Refer to page 1-2 of the Executive Summary of the Integrated Resource Planning ("IRP") Report of Kentucky Power Company ("KPC") and American Electric Power ("AEP") submitted October 21, 1999. Provide the current status of the regulatory approvals, in all jurisdictions, of the proposed merger of AEP and Central and South West Corporation ("CSW").

2. Identify and describe the manner in which the combined AEP-CSW system would be dispatched if and when, the merger receives final approval.

3. Refer to page 1-3 of the Executive Summary of the IRP report. Provide the current status of the unit power agreement with AEP Generating Company to purchase 390 megawatts of capacity from the Rockport Plant.

4. Refer to page 1-4 of the Executive Summary. Explain the reasons for the decision to switch from relying on the economic forecast performed by RDI to the forecast performed by RFA.

5. Refer to pages 1-4 and 1-5 of the Executive Summary. Identify all the factors that cause the forecast growth in demand for KPC to exceed that of the AEP system as a whole.

6. Refer to pages 1-11 and 1-12 of the Executive Summary. Provide a summary of the experience, to date, of any of the AEP operating companies regarding customers taking service under the ECS and PCS tariffs that were recently implemented.

7. Refer to page 2-1 of the Load Forecast section of the report. Explain the reason for using the 1998 regional economic forecast developed by Woods & Poole Economics, Inc. when KPC had previously performed this function in-house.

8. KPC and AEP use short-term and long-term models in their forecasting processes, with the short-term models covering the first 5 years of the forecast period. Explain the basis for choosing 5 years as the appropriate "short-term' period. Would applying the short-term models to a longer 'short-term' period of time be more costly?

9. Refer to pages 2-2 and 2-3 of the Load Forecast section of the report. Provide the results from the models used by KPC / AEP to predict sectoral natural gas prices and regional coal production as inputs to the long-term energy forecasts.

10. Refer to page 2-4 of the Load Forecast section of the report. Provide a more detailed description of the FRB production index used in the forecast for the industrial sector. Specifically identify the results that were used by KPC as inputs into its forecasting models.

11. Refer to page 2-8 of the Load Forecast section of the report. Given the areas of eastern and southeastern Kentucky included in KPC's service territory, explain why the Huntington, West Virginia weather station is the only point used by KPC to reflect weather effects in its forecasting.

12. Refer to page 2-9 of the Load Forecast section of the report, specifically the sentence that states that weather effects are assumed to be zero at an average daily temperature of 62 degrees. Many gas and electric utilities use 65 degrees as the average temperature at which weather effects are assumed to be zero. Provide an explanation of how and why KPC developed and uses 62 degrees for this purpose.

13. Refer to page 2-11 of the Load Forecast section. It is stated that the monthly short–term load forecasting models do not include variables such as the price of energy or per capita income, even though economic theory states that demand is always a function of price and income. Given this, answer the following:

    a) In general, what are the expected signs of the coefficients of the variables included in each of the short–term forecasting equations?

    b) Do the estimated coefficients obtained in the regression procedures (listed in the Appendix) accord with a priori expectations in terms of signs and statistical significance?

    c) Given that: (1) the estimation results possibly reflect omitted variable bias; (2) there exists some probability that electric restructuring will occur in Kentucky within the next five years, which could be contrary to the assumption that prices will be held constant in nominal terms.

Provide the results of a short-term energy requirements forecast that includes the price of electricity, real per capita incomes, and any other customer – specific information variables that would be relevant in specifying these demand equations.

14. Concerning the Long – term forecasting models:

a) Given the apparent autocorrelation that exists in some of the models (e.g., USE, EIM_KPC, EL_KPC), provide a re-estimation of the long–term forecasting equations using a procedure which corrects for such autocorrelation (such as Cochrane – Orcutt or Prais – Winston, given the small sample size).

b) Explain why is it assumed that (as stated on page 2-6) "in these cases, apparent autocorrelation is more likely a symptom of specific problems stemming from such causes as errors in data or omitted variables than of autocorrelation"?

c) Explain if the negatively – signed intercepts yielded by the estimation procedures cause for concern (since they appear to be highly statistically significant). Why or why not?

15. Refer to page 2-15 of the Load Forecast section of the report. Explain the reasons for modeling the industrial sector in aggregate rather than by major SIC code as has been done in prior IRPs.

16. Refer to Exhibit 2-28 of the report. Manufacturing and Mine Power customers both declined during the period from 1994 through 1998. Explain how this decline is reflected in the industrial sector forecast.

17. Refer to Exhibit 2-32. Provide the 'data source' documents identified therein that KPC / AEP obtained from NOAA, RFA, and DOE/EIA.

18. Refer to page 3-3 of the DSM section of the report. Provide a more detailed description of the EPA Green Lights Program identified therein.

19. Refer to page 3-4 of the DSM section of the report. Provide the survey that has been, or will be, distributed to customers, along with the number of KPC customers receiving the survey, the total number of AEP customers receiving the survey, and an explanation for how the sample size was determined.

20. Refer to page 3-7 of the DSM section of the report. If no specific dollar amounts were assigned to reductions to CO_2 and NO_x emissions, explain how those reductions were included in the evaluation of DSM programs.

21. Refer to page 3-8 of the DSM section of the report. Provide the level of participation by KPC's customers in the Load Management Water Heating Program to date and identify any load impacts that can be directly attributed to the program.

22. Refer to page 3-9 of the DSM section of the report. Explain how and why the measure-screening and program-screening processes were combined in the 1999 DSM screening rather than being performed separately as has been done in prior screenings.

23. Refer to page 3-10 of the DSM section of the report, specifically Paragraph H.2. Provide a more thorough description and explanation of how increasing competition might affect DSM in the future and why the emphasis in future evaluations would be more from a ratepayer perspective than from a societal perspective.

24. Refer to page 4-6 of the Resource Forecast section of the report. Provide an explanation for the determination by AEP that a satisfactory level of capacity-deficient days is between 5 and 10% of the number of days in a year.

25. Refer to page 4-6 of the Resource Forecast section of the report. Provide support for the projection that AEP's average on-peak equivalent availability will be 80% or better during the forecast period. Provide the comparable equivalent availability data for the AEP system for the 10-year period from 1989 through 1998.

26. Refer to page 4-7 of the Resource Forecast section of the report. Provide a detailed explanation for the assumption that the unit power agreement between KPC and AEP Generating Company will expire at the end of 2004. Identify the factors that might lead to the contract being extended beyond 2004.

27. Refer to page 4-11 of the Resource Forecast section of the report, specifically the section dealing with non-utility generation. To what extent is KPC familiar with plans by Dynegy Corp. to construct a merchant plant near the site of its Big Sandy Generating Station? What consideration has been given to the potential construction of that plant?

28. Refer to page 4-15 of the Resource Forecast section of the report, specifically the statement that indicates that most of AEP's total coal requirements are obtained under long-term arrangements. Explain or define what is meant by 'most' and provide the split between contract and spot market purchases for the AEP system for each of the years from 1994 through 1998.

29. Refer to pages 4-15 and 4-16 of the Resource Forecast section of the report. Identify which of the AEP generating units have been modified in order to be dual-fuel capable as part of AEP's compliance plan.

30. Refer to Exhibit 4-10 of the report. The Big Sandy station has the lowest average production costs of all AEP generating capacity. Given the central dispatching of the AEP system, identify how much of KPC's load and energy requirements are served from KPC's own Big Sandy generating station.

31. Refer to Exhibit 4-10 of the report and KPC's firm purchases of energy from the Rockport plant as shown in Exhibit 4-23. Identify where the Big Sandy station and the Rockport station fall in the order of dispatch for the AEP system. Identify how much energy KPC is required to purchase under the unit power agreement on an annual basis. Explain how the determination is made as to what energy will be sold off-system and what energy will go toward serving KPC's native load customers.

32. Refer to Exhibit 4-11 of the report. Explain the basis for the different life expectancies (50 years, 60 years, and 70 years0) shown for the different generating units identified in the exhibit.

33. Refer to Exhibit 4-25 of the report which compares the AEP system's 1996 and 1999 expansion plans. Identify the factors that have contributed to the decrease in the amount of capacity expected to be added through 2016.

34. Refer to page 2 of the Appendix regarding Short-Term Energy Models. Explain why there are only two exogenous variables for cooling degree-days and three exogenous variables for heating degree-days.

35. Refer to page 62 of the Appendix showing residential customers, actual and forecast. For the period 1989 through 1998 the growth in the number of customers has averaged approximately 1.05%. Identify the factors that led to the forecast growth of only .8 to .9% and explain how those factors were used to produce the forecast growth rate.

36. Page 74 of the Appendix shows exogenous variables for the commercial sector. Given the similarities that residential and commercial customers have regarding temperature-sensitive load, explain why there are no temperature-sensitive variables for the commercial sector.

37. Refer to pages 90 and 91 of the Appendix that show the exogenous variables for the Mine Power sector. Service area coal production has remained almost flat over the period from 1989 through 1998. Identify the factors that support the forecasted increase in service area production and explain how those factors were used to derive the forecasted increase. Also, explain how the forecasted increase in service area mine production comports with the statement on page 2-14 of the report that references the continued shift of production from eastern to western states.

Respectively submitted,

Richard G. Raff
Staff Attorney

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Request for Information, First Set
Dated December 9, 1999

Request No. 1:

Refer to page 1-2 of the Executive Summary of the Integrated Resource Planning ("IRP") Report of Kentucky Power Company ("KPC") and American Electric Power ("AEP") submitted October 21,1999. Provide the current status of the regulatory approvals, in all jurisdictions, of the proposed merger of AEP and Central and South West Corporation ("CSW").

Response:

Regulatory approvals of the proposed AEP-CSW merger have been received, as required, in all four states served by CSW, i.e., Arkansas, Louisiana, Oklahoma and Texas.

Although it is AEP's position that regulatory approvals of the merger are not required in the states served by AEP, settlement agreements with AEP have been approved by the utility commissions in those states in which agreements were sought on matters pertinent to the merger, including the sharing of merger savings. Such agreements were reached in Indiana, Kentucky and Michigan.

In addition, the Nuclear Regulatory Commission approved a license transfer application related to the merger. The Federal Communications Commission (FCC) is expected to approve license transfers in the February-March 2000 time frame.

The merger also requires approval of the Federal Energy Regulatory Commission (FERC) and the Securities and Exchange Commission (SEC), and clearance by the Department of Justice (DOJ). The FERC indicated it will act on the merger no later than February-March 2000. The SEC review will follow the FERC's action, and DOJ clearance is expected soon.

Respondent: N. Tibberts

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Request for Information, First Set
Dated December 9, 1999

Request No. 2:

Identify and describe the manner in which the combined AEP-CSW system would be dispatched if and when the merger receives final approval.

Response:

The generating resources of the combined AEP-CSW system will be centrally dispatched. Such central dispatch will commence on the first day of operation of the combined system.

It is the intent of AEP and CSW, when and as practicable, to combine the control area functions of the east zone and the west zone, corresponding to the pre-merger AEP and CSW systems, respectively. The combined system dispatch will be conducted on a least-cost basis, subject to the availability of transmission entitlements linking the AEP and CSW control areas.

The control areas will be centrally dispatched in real time to minimize total generation costs for the combined system, subject to any transmission constraints. Also subject to these constraints, unit commitment will be performed to meet the combined system's obligations, taking into account the specific obligations within each control area.

It is also the intent of AEP and CSW, following the merger, to investigate the combining of the dispatch centers at one location to reduce operation costs.

Respondent: N. Tibberts

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Request for Information, First Set
Dated December 9, 1999

Request No. 3:

Refer to page 1-3 of the Executive Summary of the IRP report. Provide the current status of the unit power agreement with AEP Generating Company to purchase 390 megawatts of capacity from the Rockport Plant.

Response:

The unit power agreement that governs Kentucky Power's 390-MW capacity purchase from the Rockport Plant provides for an automatic 5-year extension of the agreement's original expiration date of December 31, 1999 (i.e., to December 31, 2004) unless Kentucky Power gives at least 12 months' prior notice (i.e., by December 31, 1998) to the other parties to the agreement (Indiana Power Company and AEP Generating Company). Inasmuch as no such notice was given, the agreement will continue to be in effect through year 2004.

Respondent: N. Tibberts

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Request for Information, First Set
Dated December 9, 1999

Request No. 4:

Refer to page 1-4 of the Executive Summary. Explain the reasons for the decision to switch from relying on the economic forecast performed by [DRI] to the forecast performed by RFA.

Response:

The DRI forecasting service was significantly more expensive than the RFA forecasting service. Also, the Company adjudged the DRI forecasting service to be of similar or lower quality to that provided by RFA.

Respondent: N. Tibberts

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Request for Information, First Set
Dated December 9, 1999

Request No. 5:

Refer to pages 1-4 and 1-5 of the Executive Summary. Identify all the factors that the forecast growth in demand for KPC to exceed that of the AEP System as a whole.

Response:

The AEP forecast was affected by significant reductions in load due to certain sales-for-resale customers and a large industrial customer indicating that they would seek bids from alternative energy sources when their respective contracts expired. There were no such customers in the KPCo service area. In addition, KPCo energy sales (in the residential and commercial sectors, in particular) have historically grown at a pace faster than the AEP System as a whole, and this trend was expected to continue.

Respondent: N. Tibberts

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Request for Information, First Set
Dated December 9, 1999

Request No. 6:

Refer to pages 1-11 and 1-12 of the Executive Summary. Provide a summary of the experience, to date, of any of the AEP operating companies regarding customers taking service under the ECS and PCS tariffs that were recently implemented.

Response:

Customers of Wheeling Power Company and Appalachian Power Company have a total of 50 to 96 MW subject to price curtailable provisions comparable to those covered by Kentucky Power's Rider PCS. A range of MW is specified because some customers guarantee a minimum MW amount, but will provide additional MW if possible. In 1999, Ohio Power Company also had 45 MW subject to the provisions of Rider PCS.

Respondent: N. Tibberts

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KENTUCKY POWER COMPANY
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Dated December 9, 1999

Request No. 7:

Refer to page 2-1 of the Load Forecast section of the report. Explain the reason for using the 1998 regional economic forecast developed by Woods & Poole Economics, Inc. when KPC had previously performed this function in-house.

Response:

The switch from an AEP-produced regional economic forecast to one produced by Woods & Poole was a change that affected all AEP operating company forecasts, not only that of Kentucky Power. Producing an independent regional economic forecast is relatively costly, while the Woods & Poole forecast is relatively inexpensive to obtain. Upon examining the Woods & Poole results on a provisional basis, it was adjudged that they were sufficiently reasonable to warrant substituting them for a more costly forecast produced in-house.

Respondent: N. Tibberts

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Request for Information, First Set
Dated December 9, 1999

Request No. 8:

KPC and AEP use short-term and long-term models in their forecasting processes, with the short-term models covering the first five years of the forecast period. Explain the basis for choosing 5 years as the appropriate "short-term" period. Would applying the short-term models to a longer "short-term" period of time be more costly?

Response:

The decision to accept the results of the short-term models up to five years ahead, and to allow the results of the long-term models to affect the forecast at longer horizons, was based largely on an appreciation of how these two sets of models perform and the costs of doing forecasts at different horizons.

Within a comparatively short forecast horizon, the effects of expected changes in energy prices and regional economic growth on load growth can generally be omitted from the explicit analysis and treated implicitly through the application of time trends. Expected changes in prices are essentially never sufficiently sudden or of sufficient size to cause load growth to deviate much from recent trends, particularly considering that the short-term response to price is generally slight. (In this regard, as explained on pages 2-11 and 2-12 of KPCo's IRP report, the response to a given, one-time change in price increases as time passes.) Also, while the analogous response of load to short-term regional economic changes is not slight, sudden or dramatic changes are, still, virtually never expected in the growth of the regional economy.

In the longer-term, the response of load to price is greater than for the short term. Also, the growth trends for price and the regional economy are much less likely to resemble simple time trends. For this reason, long-term forecasting models must take explicit account of prices and regional economic variables. This, in turn, complicates long-term forecasting and ensures that it is more troublesome and expensive than short-term forecasting.

On the other hand, compared to the long-term expectation for load growth, the short-term expectation is much more likely to be affected by recent changes in outlook. Variations in the business cycle, for example, will generally have a significant effect on year-ahead expected load without having much effect on the load expected ten years ahead.

Request No. 8

Response (cont'd)

It was, therefore, considered prudent and cost-effective to have in place a set of short-term forecasting models that, given a year's worth of new data and possible new information on business cycle developments, could produce a new forecast inexpensively and without necessarily engaging the more complicated and expensive long-term forecasting apparatus. It was also considered desirable to allow the short-term results to run as far as time trends could reasonably be relied upon to substitute for structural economic effects. In this regard, based upon the experience with respect to historical loads, five years was adjudged to be reasonable for accepting purely short-term results. Nevertheless, if dramatic changes in price or regional economic activity were ever expected within the five-year short-term forecasting horizon, this decision would likely be revised.

The application of the short-term models to a longer "short-term" period would not be more costly. If anything, it would be less costly in terms of the trouble and expense of preparing the forecast. However, the quality of the results beyond five years would be degraded to the extent that the effects of changes in prices and regional economic activity, at that longer horizon, would fail to resemble simple time trends in load growth.

Respondent: N. Tibberts

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Request for Information, First Set
Dated December 9, 1999

Request No. 9:

Refer to pages 2-2 and 2-3 of the Load Forecast section of the report. Provide the results from the models used by KPC/AEP to predict sectoral natural gas prices and regional coal production as inputs to the long-term energy forecasts.

Response:

See the accompanying Attachment 1, which provides the estimation results of the model used to forecast coal production for the Kentucky Power Company service area.

Attachment 2, consisting of 4 pages, provides the estimation results of the model used to forecast the State of Kentucky natural gas prices for the residential, commercial, industrial and electric utility sectors.

Respondent: N. Tibberts

KENTUCKY POWER COMPANY
SERVICE AREA COAL PRODUCTION
MODEL ESTIMATION

SYSLIN Procedure
Ordinary Least Squares Estimation

Model: QC_KY
Dependent variable: QC_KY SERVICE AREA COAL PRODUCTION

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Prob>F
Model	5	4487565614.3	897513122.86	92.758	0.0001
Error	17	164489856.79	9675873.9286		
C Total	22	4652055471.1			

Root MSE	3110.60668	R-Square	0.9646
Dep Mean	89586.61643	Adj R-SQ	0.9542
C.V.	3.47218		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	T for H0: Parameter=0	Prob > |T|	Variable Label
INTERCEP	1	16460	7886.833585	2.087	0.0523	Intercept
PRODUS	1	0.006214	0.025659	0.242	0.8115	U.S. COAL PRODUCTION
CCELEC	1	0.103444	0.024208	4.273	0.0005	U.S. ELECTRIC UTILITY COAL CONSUMPTION
D83	1	-14597	3593.821351	-4.062	0.0008	BINARY VARIABLE - 1983
D88	1	-7426.870701	3291.951971	-2.256	0.0375	BINARY VARIABLE - 1988
D95ON	1	-11455	2321.201429	-4.935	0.0001	BINARY VARIABLE - 1995 ON

Durbin-Watson	1.986
(For Number of Obs.)	23
1st Order Autocorrelation	-0.002

STATE OF KENTUCKY
RESIDENTIAL PRICE OF NATURAL GAS
MODEL ESTIMATION

SYSLIN Procedure
Ordinary Least Squares Estimation

Model: PR_KY
Dependent variable: PR_KY KY RES. GAS PRICE, 1982 $/MCF

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Prob>F
Model	2	67.78683	33.89342	1956.945	0.0001
Error	22	0.38103	0.01732		
C Total	24	68.16786			

Root MSE	0.13160	R-Square	0.9944
Dep Mean	3.94880	Adj R-SQ	0.9939
C.V.	3.33275		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	T for H0: Parameter=0	Prob > |T|	Variable Label
INTERCEP	1	-0.318196	0.075381	-4.221	0.0004	Intercept
GPRF_US	1	0.901834	0.015658	57.595	0.0001	US RES. GAS PRICE, 1982 $/MCF
D95ON	1	0.197377	0.086700	2.277	0.0329	BINARY VARIABLE - 1995 ON

Durbin-Watson	1.327
(For Number of Obs.)	25
1st Order Autocorrelation	0.147

STATE OF KENTUCKY
COMMERCIAL PRICE OF NATURAL GAS
MODEL ESTIMATION

SYSLIN Procedure
Ordinary Least Squares Estimation

Model: PC_KY
Dependent variable: PC_KY KY COM. GAS PRICE, 1982 $/MCF

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Prob>F
Model	2	60.07671	30.03836	1970.881	0.0001
Error	22	0.33530	0.01524		
C Total	24	60.41202			

Root MSE	0.12345	R-Square	0.9944
Dep Mean	3.67440	Adj R-SQ	0.9939
C.V.	3.35986		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	T for H0: Parameter=0	Prob > |T|	Variable Label
INTERCEP	1	-0.293922	0.069321	-4.240	0.0003	Intercept
GPCF_US	1	0.971804	0.016550	58.721	0.0001	US COM. GAS PRICE, 1982 $/MCF
D95ON	1	0.202941	0.080081	2.534	0.0189	BINARY VARIABLE - 1995 ON

Durbin-Watson	1.205
(For Number of Obs.)	25
1st Order Autocorrelation	0.224

STATE OF KENTUCKY
INDUSTRIAL PRICE OF NATURAL GAS
MODEL ESTIMATION

SYSLIN Procedure
Ordinary Least Squares Estimation

Model: PI_KY
Dependent variable: PI_KY KY IND. GAS PRICE, 1982 $/MCF

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Prob>F
Model	3	38.72205	12.90735	811.320	0.0001
Error	21	0.33409	0.01591		
C Total	24	39.05614			

Root MSE	0.12613	R-Square	0.9914
Dep Mean	2.98680	Adj R-SQ	0.9902
C.V.	4.22295		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	T for H0: Parameter=0	Prob > |T|	Variable Label
INTERCEP	1	-0.210438	0.070160	-2.999	0.0068	Intercept
GPIF_US	1	1.118625	0.025939	43.126	0.0001	US IND. GAS PRICE, 1982 $/MCF
D86ON	1	0.432377	0.056992	7.587	0.0001	BINARY VARIABLE - 1986 ON
D95ON	1	0.006088	0.084353	0.072	0.9431	BINARY VARIABLE - 1995 ON

Durbin-Watson	1.834
(For Number of Obs.)	25
1st Order Autocorrelation	-0.041

STATE OF KENTUCKY
ELECTRIC UTILITY PRICE OF NATURAL GAS
MODEL ESTIMATION

SYSLIN Procedure
Ordinary Least Squares Estimation

Model: PU_KY
Dependent variable: PU_KY KY UTIL. GAS PRICE, 1982 $/MCF

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Prob>F
Model	4	25.99462	6.49865	180.319	0.0001
Error	20	0.72080	0.03604		
C Total	24	26.71542			

Root MSE	0.18984	R-Square	0.9730
Dep Mean	2.46440	Adj R-SQ	0.9676
C.V.	7.70336		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	T for H0: Parameter=0	Prob > |T|	Variable Label
INTERCEP	1	-0.064266	0.102501	-0.627	0.5378	Intercept
GPUF_US	1	0.993948	0.042048	23.639	0.0001	US UTIL. GAS PRICE, 1982 $/MCF
D86ON	1	0.528676	0.086172	6.135	0.0001	BINARY VARIABLE - 1986 ON
D94ON	1	0.363023	0.128541	2.824	0.0105	BINARY VARIABLE - 1994 ON
D97ON	1	-0.280428	0.220137	-1.274	0.2173	BINARY VARIABLE - 1997 ON

Durbin-Watson	1.904
(For Number of Obs.)	25
1st Order Autocorrelation	0.039

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Request for Information, First Set
Dated December 9, 1999

Request No. 10:

Refer to page 2-4 of the Load Forecast section of the report. Provide a more detailed description of the FRB production index used in the forecast for the industrial sector. Specifically identify the results that were used by KPC as inputs into its forecasting models.

Response:

The FRB production index used in the short-term manufacturing energy sales models is the production index for basic steel (SIC 331). The data used in the model are provided on pages 26 and 27 of the Appendix of the report.

Respondent: N. Tibberts

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
KPSC Case No. 99-437
1999 Integrated Resource Planning Report to the KPSC

Commission Staff's Request for Information, First Set
Dated December 9, 1999

Request No. 11:

Refer to page 2-8 of the Load Forecast section of the report. Given the areas of eastern and southeastern Kentucky included in KPC's service territory, explain why the Huntington, West Virginia station is the only point used by KPC to reflect weather effects in its forecasting.

Response:

The Huntington, West Virginia weather station, located at the Huntington-Ashland airport, is the nearest to the Kentucky Power service area whose observations are easily obtainable and highly reliable. However, for load forecasting purposes, the choice of using weather data from this station, rather than from other weather stations, has no practical effect on the forecast. While differences in weather between Huntington-Ashland and, say, Jackson or Pikeville, Kentucky may be significant on an hourly basis, such differences are only slight on a daily basis and insignificant on a monthly or seasonal basis. For monthly and longer intervals, the weather is strongly correlated throughout, and even far beyond, the Company's service area. For example, an exceptionally hot July is essentially never experienced at Huntington-Ashland without also being experienced at Pikeville. Although the weather that constitutes an exceptionally hot July at Huntington-Ashland would normally be somewhat hotter than the equivalent weather at Pikeville, such systematic differences between the actual weather in the Company's service area and the measured weather at the station used for modeling are implicitly accounted for when the coefficients of the forecasting model are estimated. Indeed, it would be of little significance if the models were estimated with weather measured at Pittsburgh, Pennsylvania; Columbus, Ohio; or Covington, Kentucky, since the weather at each of these stations, and at many other weather stations in the upper Ohio Valley, is strongly correlated with the Huntington-Ashland weather.

Respondent: N. Tibberts

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Request No. 12:

Refer to page 2-9 of the Load Forecast section of the report, specifically the sentence that states that weather effects are assumed to be zero at an average daily temperature of 62 degrees. Many gas and electric utilities use 65 degrees as the average temperature at which weather effects are assumed to be zero. Provide an explanation of how and why KPC developed and uses 62 degrees for this purpose.

Response:

The peak demand model referred to on page 2-9 of KPCo's IRP report makes use of a continuous, piecewise linear weather-response function. Estimation of such a function requires the analyst to specify the temperatures at which the nodes, or "kinks," of this function should be. Among these is the principal node, at which the weather response is assumed to be zero, and which divides the heating response from the cooling response. In the case of KPCo, the location of the principal node was determined to be at 62 degrees, and the other nodes determined to be at 32 and 72 degrees. These nodes, which were determined by a process of trial and error, provided the best fit with the historical data. In any case, the location of the principal node of the weather-response function, whether at 62 degrees or 65 degrees, is of little practical consequence on the results of the forecast.

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Request No. 13:

Refer to page 2-11 of the Load Forecast section. It is stated that the monthly short-term load forecasting models do not include variables such as the price of energy or per capita income, even though economic theory states that demand is always a function of price and income. Given this, answer the following:

a) In general, what are the expected signs of the coefficients of the variables included in each of the short-term forecasting equations?

b) Do the estimated coefficients obtained in the regression procedures (listed in the Appendix) accord with a priori expectations in terms of signs and statistical significance?

c) Given that: (1) the estimation results possibly reflect omitted variable bias; (2) there exists some probability that electric restructuring will occur in Kentucky within the next five years, which could be contrary to the assumption that prices will be held constant in nominal terms, provide the results of a short-term energy requirements forecast that includes the price of electricity, real per capita incomes, and any other customer-specific variables that would be relevant in specifying these demand equations.

Response:

a) No particular sign is expected for the intercept, or for any of the binary variables or time trends. Nor is any particular sign expected for the weather terms in the models other than residential, commercial and municipal (municipal load is assumed to be largely residential in character). In the residential, commercial and municipal models, the expectation for the weather terms is a joint one, since these estimated coefficients together describe a polynomial weather-response function versus monthly average temperature. The prior expectation is that when graphed, this function will look very roughly U-shaped with a minimum at 65 degrees (this condition is satisfied by the estimated residential and commercial coefficients). The sign on the FRB production index for basic steel, in the manufacturing energy model, is expected to be positive.

Request No. 13

Response (cont'd)

b) With regard to signs, the estimated coefficients do accord with a priori expectations. However, there was no a priori expectation with regard to the statistical significance of any coefficient; nor was any particular level of confidence applied as an inflexible determinant of whether a variable or group of variables should remain in any given model. In general, within each model, a joint test of significance of monthly binaries, and likewise of all weather terms and time trends, revealed significance at a high confidence level. The coefficient for the FRB production index for basic steel, in the manufacturing energy model, is readily seen to be significant at a high level of confidence.

c) Such a short-term energy requirements forecast has not been developed and, therefore, the requested results are not available.

Respondent: N. Tibberts

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Request No. 14:

Concerning the long-term forecasting models:

a) Given the apparent autocorrelation that exists in some of the models (e.g., USE, EIM_KPC, EL_KPC), provide a re-estimation of the long-term forecasting equations using a procedure which corrects for such autocorrelation (such as Cochrane-Orcutt or Prais-Winston, given the small sample size).

b) Explain why is it assumed that (as stated on page 2-6) "in these cases, autocorrelation is more likely a symptom of specific problems stemming from such causes as errors in data or omitted variables than of autocorrelation"?

c) Explain if the negatively-signed intercepts yielded by the estimation procedures [are] cause for concern (since they appear to be highly statistically significant). Why or why not?

Response:

a) The requested re-estimation has never been developed and, therefore, cannot be provided. The models already reported represent the Company's best good-faith effort to provide a reliable load forecast.

b) There is scant basis in economic theory or in practical experience for hypothesizing that annual electric loads exhibit an autocorrelated error process. Experience working with annual loads and economic time series does, however, often reveal problems with errors in data and omitted variables. A low Durbin-Watson statistic is a well-known symptom, not only of the pure autocorrelation that the statistic was designed to detect, but also of specification problems such as omitted variables. In the context of the set of models under discussion, it is the latter problem, not the former, to which the low Durbin-Watson statistics very likely point. However undesirable this problem may be, unless additional data can be obtained, it has to be lived with.

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Request No. 14

Response (cont'd)

c) The sign of the intercept term in these models is without significance for the forecast. The estimated coefficient on the intercept in a linear regression model is merely the means by which the regression line adjusts to the arbitrary scale of the independent variables. If, for example, an arbitrary constant is added to any independent variable, the estimated coefficient on that variable remains the same (and so does its statistical significance), while the intercept's coefficient changes to produce the identical predicted values of the dependent variable. In any case, the predicted values of the dependent variable are determined by the independent variables jointly, not by any variable or term (such as the intercept) alone. In the models reported, there is no historical or forecast observation for which the predicted values of load are implausible. As stated in the response to Request 13a, this set, there is no expectation for the sign of any intercept term.

Respondent: N. Tibberts

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Request No. 15:

Refer to page 2-15 of the Load Forecast section of the report. Explain the reasons for modeling the industrial sector in aggregate rather than by major SIC code as has been done in prior IRPs.

Response:

The Company no longer models manufacturing sales by SIC, as it currently has little need for forecasts by SIC. In addition, modeling the manufacturing sector in aggregate provides greater efficiency for the modeling efforts.

Respondent: N. Tibberts

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Request No. 16:

Refer to Exhibit 2-28 of the report. Manufacturing and Mine Power customers both declined during the period from 1994 through 1998. Explain how this decline is reflected in the industrial sector forecast.

Response:

The industrial sector forecast is for energy sales, not for the number of manufacturing or mining customers. The industrial customers are not homogeneous and their effects on energy are likewise not homogeneous. For example, a decline in the number of industrial customers may be accompanied by a substantial increase in industrial energy sales, if a large number of small customers are lost, while during the same time period a small number of large customers are added. Therefore, the effect of the change in the number of industrial customers was not taken into consideration in the development of the industrial forecast.

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Request No. 17:

Refer to Exhibit 2-32. Provide the 'data source' documents identified therein that KPC/AEP obtained from NOAA, RFA, and DOE/EIA.

Response:

The data were not obtained in printed form, but from the websites of the relevant sources. The RFA website is www.rfa.com. DOE/EIA data are publicly available at www.eia.doe.gov, and NOAA data are available at www.nws.noaa.gov. Of course, all the data input to the forecast has already been supplied in the Appendix section of the IRP report.

Respondent: N. Tibberts

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Request No. 18:

Refer to page 3-3 of the DSM section of the report. Provide a more detailed description of the Green Lights Program identified therein.

Response:

The Green Lights Program is a voluntary non-regulatory program sponsored by the U.S. EPA. The purpose this program is to encourage major U.S. corporations to install energy-efficient lighting technologies wherever they are profitable, and maintain or improve lighting quality. In 1992, AEP joined the Green Lights Program as a Utility Alley and signed a Memorandum of Understanding to implement the program. As a Utility Alley, AEP agreed to :

- survey the lighting in all of its facilities;
- consider a full range of lighting options to reduce energy use;
- complete energy-efficient lighting upgrades at 90% of the square footage of the facilities wherever profitable while maintaining or improving lighting quality;
- complete retrofit within 5 years of signing the agreement;
- assist EPA in marketing the benefits of Green Lights and energy-efficient lighting technologies to industrial and commercial customers;
- assist EPA in documenting the savings from energy-efficient lighing upgrades it makes.

In the implementation of the program, the facilities that received lighting upgrades included offices, stores/shops, service centers, substations and power plants, spanning all jurisdictions of AEP System, including Kentucky. The more efficient lighting technologies installed include T-8 lamps, electronic ballasts, compact fluorescent lamps, occupancy sensors, and HID lights, such as Metal Halide and High Pressure Sodium lamps. The program was successfully completed within the 5-year time frame.

Respondent: N. Tibberts

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Request No. 19:

Refer to page 3-4 of the DSM section of the report. Provide the survey that has been, or will be, distributed to customers, along with the number of KPC customers receiving the survey, the total number of AEP customers receiving the survey, and an explanation for how the sample size was determined.

Response:

The Company is still in the process of designing the survey questionnaire that was originally intended to be distributed to residential customers in late 1999. The survey will consist of questions similar to those asked in the previous (1996) survey, but will add a few more questions relating to home computers, home entertainment and telecommunication equipment. Since the design of the survey has not been completed, the number of AEP customers, including KPCo customers, anticipated to receive the survey is not known at this time. In 1996, about 41,000 survey questionnaires were mailed to AEP customers; about 3,400 of these questionnaires were mailed to KPCo customers. A copy of that 1996 survey questionnaire is provided herein as Attachment 1.

These surveys are designed to obtain statistically valid estimates of population saturation percentages, as well as saturation percentages for selected cross-classifications, for each distribution region of the AEP System. The determination of the required sample size involves a two-step procedure. First, the initial sample size is determined by the criterion that the estimated population saturation at the divisional level should not differ from the actual population saturation by more than 4% at the 95% confidence level. Second, anticipating an expected response rate of about 50%, the initial sample size estimated in the first step is doubled.

STAFF Set 1
Item No. 19
Attachment 1
(4 pages)

1996 CUSTOMER SURVEY

AEP AMERICAN ELECTRIC POWER

Account Number:

Service Address:

Please Answer Each Question By Marking The Response Which Applies To The Household At The **Service Address** Listed Above. Please Mark Only One Response Per Question, **Unless Otherwise Indicated.**

Use a soft lead pencil or a blue or black ball-point pen. Make heavy dark marks that fill the circle completely.
Correct Mark ● Incorrect Marks

Your Home

1. WHICH TYPE OF BUILDING BEST DESCRIBES YOUR HOME?
- ○ Mobile Home/Trailer
- ○ Single Family House Unattached
- ○ Two Family House
- ○ Manufactured Home
- ○ Apartment Building with 4 or Fewer Units
- ○ Apartment Building with 5 or More Units
- ○ Townhouse - 3 or More Attached Units
- ○ Other ___________

2. WHICH BEST DESCRIBES THE LOCATION OF YOUR HOME?
- ○ City or Urban
- ○ Suburban
- ○ Town or Village
- ○ Rural Non-Farm
- ○ Farm

3. DO YOU OWN OR RENT YOUR HOME?
- ○ Own
- ○ Rent - Pay for Heating
- ○ Rent - Heat Furnished by Landlord

4. APPROXIMATELY HOW OLD IS YOUR HOME?
- ○ 2 Years or Under
- ○ 3 to 5 Years
- ○ 6 to 10 Years
- ● 11 to 15 Years
- ○ 16 to 20 Years
- ○ 21 to 30 Years
- ○ 31 to 40 Years
- ○ Over 40 Years
- ○ Don't Know

5. DOES YOUR HOME HAVE A BASEMENT AND/OR CRAWL SPACE? (Select One Response from Basement and Crawl Space)

Basement
- ○ No Basement
- ○ Heated Basement
- ○ Unheated Basement

Crawl Space
- ○ No Crawl Space
- ○ Crawl Space

6. WHAT IS YOUR BEST ESTIMATE OF THE SIZE OF YOUR HOME'S LIVING AREA? (Count Basement Only If It is Regularly Heated)
- ○ Under 1200 Sq. Ft.
- ○ 1201 - 2000 Sq. Ft.
- ○ 2001 - 3000 Sq. Ft.
- ○ Over 3000 Sq. Ft.
- ○ Don't Know

Heating and Cooling

7. INDICATE THE TYPE AND APPROXIMATE AGE OF THE HEATING SYSTEM(S) IN YOUR HOME.

(Select As Many As Apply)

Type	0-2	3-5	6-10	11-15	Over 16
○ Electric Heat Pump or Add-On Heat Pump	○	○	○	○	○
○ Electric Furnace	○	○	○	○	○
○ Natural Gas Furnace	○	○	○	○	○
○ Propane/LP Furnace	○	○	○	○	○
○ Oil Furnace	○	○	○	○	○

- ○ Wood or Coal Furnace
- ○ Individual Room Electric Heat (Baseboard, Ceiling Cable, Etc.)
- ○ Other Heating System ___________________
- ○ Don't Know

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8. IF YOU HAVE AN ELECTRIC HEAT PUMP, WHAT TYPE IS IT?
- Heat pump used with a Natural Gas Furnace
- Heat pump used with a Propane Furnace
- Heat pump used with an Oil Furnace
- All-Electric Heat Pump
- Geothermal Heat Pump
- Other ______

9. IF YOU HAVE REPLACED YOUR HEATING SYSTEM SINCE YOU'VE BEEN IN THIS HOME, PLEASE INDICATE YOUR PREVIOUS SYSTEM.
- Not Replaced
- Electric Heat Pump
- Electric Furnace
- Natural Gas Furnace
- Propane/LP Furnace
- Oil Furnace
- Wood or Coal Furnace
- Other ______

10. IS NATURAL GAS (Piped in by a Utility) AVAILABLE IN YOUR NEIGHBORHOOD?
- Yes
- No
- Don't Know

11. MARK THE TYPE AND APPROXIMATE AGE OF AIR CONDITIONING SYSTEM(S) IN YOUR HOME.

(Select As Many As Apply)

Type	0-2	3-5	6-10	11-15	Over 16
Electric Heat Pump or Add-On Heat Pump	○	○	○	○	○
Electric Central Air Conditioning (Other than Heat Pump)	○	○	○	○	○

Age (Years)

- Room/Window Air Conditioning
- No Air Conditioning

12. ARE YOU CONSIDERING INSTALLING A CENTRAL AIR CONDITIONING SYSTEM IN YOUR HOME WITHIN THE NEXT THREE YEARS?
- Yes
- No
- Don't Know

13. WHAT TYPE OF WATER HEATER IS USED IN YOUR HOME?
- Electric
- Natural Gas
- Propane
- Other ______
- None
- Don't Know

14. IF ELECTRIC, IS IT A LEASED WATER HEATER (80, 100, 120 GALLON TANK)?
- Yes
- No
- Don't Know

15. WHAT SIZE IS YOUR WATER HEATER?
- Under 30 Gallons
- 30 - 39 Gallons
- 40 - 49 Gallons
- 50 - 64 Gallons
- Over 64 Gallons
- Don't Know

16. HOW OLD IS YOUR WATER HEATER?
- 2 Years or Less
- 3 - 5 Years
- 6 - 10 Years
- 11 - 15 Years
- Over 15 Years
- Don't Know

17. IF YOU HAVE REPLACED YOUR WATER HEATER SINCE YOU'VE BEEN IN THIS HOME, INDICATE YOUR PREVIOU WATER HEATER TYPE.
- Not Replaced
- Electric
- Natural Gas
- Propane
- Other ______

Appliances

18. MARK EACH OF THE FOLLOWING APPLIANCES FOUNC IN YOUR HOME.

(Select As Many As Apply)

- Refrigerator
- Second Refrigerator
- Detached Freezer
- Range (Electric)
- Range (Natural Gas/Propane)
- Microwave Oven
- Dishwasher
- Clothes Washer
- Clothes Dryer (Electric)
- Clothes Dryer (Natural Gas/Propane)
- Video Cassette Recorder (VCR)
- Television
- Computer
- Dehumidifier
- Waterbed Heater
- Sauna/Hot Tub/Whirlpool
- Swimming Pool Pump
- Well-Water Pump
- Outdoor Security Light

19. WHAT TIMES OF DAY DO YOU NORMALLY USE THE FOLLOWING APPLIANCES?

(Select As Many As Apply)

Weekday			
Television	○ Morning	○ Afternoon	○ Evening/Night
Computer	○ Morning	○ Afternoon	○ Evening/Night
Washer/Dryer	○ Morning	○ Afternoon	○ Evening/Night
Dishwasher	○ Morning	○ Afternoon	○ Evening/Night
Weekend			
Television	○ Morning	○ Afternoon	○ Evening/Night
Computer	○ Morning	○ Afternoon	○ Evening/Night
Washer/Dryer	○ Morning	○ Afternoon	○ Evening/Night
Dishwasher	○ Morning	○ Afternoon	○ Evening/Night

20. ON WHICH OF THE FOLLOWING APPLIANCES DO YOU USE SURGE PROTECTORS?

(Select As Many As Apply)

- Television
- Video Cassette Recorder (VCR)
- Stereo System
- Computer

Energy Management and Conservation

21. AT WHAT TEMPERATURE DO YOU NORMALLY SET YOUR THERMOSTAT FOR HEATING YOUR HOME?
- 65 Degrees or Below
- 66 to 68 Degrees
- 69 to 71 Degrees
- 72 to 74 Degrees
- 75 Degrees or Above
- No Thermostat
- Don't Know

22. DO YOU NORMALLY SET BACK YOUR THERMOSTAT MANUALLY, OR WITH A PROGRAMMABLE FEATURE THAT AUTOMATICALLY CHANGES TEMPERATURE SETTINGS?
- Manual
- Programmable
- Do Not Set Back Thermostat
- No Thermostat
- Don't Know

23. INDICATE HOW MUCH YOU NORMALLY SET BACK YOUR THERMOSTAT TO REDUCE HEATING COSTS.
- 1 or 2 Degrees
- 3 or 4 Degrees
- 5 or 6 Degrees
- 7 Degrees or More
- Not at All
- No Thermostat
- Don't Know

24. WHEN USING YOUR AIR CONDITIONING, WHAT TEMPERATURE DO YOU TRY TO MAINTAIN?
- Don't have Air Conditioning
- 68 Degrees or Below
- 69 to 71 Degrees
- 72 to 74 Degrees
- 75 to 77 Degrees
- 78 to 80 Degrees
- 81 Degrees or Above
- Don't Know

Your Family

25. PLEASE MARK THE APPROPRIATE NUMBER OF PEOPLE FOR EACH AGE CATEGORY LIVING IN YOUR HOME?

Age	One	Two	Three	Four	Five	Six or More
Under 18 Years	○	○	○	○	○	○
18 - 24 Years	○	○	○	○	○	○
25 - 34 Years	○	○	○	○	○	○
35 - 44 Years	○	○	○	○	○	○
45 - 54	○	○	○	○	○	○
55 - 64	○	○	○	○	○	○
Years & Over	○	○	○	○	○	○

26. HOW MANY FULL TIME WAGE EARNERS ARE IN YOUR HOME? INCLUDE ANYONE WORKING AT LEAST 24 HOURS PER WEEK.
- One
- Two
- Three or More
- None (Retired, Disabled, Etc.)

27. WHAT IS THE HIGHEST LEVEL OF EDUCATION COMPLETED BY THE HEAD OF THE HOUSEHOLD?
- Grade School or Less
- Some High School
- Completed High School
- Some College or Technical School
- Completed College

28. WHAT CATEGORY BEST DESCRIBES YOUR TOTAL ANNUAL HOUSEHOLD INCOME FROM ALL SOURCES?
- Under $15,000
- $15,001 - $30,000
- $30,001 - $40,000
- $40,001 - $50,000
- $50,001 - $60,000
- $60,001 - $70,000
- $70,001 - $80,000
- Over $80,000

It is expected that the future consumption of electricity will be affected by home computer, entertainment, security, and communication systems. Your answers to the following questions will help us meet those future energy requirements.

Home Computer

IF YOU DON'T HAVE A HOME COMPUTER GO TO QUESTION #32.

29. WHAT IS THE PRIMARY USE FOR YOUR HOME COMPUTER?
- Business
- Personal
- Don't Have

30. WHAT IS THE PRIMARY USE FOR YOUR ONLINE/INTERNET SERVICE?
- Business
- Personal
- Don't Have

31. OF THE FOLLOWING LIST, WHAT COMPONENTS DO YOU HAVE AS PART OF YOUR COMPUTER SYSTEM?

(Select As Many As Apply)

- Data Only Modem
- FAX/Data Modem
- FAX/Data/Voice Modem
- Sound Board
- CD-ROM Drive

Home Entertainment

32. CHECK EACH OF THE HOME ENTERTAINMENT SERVICES YOU CURRENTLY OWN OR SUBSCRIBE TO.

(Select As Many As Apply)

- Cable TV Service
- Premium Cable Service (HBO, Showtime, Cinemax, etc.)
- Digital Satellite System (DDS)
- Satellite Dish
- None of the Above

Home Communication

33. HOW LONG HAVE YOU BEEN WITH YOUR CURRENT LONG DISTANCE TELEPHONE CARRIER?
- Less Than 3 Months
- 3 to 6 Months
- 6 Months to 1 Year
- More Than 1 Year
- Don't Know

34. TO WHICH OF THE FOLLOWING SERVICES DO YOU CURRENTLY SUBSCRIBE WITH YOUR LOCAL PHONE SERVICE PROVIDER?

(Select As Many As Apply)

- Voice Mail
- Call Waiting
- Call Forwarding
- Caller ID
- None of the Above

35. WHAT TYPE OF CELLULAR PHONE DO YOU CURRENTLY USE?
- Handheld/Portable
- Car
- Other ______________________
- None

36. WHAT IS THE PRIMARY USE FOR YOUR CELLULAR PHONE?
- Business
- Personal
- None

37. WHAT IS THE PRIMARY USE FOR YOUR PAGER?
- Business
- Personal
- None

38. WHAT FEATURES DOES YOUR PAGER HAVE?

(Select As Many As Apply)

- Date and Time Display
- One-Way Communication
- Two-Way Communication
- Multiple Message Slots
- Auto Send
- Other ______________________

Home Security

39. WHICH OF THE FOLLOWING BEST DESCRIBES THE TYPE OF HOME SECURITY SYSTEM YOU CURRENTLY HAVE?
- Monitored System (You pay a monthly monitoring fee)
- Non-Monitored System (No monthly monitoring fee is paic
- Other/None

THANKS - WE APPRECIATE YOUR HELP.

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Request No. 20:

Refer to page 3-7 of the DSM section of the report. If no specific dollar amounts were assigned to reductions to CO_2 and NOx emissions, explain how those reductions were included in the evaluation of DSM programs.

Response:

The reductions in CO_2 and NOx emissions were estimated in the evaluation to quantify the additional environmental benefits that can result from the implementation of DSM programs. Since there are no market values for CO_2 and NOx emissions that would allow for estimating their economic value, as indicated on page 3-7 (fourth paragraph) of the report, these additional environmental benefits are expressed only in tons of reduced emissions. Therefore, the economic benefits of these reductions could not be considered in the cost-benefit analysis of the DSM programs.

Respondent: N. Tibberts

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Request No. 21:

Refer to page 3-8 of the DSM section of the report. Provide the level of participation by KPC's customers in the Load Management Water Heating Program to date and identify any load impacts that can be directly attributed to the program.

Response:

As of November 30, 1999, a total of 91 KPCo customers were participating in the Load Management Water Heating Program. Estimated total DSM-related load impacts of the program include (1) a reduction in summer and winter peak demands, coincident with the AEP System internal peak, of 19 kW and 67 kW, respectively, (2) an annual energy shift from on-peak to off-peak of 106 MWh, and (3) an annual energy savings of 13 MWh.

Respondent: N. Tibberts

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Request No. 22:

Refer to page 3-9 of the DSM section of the report. Explain how and why the measure-screening and program-screening processes were combined in the 1999 DSM screening rather than being performed separately as has been done in prior screenings.

Response:

The AEP measure-screening and program-screening processes were combined by simply performing the cost-benefit analysis on a program basis, i.e. analyzing each program's DSM measures together, rather than analyzing the DSM measures individually. This combination streamlined the AEP screening process by eliminating an interim step that is no longer needed, since the DSM measures had been previously identified for program implementation.

Respondent: N. Tibberts

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Request No. 23:

Refer to page 3-10 of the DSM section of the report, specifically Paragraph H.2. Provide a more thorough description and explanation of how increasing competition may affect DSM in the future and why the emphasis in future evaluations would be more from a ratepayer perspective than from a societal perspective.

Response:

Increasing competition can reduce potential DSM levels because the cost-effectiveness of the programs would be analyzed from a short-term perspective, rather than a long-term perspective. As explained on page 3-1 (second paragraph) of the report, the concept of cost-effectiveness of DSM programs has shifted from a regulation-based long-term perspective to the more appropriate market-based short-term perspective because of increasing competition in the electric utility industry. As a result of analyzing the DSM programs on a short-term perspective, the long-term benefits from future capacity deferral will be significantly decreased, if not eliminated, thereby reducing the opportunity for DSM programs to become cost-effective, and thus reducing future potential DSM levels.

Page 3-5 (last paragraph) of the report refers to the shifting of the emphasis of the DSM evaluation process from a societal perspective to a ratepayer perspective due to the anticipation of deregulation. The emphasis in future DSM evaluations will be based on a ratepayer perspective in order to determine the associated potential revenue loss, which can affect future customer rates and, thus, the Company's ability to remain competitive in a deregulated environment. Program evaluations based on a societal perspective do not take into consideration any revenue loss that may occur. By incorporating the effect of revenue loss in the DSM evaluation, the opportunity is reduced for DSM programs to become cost-effective, which can reduce future potential DSM levels.

Respondent: N. Tibberts

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Request No. 24:

Refer to page 4-6 of the Resource Forecast section of the report. Provide an explanation for the determination by AEP that a satisfactory level of capacity-deficient days is between 5 and 10% of the number of days in a year.

Response:

The determination of a reliability criterion that is considered reasonable and appropriate for planning purposes is essentially based on judgment, taking into account both historical and anticipated circumstances. As stated in the last paragraph on page 4-6 of the report, AEP's "target reliability and installed reserve levels ... reflect nominal forecasted load and capacity conditions, and assume that sufficient reserves would be available on neighboring power systems to cover the resulting capacity deficiencies expected to occur. ... As reserve margins on the neighboring systems change, or as the availability performance of AEP's generating units changes, the reliability level judged to be adequate on the AEP System may need to be changed accordingly."

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Request No. 25:

Refer to page 4-6 of the Resource Forecast section of the report. Provide support for the projection that AEP's average on-peak equivalent availability will be 80% or better during the forecast period. Provide the comparable equivalent availability data for the AEP System for the 10-year period from 1989 through 1998.

Response:

See the accompanying Attachment 1, which provides actual (1989-1999) and projected (2000-2013) average on-peak equivalent availability (EA) factors for steam generating units on the AEP System (including Buckeye Power). The EA factors are shown on two bases: (1) AEP-operated fossil steam capacity (i.e., including all of Conesville 4 and excluding Beckjord, Stuart, Zimmer and Cook Nuclear), and (2) total steam capacity.

As the attachment indicates, AEP's fossil units have operated at above 80% EA since 1996. However, the extended outage of the Cook Nuclear Plant has had a significant impact on the total steam EA. The projection assumes that Cook will return to service in 2000.

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Item No. 25
Attachment 1
Page 1 of 1

AMERICAN ELECTRIC POWER
(Including Buckeye Power)
On-Peak Average Annual Equivalent Availability Factors for Steam Generating Units

	Actual 1989 - 1999										
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Jan - Nov 1999
AEP-Operated Fossil Steam	79.7	79.8	75.2	78.2	75.7	77.1	79.0	84.0	85.5	83.6	82.2
Total Steam	78.6	78.2	76.5	74.7	77.3	75.1	79.0	84.7	82.7	76.7	74.8

	Projected 2000 - 2013									
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009 thru 2013
AEP-Operated Fossil Steam	87.5	86.2	86.5	87.3	87.4	87.4	87.9	87.4	88.1	87.5
Total Steam	86.0	85.8	85.6	86.0	86.4	86.8	86.3	86.5	87.1	86.5

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Request No. 26:

Refer to page 4-7 of the Resource Forecast section of the report. Provide a detailed explanation for the assumption that the unit power agreement between KPC and AEP Generating Company will expire at the end of 2004. Identify the factors that might lead to the contract being extended beyond 2004.

Response:

As discussed in the response to Request No. 3 of this set of requests, the unit power agreement that governs Kentucky Power's 390-MW capacity purchase from the Rockport Plant, taking into account the provision that has allowed for a 5-year extension of that contract, expires at year-end 2004. There is no provision for extending the contract beyond 2004.

Respondent: N. Tibberts

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Request No. 27:

Refer to page 4-11 of the Resource Forecast section of the report, specifically the section dealing with non-utility generation. To what extent is KPC familiar with plans by Dynegy Corp. to construct a merchant plant near the site of its Big Sandy Generating Station? What consideration has been given to the potential construction of that plant?

Response:

The American Electric Power Service Corporation (AEPSC), as agent of KPCo, has received a formal request from Dynegy to conduct an impact study to integrate Dynegy's proposed power plant into the AEP System near the Big Sandy Generating Plant. AEPSC is conducting the studies based on the principles prescribed by FERC Orders 888 and 889. Studies are underway to determine the feasibility of integrating the new generation at that location. As part of the study, the specific facilities required to integrate the new power plant and to address any transmission problems created by the new generation will be identified.

Respondent: N. Tibberts

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Request No. 28:

Refer to page 4-15 of the Resource Forecast section of the report, specifically the statement that indicates that most of AEP's total coal requirements are obtained under long-term arrangements. Explain or define what is meant by 'most' and provide the split between contract and spot market purchases for the AEP System for each of the years from 1994 through 1998.

Response:

AEP's general objective with respect to coal procurement is to obtain approximately 15-20% of the operating companies' and associated companies' total annual coal requirements under spot coal purchase arrangements. The following table shows the split between contract and spot market purchases for the AEP System for each of the years 1994 through 1998.

YEAR	SPOT MILLION TONS	SPOT % SHARE	CONTRACT MILLION TONS	CONTRACT % SHARE
1994	9.8	20%	39.2	80%
1995	5.0	11%	41.7	89%
1996	6.4	13%	42.5	87%
1997	6.8	14%	43.3	86%
1998	9.9	19%	43.1	81%

Respondent: N. Tibberts

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Request No. 29:

Refer to pages 4-15 and 4-16 of the Resource Forecast section of the report. Identify which of the AEP units have been modified in order to be dual-fuel capable as part of AEP's compliance plan.

Response:

The AEP generating units that have been modified for dual-fuel capability are Conesville Units 1-3.

Respondent: N. Tibberts

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Request No. 30:

Refer to Exhibit 4-10 of the report. The Big Sandy station has the lowest average production costs of all AEP generating capacity. Given the central dispatching of the AEP System, identify how much of KPC's load and energy requirements are served from KPC's own big Sandy generating station.

Response:

The requested information is not available. However, based on after-the-fact simulation/reconstruction of the operation of the AEP System, whenever Big Sandy Unit No. 2 is operating, KPCo's jurisdictional customers are the first to benefit, for ratemaking purposes, by Big Sandy's low-cost output.

Respondent: N. Tibberts

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Request No. 31:

Refer to page 4-10 of the report and KPC's firm purchases of energy from the Rockport plant as shown in Exhibit 4-23. Identify where the Big Sandy and the Rockport station fall in the order of dispatch for the AEP System. Identify how much energy KPC is required to purchase under the unit power agreement on an annual basis. Explain how the determination is made as to what energy will be sold off-system and what energy will go toward serving KPC's native load customers.

Response:

The Rockport and Big Sandy plants have among the lowest operating (variable) costs of the generating plants on the AEP System; thus, they are among the first to be incrementally loaded as the demand requirements on the AEP System rise.

Under the unit power agreement, KPCo is required to purchase 15% of each Rockport unit's hourly output. For example, when each unit is fully loaded at 1,300 MW, KPCo's purchase amounts to 195 MW from each unit, or 390 MW from both units.

KPCo's generation resources are jointly dispatched with those of the other operating companies of the AEP System to meet the combined load requirements of the total AEP System. Such requirements include the operating companies' native/internal loads, as well as certain off-system sales in which the operating companies participate through their member-load-ratio (MLR) shares, as prescribed in the AEP System Interconnection Agreement. The determination of the portion of the AEP System's generation that is sold off-system and the portion that is used to serve the native load customers of the operating companies (including KPCo) is made on an after-the-fact basis; a simulation/reconstruction of the dispatch is conducted, whereby the higher-cost resources are allocated to off-system sales, on an incremental basis. The operating companies, including KPCo, are compensated for the incremental costs of their resources that were allocated to such off-system sales and, in addition, share the net revenues from these sales on an MLR basis.

Respondent: N. Tibberts

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Request No. 32:

Refer to Exhibit 4-11 of the report. Explain the basis for the different life expectancies (50 years, 60 years, and 70 years) shown for the different generating units identified in the exhibit.

Response:

The generating units that are listed on Exhibit 4-11 of the report as having a 50-year life expectancy have "wet-bottom" boilers, and the units listed as having a 60-year life expectancy have "dry-bottom" boilers. Historically, wet-bottom units have experienced greater deterioration than dry-bottom units. Accordingly, for planning purposes, a shorter life was generally assumed for the wet-bottom units.

The only unit shown on Exhibit 4-11 to have a 70-year life is Glen Lyn 5. Based on an assessment of the operating performance of this unit, the retirement date was assumed to be 2014.

Respondent: N. Tibberts

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Request No. 33:

Refer to Exhibit 4-25 of the report, which compares the AEP System's 1996 and 1999 expansion plans. Identify the factors that have contributed to the decrease in the amount of capacity expected to be added through 2016.

Response:

For the 1999 expansion plan, Exhibit 4-25 shows an aggregate of 7,700 MW of undesignated blocks of resource additions through 2016. This is 1,655 MW less than the 9,355 MW of capacity additions shown for the 1996 expansion plan, which consists of a mixture of combustion turbine (CT) units, combined cycle (CC) units and coal-fired units.

In the above comparison, it is important to note that the 7,700 MW of undesignated block additions in the 1999 plan applies to both the summer and winter seasons, i.e., no summer deratings are involved. However, the 9,355 MW of capacity additions in the 1996 plan reflects winter ratings, rather than summer ratings, which total 8,065 MW. Thus, these capacity additions have a total summer derating of 1,290 MW.

Since such capacity additions were determined on the basis of meeting the AEP System's projected summer (annual) peak demand, summer ratings provide a more meaningful comparison between the 1996 and 1999 plans. On this basis, total resource additions through 2016 in the 1999 plan becomes 365 MW less (rather than 1,655 MW less) than in the 1996 plan.

The 365-MW difference would then be attributable to the lower summer peak demand projected for the year 2016 under the 1999 plan than was projected under the 1996 plan.

Respondent: N. Tibberts

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Request No. 34:

Refer to page 2 of the Appendix regarding Short-term Energy Models. Explain why there are only two exogenous variables for cooling degree-days and three exogenous variables for heating degree-days.

Response:

Various forms of weather response were tested against the data, and the form that resulted in the best fit, while producing a roughly U-shaped weather response function, was selected.

Respondent: N. Tibberts

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Request No. 35:

Refer to page 62 of the Appendix showing residential customers, actual and forecast. For the period 1989 through 1998 the growth in the number of customers has averaged approximately 1.05%. Identify the factors that led to the forecast growth of only .8 to .9% and explain how these factors were used to produce the forecast growth rate.

Response:

The growth rates in question are simply derived from the forecast number of residential customers. The factors producing this forecast are the historical data input to the forecast model, the forecasts of the input variables, and the estimated coefficients of the model. All this information is given on pages 56-61 of the Appendix.

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Request No. 36:

Page 74 of the Appendix shows exogenous variables for the commercial sector. Given the similarities that residential and commercial customers have regarding temperature-sensitive load, explain why there are no temperature-sensitive variables for the commercial sector.

Response:

The commercial model does include cooling degree-days as an exogenous variable, which would reflect weather sensitivity.

Respondent: N. Tibberts

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Request No. 37:

Refer to pages 90 and 91 of the Appendix that show the exogenous variables for the Mine Power sector. Service area coal production has remained almost flat over the period from 1989 through 1998. Identify the factors that support the forecasted increase in service area production and explain how those factors were used to derive the forecasted increase. Also, explain how the forecasted increase in service area mine production comports with the statement on page 2-14 of the report that references the continued shift of production from eastern to western states.

Response:

The coal produced in the KPCo service area tends to be lower in sulfur content than coal produced in some other parts of the eastern U.S., for example, Ohio or northern West Virginia. As a result, service-area coal remains somewhat competitive with western coal and low sulfur eastern coal and is thus expected to see some slow growth in production during the forecast period. The service-area coal production forecast relies on the national forecast for coal production and coal consumption by electric utilities as developed by EIA/DOE. The forecast for the KPCo service area is for regional coal-production growth to be slower than the national rate.

Respondent: N. Tibberts