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VIA HAND DELIVERY

July 1, 2011

RECEIVED

JUL 01 2011

PUBLIC SERVICE
COMMISSION

Jeff Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602-0615

Re: Duke Energy Kentucky 2011 Integrated Resource Plan

Dear Mr. Derouen:

Enclosed please find an original and ten copies of the Public Version of Duke Energy Kentucky's 2011 Integrated Resource Plan.

Also enclosed are an original and twelve copies of the Petition for Confidential Treatment of Information Contained in its Integrated Resource Plan and one copy of the Confidential Version of Duke Energy Kentucky's 2011 Integrated Resource Plan.

Please date-stamp the extra cover sheet copies of the Public Version and the extra two copies of the Petition and return to me in the enclosed envelope.

Sincerely,

Kristen Cocanougher

Kristen Cocanougher

cc: Dennis Howard (w/enclosures)
Florence Tandy (w/enclosures)
Carl Melcher (w/enclosures)

421871

Duke Energy®

JULIE S. JANSON
President

Duke Energy Ohio, Inc.
Duke Energy Kentucky, Inc.
139 E. Fourth Street
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July 1, 2011

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

RE: Duke Energy Kentucky 2011 Integrated Resource Plan

Dear Mr. Derouen:

Pursuant to 807 KAR 5:058, Duke Energy Kentucky submits ten (10) bound and one (1) unbound copies of the Duke Energy Kentucky 2011 Integrated Resource Plan (IRP) to the Public Service Commission of Kentucky. Please note that the 11 copies have been redacted to protect the confidentiality of certain information. Concurrently with the filing of this Duke Energy Kentucky 2011 IRP, the Company has filed a petition with the Commission requesting confidential treatment of such information.

The Duke Energy Kentucky IRP contains chapters generally covering the following areas: Objectives and Process; Load Forecast; Demand-Side Management; Supply-Side Resources; Environmental Compliance Planning; Electric Transmission Forecast; and Selection and Implementation of the Plan. In addition, an Executive Summary, which provides a synopsis of the entire report, has been included. For your convenience, "Attachment G" is a Kentucky Index which lists the Chapter(s) and Section(s) of the report that are responsive to each of the Kentucky regulations.

Please note that Rocco D'Ascenzo, Legal Department, 139 East Fourth Street, 13th Floor, Cincinnati, OH 45202, (513) 287-4320, is the Attorney of Record for this forecast.

Specific questions regarding the contents of this report should be directed to Robert McMurry, Integrated Resource Planning, at the corporate offices of Duke Energy located at 526 South Church Street, Charlotte, NC 28202.

Yours truly,

Julia S. Janson

421547

Duke Energy Kentucky

2011 INTEGRATED RESOURCE PLAN

CERTIFICATE OF SERVICE

The undersigned states that she is the President of Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.; that she is duly authorized in such capacity to execute and file this Integrated Resource Plan on behalf of Duke Energy Kentucky, Inc.

A copy of the attached "Notice of Filing" has been made by depositing the same in the United States mail, First Class postage prepaid to the following intervenors in Duke Energy Kentucky's last integrated resource plan review proceeding:

Honorable Dennis G. Howard, II
Assistant Attorney General
1024 Capital Center Drive, Suite 200
Frankfort, Kentucky 40601

Florence W. Tandy
Northern Kentucky Community Action Commission
P.O. Box 193
Covington, Kentucky 41012

Carl Melcher
Northern Kentucky Legal Aid, Inc.
302 Greenup
Covington, Kentucky 41011

One copy of this Report will be kept at the principal business office of Duke Energy Kentucky, Inc., for public inspection during office hours. A copy of the Report will be provided to any person, upon request, at cost, to cover expenses incurred.

Julia S. Janson
President, Duke Energy Ohio and Kentucky

7-1-2011
Date

NOTICE OF FILING

Please take notice, that pursuant to 807 KAR 5:058, Section 2, Part (2), Duke Energy Kentucky, Inc., has, this 1st day of July 2011, filed a copy of the Duke Energy Kentucky 2011 Integrated Resource Plan (IRP) with the Public Service Commission of Kentucky.

This IRP contains Duke Energy Kentucky, Inc.'s assessment of various demand-side and supply-side resources to cost effectively meet jurisdictional customer electricity service needs.

A copy of the IRP, as filed, will be available for review at the offices of Duke Energy Kentucky, Inc. during normal business hours. A copy of this IRP will be provided, at cost, to cover expenses incurred, upon request.

RECEIVED
JUL 01 2011
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of Duke Energy Kentucky, Inc.'s Integrated Resource Plan	)))	Case No. 2011-______

PETITION OF DUKE ENERGY KENTUCKY, INC.
FOR CONFIDENTIAL TREATMENT OF INFORMATION
CONTAINED IN ITS INTEGRATED RESOURCE PLAN

Duke Energy Kentucky, Inc. ("Duke Energy Kentucky" or "Company"), pursuant to 807 KAR 5:001, Section 7, respectfully requests the Commission to classify and protect certain information that is contained in Duke Energy Kentucky's 2011 Integrated Resource Plan ("IRP") contemporaneously filed with this Petition. The information that Duke Energy Kentucky seeks confidential treatment generally includes: (1) information related to operations and management ("O&M") costs, projected fuel and environmental compliance costs, power market prices, emission allowance cost, energy efficiency program and avoided cost, projected capacity, and resource alternative capital costs; (2) information regarding projected sales and revenue requirements; (3) supply side screening curves and resource evaluations; and (4) critical transmission system maps.

The public disclosure of the information described would place Duke Energy Kentucky at a commercial disadvantage as it negotiates contracts with various suppliers and vendors and potentially harm Duke Energy Kentucky's competitive position in the marketplace, to the detriment of Duke Energy Kentucky and its customers. Moreover, Duke Energy Kentucky's transmission system maps show the location of critical infrastructure necessary to deliver safe and reliable electric service to its consumers. The public release of this information would create a security risk for both the Company and its customers.

In support of this Petition, Duke Energy Kentucky states:

1. The Kentucky Open Records Act exempts from disclosure certain commercial information. KRS 61.878 (1)(c). To qualify for this exemption and, therefore, maintain the confidentiality of the information, a party must establish that disclosure of the commercial information would permit an unfair advantage to competitors of that party. Public disclosure of the information identified herein would, in fact, prompt such a result for the reasons set forth below.

2. The information regarding power production costs that Duke Energy Kentucky wishes to protect from public disclosure -- including supply side screening curves, projected costs of fuel and O&M expenses, capital costs, power market prices, projected capacity and present value revenue requirements ("PVRR") -- is identified in the filing submitted concurrently herewith. This information was developed internally by Duke Energy Kentucky personnel, is not on file with any public agency, and is not available from any commercial or other source outside Duke Energy Kentucky. The aforementioned information is distributed within Duke Energy Kentucky only to those employees who must have access for business reasons. If publicly disclosed, this information setting forth Duke Energy Kentucky's costs of operation, expected need for fuel and allowances and projected capacity could give competitors an advantage in bidding for and securing new resources. Similarly, disclosure would afford an undue advantage to Duke Energy Kentucky's vendors and suppliers as they would enjoy an obvious advantage in any contractual negotiations to the extent they could calculate Duke Energy Kentucky's requirements and what Duke Energy Kentucky

anticipates those requirements to cost. Finally, public disclosure of this information, particularly as it relates to supply-side alternatives, would reveal the business model Duke Energy Kentucky uses -- the procedure it follows and the factors and inputs it considers -- in evaluating the economic viability of various generation related projects. Public disclosure would give Duke Energy Kentucky's contractors, vendors and competitors access to Duke Energy Kentucky's cost and operational parameters, as well as insight into its contracting practices. Such access would impair Duke Energy Kentucky's ability to negotiate with prospective contractors and vendors, and could harm the Duke Energy Kentucky's competitive position in the power market, ultimately affecting the costs to serve customers.

3. Duke Energy Kentucky requests confidential protections for certain third-party data contained in the IRP. In developing the 2011 IRP, Duke Energy Kentucky used certain confidential and proprietary data modeling consisting of confidential information belonging to third parties who take reasonable steps to protect their confidential information, such as only releasing such information subject to confidentiality agreements. Duke Energy Kentucky used forecasts of various commodities and inputs such as SO_2 emission allowances prices, NO_x emission allowance prices, mercury emission allowance prices, power market prices, coal prices, gas prices, and oil prices developed by an independent third party, Ventyx Energy, LLC, subject to confidentiality restrictions. Duke Energy Kentucky is contractually bound to maintain such information confidential. Moreover, this information is deserving of protection to protect Duke Energy Kentucky's customers. If allowance brokers or equipment vendors knew Duke Energy Kentucky's forecasted emissions and fuel prices, by station or otherwise, such brokers or vendors would have an unfair advantage in negotiating future emission allowance or emission control equipment sales, to the detriment of Duke Energy

Kentucky and its customers. Furthermore, if competitors of Duke Energy Kentucky knew such forecasts, they could have an advantage in competing for new business against Duke Energy Kentucky.

4. Duke Energy Kentucky requests confidential treatment for the transmission system maps included in the IRP. These maps show the location of Critical Energy Infrastructure Information ("CEII"), which has been granted confidential treatment in the past. Duke Energy Kentucky takes all reasonable steps in order to protect the CEII, including, but not limited to, only sharing such information internally on a need to know basis. The reliability entities with access to such data, such as Midwest Independent System Operator ("MISO") also take appropriate precautions to protect such data. This information needs to be kept confidential in order to continue to provide delivery of safe and reliable electric service to Duke Energy Kentucky customers. The release of this information would provide a security risk for the Company and its customers.

5. The information for which Duke Energy Kentucky is seeking confidential treatment is not known outside of Duke Energy Kentucky.

6. The information for which Duke Energy Kentucky is seeking confidential treatment is similar in nature to that contained in the Company's 2008 IRP and which the Commission granted protection on or about January 8, 2009.

7. The information that Duke Energy Kentucky seeks confidential treatment herein demonstrates on its face that it merits confidential protection. If the Commission disagrees, however, it must hold an evidentiary hearing to protect the due process rights of the Company and supply the Commission with a complete record to enable it to reach a

decision with regard to this matter. *Utility Regulatory Commission v. Kentucky Water Service Company. Inc.,* Ky. App., 642 S.W.2d 591, 592-94 (1982).

8. Duke Energy Kentucky does not object to limited disclosure of the confidential information described herein, pursuant to an acceptable protective agreement, to the Attorney General or other intervenors with a legitimate interest in reviewing the same for the purpose of commenting on Duke Energy Kentucky's 2011 IRP.

9. In accordance with the provisions of 807 KAR 5:001 Section 7, the Company is filing with the Commission one copy of the 2011 IRP under seal and ten (10) copies without the confidential information.

WHEREFORE, Duke Energy Kentucky, Inc. respectfully requests that the Commission classify and protect as confidential the specific information described herein.

Respectfully submitted,

DUKE ENERGY KENTUCKY, INC.

Rocco O. D'Ascenzo (92796)
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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of Duke Energy Kentucky, Inc.'s Petition for Confidential Treatment of Information Contained in Duke Energy Kentucky, Inc.'s 2011 Integrated Resource Plan was served on the following by overnight mail, this 1st day of July 2011.

Rocco O. D'Ascenzo

Honorable Dennis G. Howard, II
Assistant Attorney General
1024 Capital Center Drive, Suite 200
Frankfort, Kentucky 40601

Florence W. Tandy
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Duke Energy®

Kentucky

The Duke Energy Kentucky 2011 Integrated Resource Plan

Public Version

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PUBLIC SERVICE COMMISSION

July 1, 2011

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1. EXECUTIVE SUMMARY

A. OVERVIEW

Duke Energy Kentucky, Inc. (Duke Energy Kentucky, or Company) is a wholly owned subsidiary of Duke Energy Ohio, Inc. (Duke Energy Ohio) that provides electric and gas service in the Northern Kentucky area contiguous to the Southwestern Ohio area served by Duke Energy Ohio. Duke Energy Kentucky provides electric service to approximately 136,000 customers in its approximate 300 square mile service territory. Duke Energy Kentucky's service territory includes the cities of Covington and Newport, Kentucky. The Company has both a legal obligation and a corporate commitment to meet the energy needs of its customers in a way that is adequate, efficient, and reasonable. Planning and analysis helps the Company achieve this commitment to customers. Duke Energy Kentucky utilizes a resource planning process to identify the best options by which to serve customers' energy and capacity needs in the future. The process incorporates both quantitative analysis and qualitative considerations. For example, quantitative analysis provides insights on future risks and uncertainties associated with the load forecast, fuel and energy costs, and renewables. Qualitative perspectives, such as the importance of fuel diversity, the Company's environmental profile and the stage of technology deployment are also important factors to consider as long-term decisions are made regarding new resources. The end result is a resource plan that serves as an important tool to guide the Company in making business decisions to meet customers' near-term and long-term energy needs.

The overall objective of the resource planning process is to develop a robust and reliable economic strategy for meeting the needs of customers in a very dynamic and uncertain environment. Uncertainty always plays a role in the planning process and can normally be expected to be a concern when dealing with factors such as emerging environmental regulations, load growth or decline, and the pricing of fuel and market products.

Major changes in the Company's 2011 Resource Plan from the 2008 Resource Plan are outlined below:

- EXPECTED RETIREMENT OF MIAMI FORT 6 -

The primary driver for the January 1, 2015 retirement date of Miami Fort 6 is the recently proposed United States Environmental Protection Agency (EPA) Utility Maximum

Achievable Control Technology (MACT) rule. The rule is expected to be finalized in November 2011, with an initial compliance date on or near January 1, 2015. Additional drivers to the unit's expected retirement include, multiple emerging environmental regulations including the Transport Rule, new water quality standards, fish impingement and entrainment standards, Coal Combustion Residuals (CCR) rule and the new Sulfur Dioxide (SO_2), Particulate Matter (PM) and Ozone National Ambient Air Quality Standards. The retirement of Miami Fort 6 results in a capacity need in the 2015 timeframe and thus, places the emphasis of this resource plan on how to best meet this need.

- LOWER NATURAL GAS PRICE FORECAST -

The fundamental price forecast for natural gas has decreased primarily due to newly-discovered domestic supplies of the fuel located in shale deposits. The potential of this new supply has lowered the projected fundamental natural gas price for the foreseeable future.

- UNCERTAINTY IN A CARBON CONSTRAINED FUTURE –

In 2007 through 2009, there were multiple greenhouse gas (GHG) cap and trade legislative proposals put forth in Congress, with one bill, The American Clean Energy and Security Act of 2009 (H.R. 2454), passing the House of Representatives in June, 2009. There is currently no momentum in Congress to consider GHG legislation at least through 2012. Beyond 2012, the prospects for possible enactment of any legislation mandating reductions in GHG emissions are highly uncertain. While the Company continues to believe that Congress will eventually adopt some form of mandatory GHG emission reduction legislation, the timing and form of any such legislation remains highly uncertain.

- RECESSIONARY IMPACTS ON THE PROJECTED LOAD FORECAST-

Between 2007 and 2009 the actual peak load dropped 113 MWs and the peak energy dropped 519 GW-hrs due to the recessionary impacts on the economy. The long-term peak and energy growth rate in the 2011 forecast is slightly higher than the 2008 forecast, but we are only now reaching the pre-recessionary levels of 2007.

- TRANSITION TO PJM REGIONAL TRANSMISSION ORGANIZATION (PJM) - Duke Energy Kentucky will operate within PJM consistent with its intention to transfer the Duke Energy Kentucky transmission assets from the Midwest System Operator (MISO) to the PJM regional transmission organization effective January 1, 2012.

An overview of the resource plan is presented on the remaining pages of the Executive Summary. Further details regarding the planning process, issues, uncertainties, and alternative plans are presented and discussed in the following sections to comply with Commission's Rule 807 KAR 5:058. For further guidance on the location of information required pursuant to compliance with 807 KAR 5:058, please refer to the cross-reference table in Appendix G.

B. PLANNING PROCESS RESULTS

Given the numerous uncertainties described above, the Company believes the most prudent approach is to create a plan that is robust under various possible future scenarios. At the same time, the Company must maintain its flexibility to adjust to evolving regulatory, economic, environmental, and operating circumstances.

Duke Energy Kentucky increase in resource requirement in 2015 is driven primarily by the anticipated retirement of Miami Fort Unit 6. Miami Fort 6 summer Maximum Net Dependable Capacity (MNDC) is 163 MWs and represents approximately 15% of the Duke Energy Kentucky generation resources. The base planning assumptions included in the 2011 resource plan include:

- Demand Side Management – Under the current Demand Side Management (DSM) Program and prior Commission Orders, all of the programs will end December 2012, unless an application is made to continue them. It is the Company's intention to submit a filing subsequent to this report, requesting the approval of a set of energy efficiency (EE) and demand response products and services. The 2011 IRP analysis includes the level of energy efficiency and demand response products and services that the Company anticipates will be included in its DSM Rider application filing.
- Renewable Energy – There is not currently a Kentucky or federal renewable energy portfolio standard. However, to assess the impact to the long-term resource need, the Company believes it is prudent to plan for a renewable energy portfolio standard. In

this resource plan, an assumption was made that 5% of retail sales would be met with renewable energy sources, increasing 0.5% per year starting in 2016 through 2025.

- Carbon Constrained Future – One regulatory construct was evaluated to assess the impact of potential climate change legislation. This consisted of a carbon dioxide (CO_2) cap-and-trade construct beginning in 2016. The associated allowance prices were assumed to be near the lower end of estimated allowance pricing of previously proposed legislation, such as H.R. 2454.
- Clean Energy Future - The Company also evaluated the impacts of a potential Federal Clean Energy Standard, where an increasing percentage of retail sales, starting in 2016, would be required to come from energy efficiency, various types of renewable energy sources, coal generation with carbon capture and sequestration, new nuclear generation, and new combined cycle natural gas generation.
- Reserve Margin – Using 2010 tested values of unforced capacity (UCAP) as set forth by PJM, the reserve margin based on the installed capacity and the application of the percentage that PJM is coincident with the Duke Energy Kentucky peak, the Reserve Margin used for the 2011 resource plan is 14.5%.

In the short term, the analysis concentrated on determining the best replacement generation option for Miami Fort 6 in 2015 and to identify the amount, type and timing for the longer-term generation needs through 2031. An overview of the recommended resource plan resulting from the planning process is outlined below and summarized on Table A.1.

Short Term: To meet the capacity and energy need created by the retirement of Miami Fort 6, the recommended replacement option is the installation or purchase of 140 MW of combined cycle generation (CC) capacity in 2015. Though CC generation was selected as the optimal replacement, new coal generation was competitive as a replacement option. Duke Energy Kentucky is evaluating options to satisfy the 2015 capacity need. In addition to pursuing additional generating capacity, the Company anticipates seeking approval of additional energy efficiency and demand response programs. These programs are anticipated to result in a 47 MW reduction in peak demand by 2015.

Long Term: Assuming successful implementation of additional energy efficiency and demand response programs and of the anticipated renewable energy requirements, the first additional capacity need is for 35 MWs of CC capacity in 2027. If the anticipated renewable energy requirements do not develop, this would accelerate the need for new generation to 2022. The long-term needs are similar under the Clean Energy Standard regulatory construct, with the exception that the optimal resource would be 35 MW of nuclear as opposed to the CC in 2026.

Table 1-A Duke Energy Kentucky 2011 Resource Plan				
Year	Demand Side[1] (Conservation EE & Demand Response)	Purchases/ Unit Additions	Renewables (Biomass/Wind/Solar)	Cumulative
2011				
2012	3 MW			3 MW
2013	-1 MW			2 MW
2014	4 MW			6 MW
2015	4 MW	New CC (140 MW)		150MW
2016	4 MW		5 MW	159 MW
2017	2 MW		3 MW	164 MW
2018	2 MW		3 MW	169 MW
2019	2 MW			171 MW
2020	2 MW		3 MW	176 MW
2021	2 MW		5 MW	183 MW
2022	2 MW		1 MW	186 MW
2023	2 MW		2 MW	190 MW
2024	2 MW		2 MW	194 MW
2025	3 MW		2 MW	199 MW
2026	1 MW			200 MW
2027	2 MW	New CC (35 MW)		237 MW
2028	2 MW			239 MW
2029	3 MW			242 MW
2030	2 MW			244 MW
2031		New CC (35 MW)		279 MW

Notes:

1. Incremental additions to 37 MWs of existing Demand Response.
2. The renewables MW in Table 1-A represent contribution to peak.

2. OBJECTIVES AND PROCESS

A. INTRODUCTION

This chapter will explain the objectives of, and the process used to develop, the 2011Duke Energy Kentucky Integrated Resource Plan. In this Integrated Resource Planning (IRP) process, the modeling of Duke Energy Kentucky includes the firm electric loads, supply-side and demand-side resources, and environmental compliance measures associated with the Duke Energy Kentucky service territory.

B. OBJECTIVES

The purpose of this IRP is to outline a robust strategy to furnish electric energy services to Duke Energy Kentucky customers in a reliable, efficient, and economic manner while factoring in the uncertainty of the current environment.

The planning process itself must be dynamic and constantly adaptable to changing conditions. The Resource Plan (The Plan) presented herein represents the most robust and economic outcome based upon a various assumptions and sensitivities. Due to the uncertainty of the current environment including regulatory, economic, environmental and operating circumstances, Duke Energy Kentucky has performed sensitivity analysis as part of this IRP to account for these uncertainties. As the environment continues to evolve, Duke Energy Kentucky will continue to monitor and make adjustments as necessary and practical to reflect improved information and changing circumstances.

Duke Energy Kentucky's long-term planning objective is to employ a flexible planning process and pursue a resource strategy that considers the costs and benefits to all stakeholders (customers, shareholders, employees, suppliers, and community). At times, this involves striking a balance between competing objectives. The major objectives of the plan presented in this filing are:

- Provide adequate, reliable, and economic service to customers in an uncertain environment

- Maintain the flexibility and ability to alter the plan in the future as circumstances change
- Choose a near-term plan that is robust over a wide variety of possible futures
- Minimize risks (such as wholesale market risks, reliability risks, *etc.*)

C. ASSUMPTIONS

The analysis performed covers the period 2011-2031, although the primary focus is on the first ten years, and meeting the capacity and energy need in 2015 left by the Miami Fort 6 retirement. This technique was used in order to concentrate on the near-term need while recognizing the fact that as the environment changes, The Plan may be adjusted to according to the changes. The planning period was extended compared to the fifteen-year period required by the IRP rules in order to incorporate a longer period of time with regard to CO_2 restriction impacts.

For this IRP analysis, two different regulatory constructs were evaluated to assess the impact of potential CO_2 or Energy Policy legislation. The first included a CO_2 cap and trade construct with allowance prices beginning in 2016 projected at the lower end of pricing of previous proposed legislation. The second construct was based on Clean Energy Standard where an increasing percentage of retail sales starting in 2015 would come from energy efficiency, renewables, coal generation with carbon sequestration, nuclear and some allowance for combined cycle generation. Detailed descriptions of each of these constructs are available in Chapter 8.

The planning reserve margin used for the 2011 resource plan is 14.5%. The IRP models utilize the full capacity of the unit ratings to perform dispatch, so the reserve margin needs to be developed on an installed capacity rating. This is calculated using following steps.

1. Calculation of the PJM Forecast Pool Requirement based on the unforced capacity (UCAP) of the Duke Energy Kentucky system. This utilizes the PJM average effective forced outage rate and the PJM installed reserve margin based on the installed capacity for the DEOK (Duke Energy Ohio Kentucky) Zone. DEOK is the PJM zone applicable to the Duke Energy Kentucky service territory. Based on future years the Forecast Pool Requirement is 8.27%.
2. The Forecast Pool Requirement based on UCAP is then translated to a Duke Energy Kentucky reserve margin by accounting for the load serving entity's effective forced outage rate. The effective forced outage rate for Duke Energy Kentucky based on 2010 tested values is 9.83% and the resulting reserve margin based on installed capacity is 20.1%. This is the reserve margin that would be applied to the Duke Energy Kentucky peak that is coincident with the PJM peak.
3. For 2011, PJM's forecast assumes that the DEOK zone is 95.3% coincident with the PJM peak. Translating the 20.1% reserve margin applied to the Duke Energy Kentucky peak which is based installed capacity for the coincident PJM peak into a reserve margin used for planning purposes results in a reserve margin of 14.5%.

D. PLANNING PROCESS

The development of the resource plan is a multi-step process involving these key planning functions:

- Develop planning objectives and assumptions.
- Consideration of the impacts of anticipated or pending regulations or events on existing resources (environmental, renewables, etc.).
- Preparation of the electric load forecast. More details of this step may be found in Chapter 3.
- Identification of electric energy efficiency (EE) and demand side management (DSM), options. More details concerning this step can be found in Chapter 4.
- Identification and economic screening for the cost-effectiveness of supply-side resource options. More details concerning this step of the process can be found in Chapter 5.

- Integration of the energy efficiency, renewable, and supply-side options with the existing system and electric load forecast to develop potential resource portfolios to meet the desired reserve margin criteria. More details concerning this step of the process can be found in Chapter 8.
- Performance of detailed modeling of potential resource portfolios to determine the resource portfolio that exhibits the lowest cost (lowest net present value of costs) to customers over a wide range of alternative futures. More details concerning this step of the process can be found in Chapter 8.
- Evaluation of the ability of the selected resource portfolio to minimize price and reliability risks to customers. More details concerning this step of the process can be found in Chapter 8.

Many of the screening steps and the integration step mentioned above involve a comparison to a projected market price for electricity. The analytical methodology also includes the incorporation of sensitivity analysis within the screening stages of the overall analysis. Incorporating sensitivity analysis in the early stages of the analysis provides insight into what conditions must be present to transform a potential resource into being an economic alternative or screening survivor. Generally, if resource parameters must be altered beyond what is judged to be reasonable, the resource is excluded from further analysis. If, however, only minor resource parameter changes from base conditions cause the potential resource to become an economic alternative, the resource is considered in future stages of the analysis.

3. ELECTRIC LOAD FORECAST

A. GENERAL

The electric energy and peak demand forecasts of the Duke Energy Kentucky service territory are prepared each year as part of the planning process by a staff that is shared with other Duke Energy Corp. (Duke Energy) affiliated utilities, using the same methodology. Duke Energy Kentucky does not perform joint load forecasts with non-affiliated utility companies, and the forecast is prepared independently of the forecasting efforts of non-affiliated utilities.

The electric energy forecast is one of the most crucial parts of the IRP process. Customer demand, as forecasted in the electric energy and peak demand forecasts, provides the basis for which the resources and plans are chosen.

B. FORECAST METHODOLOGY

The general framework of the Electric Energy and Peak Load Forecast involves a national economic forecast, a service area economic forecast, and the electric load forecast.

The national economic forecast provides information about the prospective growth of the national economy. This involves projections of national economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, and income. The national economic forecast is obtained from Moody's Analytics, a national economic consulting firm.

Similarly, the history and forecast of key economic and demographic concepts for the service area economy is obtained from Moody's Analytics. The service area economic forecast is used along with the energy and peak models to produce the electric load forecast.

Energy sales projections are prepared for the residential, commercial, industrial, and other sectors. Those components along with electric system losses are aggregated to produce a forecast of net energy.

Tables 3-A and 3-B provide information on the forecasted Duke Energy Kentucky System annual growth rates before and after factoring the impacts of the Company's energy efficiency programs. Both tables reflect peak load projections that have not been reduced for impacts from the Company's demand response programs.

TABLE 3-A

Duke Energy Kentucky System

ELECTRIC ENERGY AND PEAK LOAD

FORECAST: ANNUAL GROWTH RATES BEFORE EE

	2011-2031
Residential MWh	1.1%
Commercial MWh	0.9%
Industrial MWh	1.3%
Net Energy MWh	1.0%
Summer Peak MW	0.9 %
Winter Peak MW	0.8 %

TABLE 3-B

Duke Energy Kentucky System

ELECTRIC ENERGY AND PEAK LOAD

FORECAST: ANNUAL GROWTH RATES AFTER EE

	2011-2031
Residential MWh	0.6%
Commercial MWh	0.6%
Industrial MWh	0.9%
Net Energy MWh	0.6%
Summer Peak MW	0.7 %
Winter Peak MW	0.6 %

The forecast of energy is graphically depicted on Figure 3-1, and the summer and winter peak forecasts are shown on Figures 3-2 and 3-3. These forecasts of energy and peak demand provide the starting point for the development of the IRP.

Figure 3-1

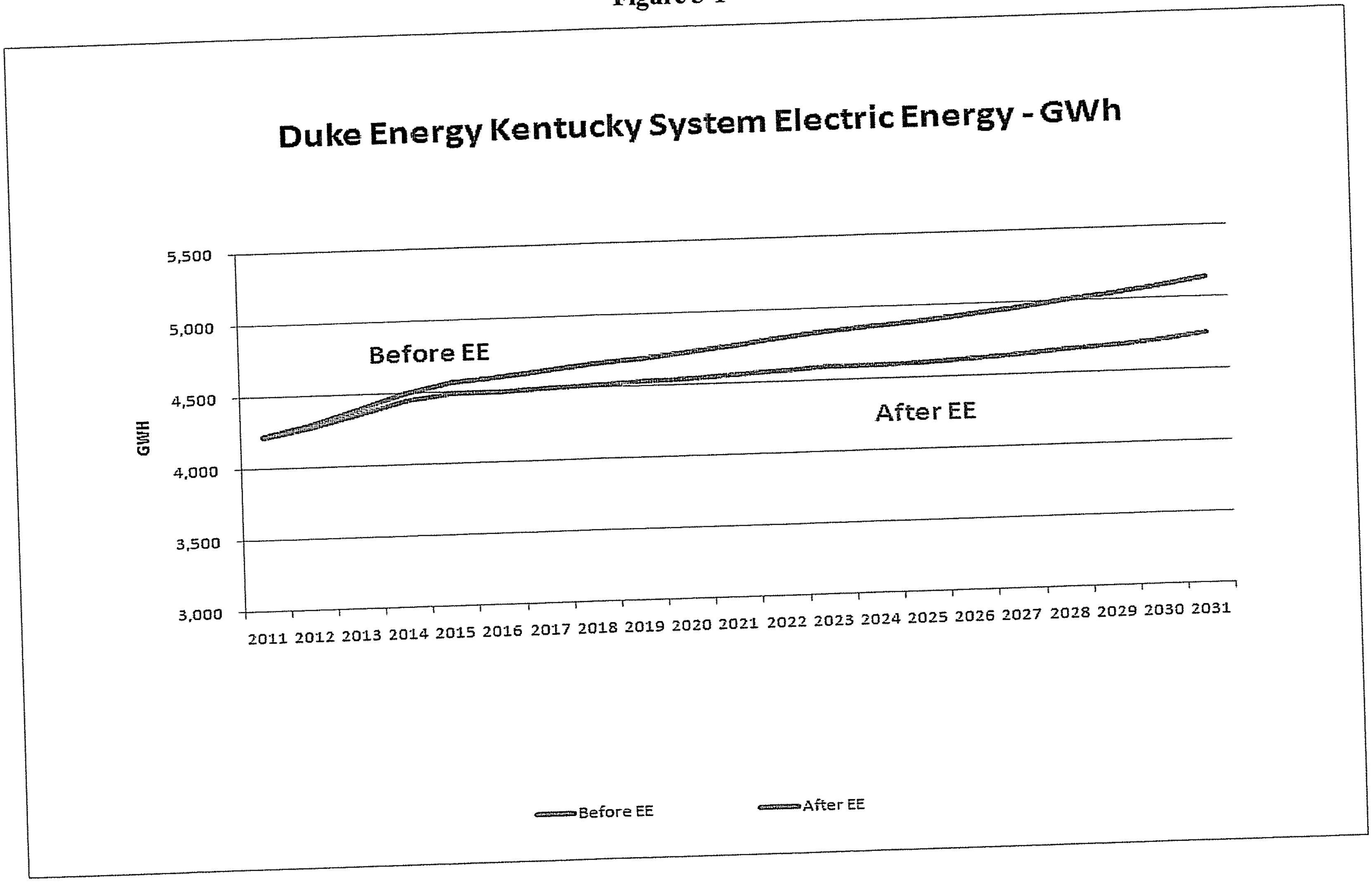

Duke Energy Kentucky System Electric Energy - GWh
5,500
5,000
4,500
4,000
3,500
3,000
GWH
Before EE
After EE
2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Before EE
After EE

Figure 3-2

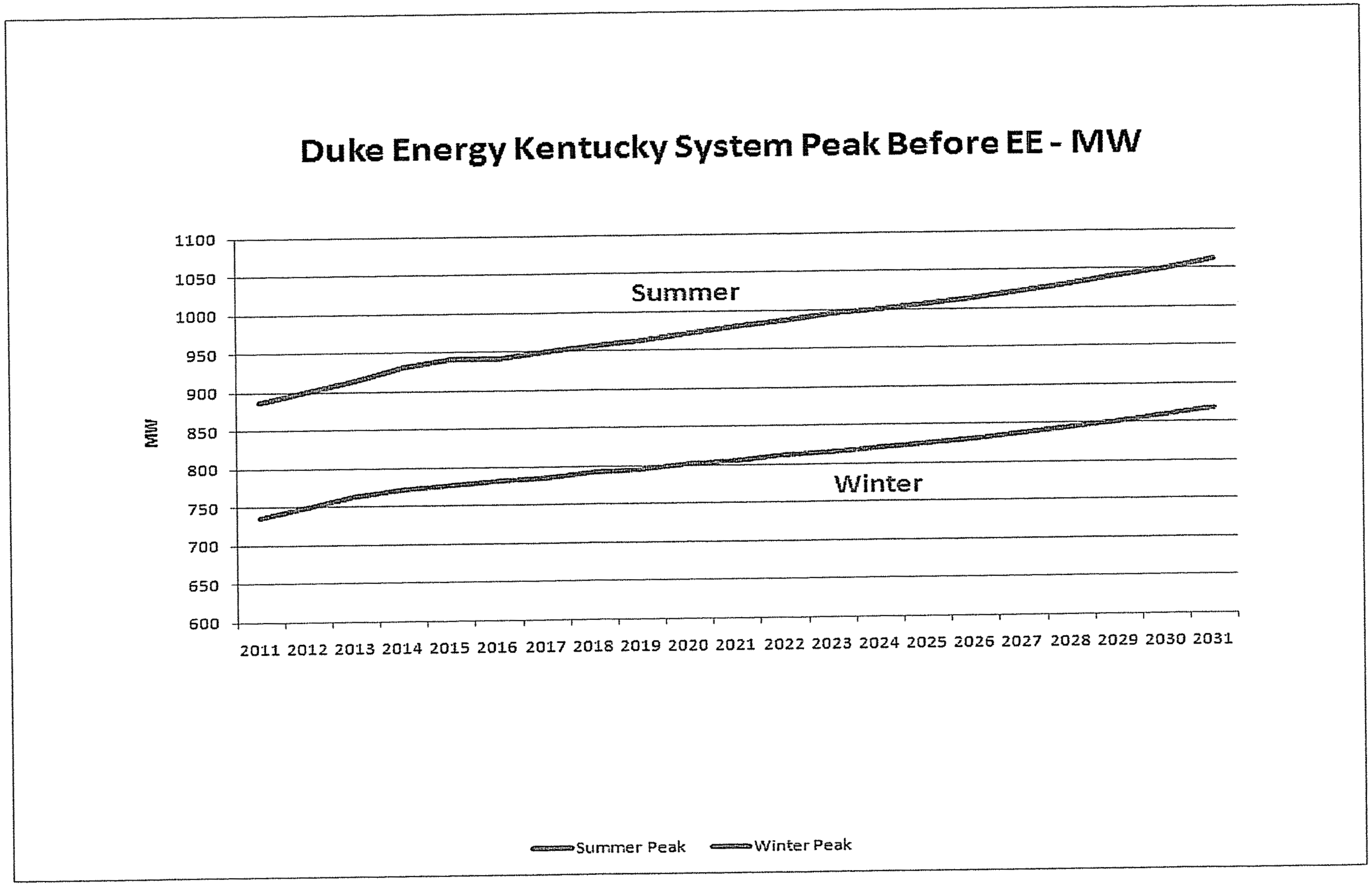
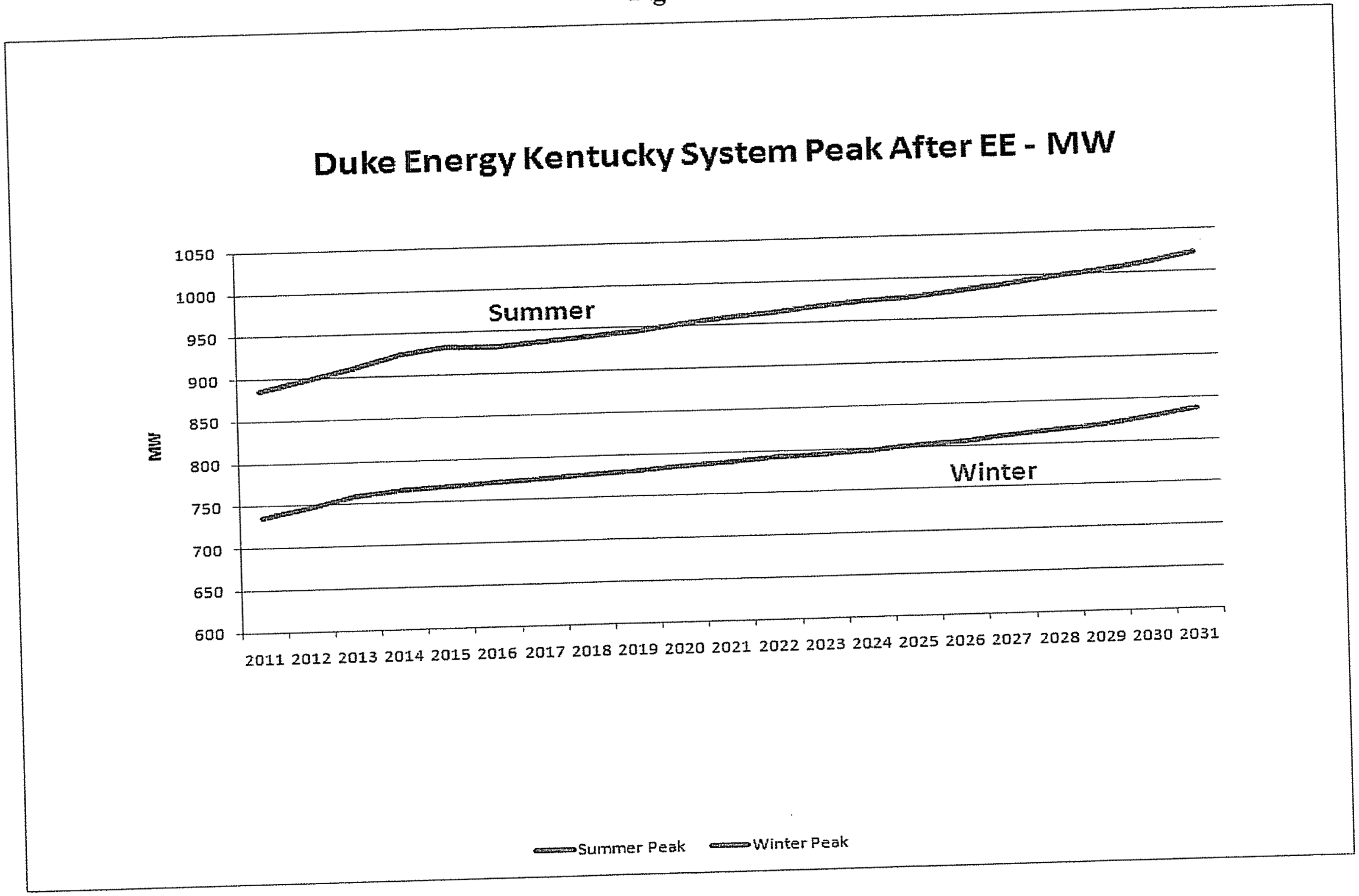

Duke Energy Kentucky System Peak Before EE - MW
MW
1100
1050
1000
950
900
850
800
750
700
650
600
Summer
Winter
2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Summer Peak
Winter Peak

Figure 3-3


Duke Energy Kentucky System Peak After EE - MW
1050
1000
950
900
850
800
750
700
650
600
MW
Summer
Winter
2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Summer Peak
Winter Peak

Actual vs. Forecast

Table 3-C provides information comparing the actual and forecast energy and peak demands (after demand response program impacts) for the Duke Energy Kentucky System. The table compares the actual levels for the years 2006 through 2010 to the forecast developed in the Spring of 2005.

TABLE 3-C

Duke Energy Kentucky System

ELECTRIC ENERGY AND PEAK LOAD

COMPARISON: ACTUAL VS. FORECAST

	Energy - MWH		Internal Peak - MW	
Year	Actual	Forecast	Actual	Forecast
2006	4,248,717	4,134,466	883	916
2007	4,564,528	4,189,016	921	929
2008	4,347,644	4,226,376	860	938
2009	4,045,289	4,262,536	808	948
2010	4,261,952	4,298,510	899	956

All numbers are after energy efficiency.

(Actual energy data is from Table B-2 part 2; actual peak data is from Table B-4)

(Tables B-2 part 2 and B-4 are located in Appendix B)

Changes In Methodology

The Company changed its approach regarding the development of its appliance stock variable to rely more completely on information from Itron, Inc. for estimates of historical appliance efficiency. Because the Company uses the latest historical data available and relies on recent economic data and forecasts from Moody's Analytics the new forecast will be different from the one filed in 2008.

For detailed information on the load forecasting methodology, assumptions, base data documentation, models, forecasted demand and energy, and all load forecast data tables and figures, see Appendix B.

4. DEMAND-SIDE MANAGEMENT RESOURCES

A. INTRODUCTION

Duke Energy Kentucky's demand-side management (DSM) programs include traditional conservation energy efficiency (EE) programs and demand response (DR) programs and are expected to help reduce demand on the Duke Energy Kentucky system during times of peak load.

Through applications by the Company and in conjunction with the Company's DSM Collaborative, the Commission has approved expansions of the Company's DSM efforts over time. The expansion of the programs has led to the implementation of the following set of programs:

Program 1: Residential Conservation and Energy Education
Program 2: Residential Home Energy House Call
Program 3: Residential Comprehensive Energy Education Program (NEED)
Program 4: Program Administration, Development & Evaluation Funds
Program 5: Payment Plus
Program 6: Power Manager
Program 7: Energy Star® Products
Program 8: Energy Efficiency Website
Program 9: Personal Energy Report (PER)
Program 10: C&I High Efficiency Incentive (for Businesses and Schools)
Program 11: PowerShare®

Details on each program are provided in Appendix C.

Under the current DSM Agreement and prior Commission Orders, all of the programs will end December 2012 unless an application is made to continue them. It is the Company's intention to submit a filing subsequent to this report, requesting the approval of a set of energy efficiency and demand response products and services.

B. DSM PROGRAMS AND THE IRP

The projected impacts of the DSM programs discussed above and in detail in Appendix C have been included in the resource plan for Duke Energy Kentucky. The conservation DSM programs are projected to reduce energy consumption by approximately 35,000 MWh and 7 MW by 2017. At the same time, the direct load control program is projected to reduce peak demand by 13 MW and the PowerShare® program another 2 MW. This brings the total peak reduction across all programs to approximately 22 MW by 2017. The following Table 4A summarizes the projected load management impacts included in this IRP analysis.

Table 4-A

Projected Energy Efficiency Load Impacts

Duke Energy Kentucky
Projected Energy Efficiency Load Impacts

Year	Conservation Program Impacts MWH	Conservation Program Impacts MW	Demand Response Program Impacts MW			Total Energy Efficiency Impacts MW
			Power Share	Power Manager	Total	Total
2011	5,198	0.43	26	11	37	37
2012	18,435	2	26	12	38	40
2013	35,134	4	23	12	35	38
2014	53,497	6	25	12	37	43
2015	73,968	8	27	12	40	47
2016	104,508	11	27	13	40	51
2017	124,282	13	27	13	40	53
2018	144,056	15	27	13	40	55
2019	163,830	17	27	13	40	57
2020	183,604	19	27	13	40	59
2021	203,378	21	27	13	40	61
2022	223,152	23	27	13	40	63
2023	242,926	25	27	13	40	65
2024	262,700	27	27	13	40	68
2025	282,474	30	27	13	40	70
2026	302,248	31	27	13	40	71
2027	322,022	33	27	13	40	73
2028	341,795	35	27	13	40	75
2029	361,569	38	27	13	40	78
2030	381,343	40	27	13	40	80
2031	385,184	40	27	13	40	80

Note: the conservation MW program impacts represent the monthly seasonal maximum.

5. SUPPLY-SIDE RESOURCES

A wide variety of supply-side resource options were considered in the screening process. These generally included existing or potential purchases from other utilities, non-utility generation, and new utility-built generating units (conventional, advanced technologies, and renewables).

A. INTRODUCTION

The phrase "supply-side resources" encompasses a wide variety of options that Duke Energy Kentucky uses to meet the energy needs of its customers, both reliably and economically. These options can include existing generating units, repowering options for these units, existing or potential power purchases from other utilities, Independent Power Producers (IPPs) and cogenerators, and new utility-built generating units (conventional, advanced technologies, and renewables). The IRP process assesses the possible supply-side resource options that would be appropriate to meet the system needs by considering their technical feasibility, fuel availability and price, length of the contract or life of the resource, construction or implementation lead time, capital cost, O&M cost, reliability, and environmental effects. This chapter will discuss in detail the specific options considered, the screening processes utilized, and the results of the screening processes.

B. EXISTING UNITS

1. Description

The total installed net summer generation capability owned by Duke Energy Kentucky is 1,077 MW. This capacity consists of 577 MW of coal-fired steam capacity, and 500 MW of natural gas-fired peaking capacity.

Information concerning the existing generating units as of the date of this filing is contained in Table A-3. This table lists the name and location of each station, unit number, type of unit, installation date, tentative retirement year, net dependable summer and winter capability (Duke Energy Kentucky share), and current environmental protection measures. The steam capacity, located at two stations, is comprised of two coal-fired units. The peaking capacity consists of six natural gas-fired Combustion Turbines (CTs) located at one station. These natural gas-fired units have propane as a back-up fuel. East Bend Unit 2, one of the coal-fired steam units, is jointly owned with Dayton Power & Light (DPL) (see Table A-4). Duke Energy Kentucky owns 69% of the unit and is the operator. The approximate fuel storage capacity at each of the generating stations is shown in Table A-5.

2. Availability

The unplanned outage rates of the units used for planning purposes were derived from the historical Generating Availability Data System (GADS) data on these units. Planned outages were based on maintenance requirement projections as discussed below. This IRP assumes that these generating units generally will continue to operate at their present availability and efficiency (heat rate) levels.

3. Maintenance Requirements

A comprehensive maintenance program is important in providing reliable low cost service. The following tabulation outlines the general guidelines governing the preparation of a maintenance schedule for existing units owned by Duke Energy Kentucky. It is anticipated that future units will be governed by similar guidelines.

Scheduling Guidelines for Duke Energy Kentucky Units

1. Major maintenance on baseload units 400 MW and larger is to be performed at about six to ten year intervals (East Bend 2).
2. Major maintenance on intermediate-duty units between 140 MW and 400 MW is to be performed at about six to twelve year intervals (Miami Fort 6).
3. Due to the more limited run-time of other units, judgment and predictive maintenance will be used to determine the need for major maintenance (Woodsdale 1-6).

In addition to the regularly scheduled maintenance outages, beginning in 1999, a program of "availability outages" was instituted. These are unplanned, opportunistic, proactive short duration outages aimed at addressing potential summer reliability. At appropriate times, when it is economic to do so, units may be taken out of service for short periods of time (*i.e.*, less than nine days) to perform maintenance activities. This enhancement in maintenance philosophy reflects Duke Energy Kentucky's focus on having generation available during peak periods (*e.g.*, the summer months). Generating station performance is now measured primarily by reference to how available the station is modified by a comparison of its cost to the market price of electricity. Moreover, targeted, plant-by-plant assessments of the causes of all forced outages that occurred have been performed annually to further focus actions during maintenance and availability outages. Finally, system-wide and plant-specific contingency planning was instituted to ensure an adequate supply of labor and materials when needed, with the goal of reducing the length of any forced outages.

The general maintenance requirements for all of the existing generating units were entered into the models (described in Chapter 8) which were used to develop the IRP.

4. Fuel Supply

Coal

Coal for Duke Energy Kentucky's generating stations is procured by Duke's Regulated Fuels group. Their goal is to provide a reliable supply of fuel in quantities sufficient to meet generating requirements, of the quality required to meet environmental regulations, at the lowest reasonable cost. The "cost" of the coal is the evaluated cost, which includes the purchase price of the coal "freight on board" (FOB) at the shipping point, transportation to the station, the cost of emissions based on the sulfur content, and the effects of the coal quality on station equipment operations.

Duke Energy Kentucky has set broad fuel procurement policies such as contract/spot ratios and inventory levels that aid in contract negotiations. The policies are then combined with economic and market forecasts and probabilistic dispatch models to provide a five-year strategy for fuel purchasing. The strategy provides a guide to meet the goal of having a reliable supply of low cost fuel.

To provide fuel supply reliability, the Regulated Fuels group purchases coal from a dispersed supply area, utilizes a mix of term contract and spot market purchases, and purchases from a variety of proven suppliers. Duke Energy Kentucky maintains stockpiles of coal at each station to guard against short-term supply disruptions. In general, disruptions that could affect the coal supply are evaluated, along with their potential duration and the probability that they will occur. Sufficient coal is then kept on hand to meet those potential supply disruptions.

Coal supplied to Duke Energy Kentucky currently comes primarily from the states of Ohio, Kentucky, and Pennsylvania. These states are rich in coal reserves with decades of remaining economically recoverable reserves.

Duke Energy Kentucky customarily receives approximately 70% to 80% of its annual coal requirements under long-term coal supply agreements. Contract commitments offer greater reliability than spot market purchases. The financial stability, managerial integrity, and overall reliability of the suppliers is evaluated prior to entering into a contractual commitment. Dedicated, proven reserves assure coal supply of the specified quantity and quality. Specified pricing, delivery schedules, and length of contract provide suppliers with the financial stability for capital investment and labor requirements and guard Duke Energy Kentucky against primarily upward price fluctuations in the market. This is accomplished using a combination of low fixed-escalation, market price re-openers, and contract extension options.

The remainder of Duke Energy Kentucky's fuel need is filled with spot coal purchases. Spot coal purchases are used to:

1) take advantage of low-priced incremental tonnage
2) test new coal supplies
3) supplement coal during peak periods or during contract delivery disruptions.

Natural Gas

Duke Energy Kentucky's use of natural gas for electric generating purposes has been limited to peaking applications. This natural gas is currently purchased in the spot market and is transported (delivered) using interruptible transportation contracts. The low capacity factor associated with this type of application make contracting for firm gas and transportation non-economic. The gas supply for Woodsdale is managed under a Fuel Supply and Management Agreement with a third party supplier, Sequent Energy Management LP (Sequent). Sequent supplies the full requirements of natural gas needed by Woodsdale either by purchasing gas from third parties as an agent or by selling gas owned or controlled by Sequent. Duke Energy Kentucky pays Sequent a market price for all gas supply purchases. The Fuel Supply and Management Agreement allows Duke Energy Kentucky to purchase gas supply from a 3rd party if they are not able to agree on a price with Sequent.

Propane

At Woodsdale, propane is used as the back-up fuel in case natural gas is unavailable or as a hedge against high natural gas prices. A Propane Services Agreement with TEPPCO LLC (TEPPCO) provides Duke Energy Kentucky the ability to purchase propane at market prices. Woodsdale can pull propane from storage owned by Duke Energy Kentucky, where 48,000 barrels of propane storage space is available or use up to 40,000 barrels of propane from TEPPCO on loan for replacement within 45 days.

Oil

At East Bend and Miami Fort 6, Duke Energy Kentucky uses fuel oil for starting coal-fired boilers and for flame stabilization during low load periods. Oil supplies are expected to be sufficient to meet these relatively low volume needs for the foreseeable future.

Duke Energy Kentucky's Fuels Department monitors potential changes in the fuel industry including mining methodologies, and the availability of different fuels. To the extent that any of these potential changes has an influence on the IRP, they have been incorporated.

The focus of Duke Energy Kentucky's fuel-related R&D efforts is to develop leading-edge technologies and provide information, assessments, and decision-making tools to support fossil power plants in reducing their costs for fuel utilization and managing environmental risk.

5. Fuel Prices

The coal and gas prices for both existing and new units utilized in this IRP were developed using a combination of observable forward market prices and long-term commodity price fundamentals. The observable forward markets includes data from public exchanges like the NYMEX, as well as fuel contracts and price quotes from fuel providers in response to regular Duke Energy fuel supply RFP's. The Duke Energy long-term fundamental forecast is a proprietary forecast developed for Duke Energy by Wood Mackenzie, a leading energy consulting firm. The assumptions used in the development of the Duke Energy fundamental forecast were developed by both Wood Mackenzie and Duke Energy in-house subject matter experts. The Duke Energy long-term fundamental forecast is approved annually by the Duke Energy Leadership staff for use in all long-term planning studies and project evaluations.

6. Condition Assessment

Duke Energy Kentucky continues to implement its engineering condition assessment programs as described in more detail in part 9 (Age of Units) below. The intent is to maintain the generating units, where economically feasible, at their current levels of efficiency and reliability.

7. Efficiency

Duke Energy Kentucky evaluates the cost-effectiveness of maintenance options on various individual components of the existing generating units. If the potential maintenance options prove to be cost-justified, they are budgeted and generally undertaken during a future scheduled unit maintenance outage. However, due to modeling limitations, the large number and wide-ranging impacts of these individual options made it impossible to include these numerous smaller-scale options within the context of the IRP integration process. The routine economic evaluation of these smaller-scale options is consistent with that utilized in the overall IRP process. As a result, the outcome and validity of this plan have not been affected by this approach.

However, any plans to increase fossil fuel generation efficiency must be viewed in light of regulatory requirements, specifically the EPA's new source review (NSR) rules. These regulatory requirements are subject to interpretation and change over the years. Within the context of such requirements, Duke Energy Kentucky plans routine maintenance projects, which may maintain or increase the efficiency of its generating units. All of these plans are subject to change depending on the changing regulatory environment and rules related to NSR.

The technology available to meet environmental regulations adds constraints to the power plant fuel cycle and also requires energy to operate. The net result is a reduction in the load capability and a lower overall efficiency. This loss in capability must be replaced by newly acquired resources, by off-system purchased power, or by the increased operation of less efficient units. On either a system or regional basis, lost capacity ultimately translates into a cost for new resources to replace the reduction in capacity.

Likewise, one potential effect of meeting environmental regulations can be to degrade the reliability (*i.e.*, the availability) of each generating unit by increasing the complexity of the overall system. This could translate into a cost to replace the unavailable capacity in terms of new resource acquisitions.

8. Age of Units

Miami Fort Unit 6 is 48 years old and East Bend Unit 2 is 27 years old. As previously mentioned, Miami Fort Unit 6 is being considered for retirement in the 2015 timeframe. The primary driver for the retirement date is the recently proposed United States Environmental Protection Agency (EPA) Utility Maximum Achievable Control Technology (MACT) rule. The rule is expected to be finalized in November 2011, with required control technologies to be installed by January 1, 2015. However, the multiple emerging environmental regulations (including the new water quality standards, fish impingement and entrainment standards, Coal Combustion Residuals (CCR) rule and the new Sulfur Dioxide (SO_2), Particulate Matter (PM) and Ozone National Ambient Air Quality Standards) together drive the expected retirement of the unit.

Generating unit age alone is not the sole identifier for the likelihood of equipment failure. It is generally true that older generating units have increased probability of failure of any given component due to wear-and-tear over its lifetime. It is also generally true, however, that newer units, while having less equipment wear-and-tear, are more complex (such units are generally larger and thus have more components, and are more commonly equipped with modern environmental controls such as cooling towers, and FGD and SCR systems). How generating units are operated (*i.e.*, operation within manufacturers recommended specifications; cycling duty; ramp rate, *etc.*) and maintained throughout their economic lifetime also helps to determine the likelihood of a failure event. Thus, how a generating unit is initially designed, constructed, as well as operated, and maintained during its lifetime, all play a role in the probability of failure.

As discussed earlier, Duke Energy Kentucky routinely monitors the efficiency and availability of its generating units. Based on those observations, projects that are intended to maintain the long-term performance of the units are planned, evaluated, selected, budgeted, and executed. Duke Energy Kentucky performs routine maintenance activities on its generating units to maintain the efficiency and reliability of those units at current levels. Using standard industry practices, generating unit support and auxiliary equipment and/or sub-systems that are nearing their normal useful lives are identified and repaired, prior to failure and the resultant loss of overall unit availability. Examples of such practices might include: vibration monitoring, lube oil analyses, visual inspections, including boroscopic inspection of difficult-to-access areas; non-destructive examination (NDE) such as boiler tube thickness measurement surveys, dye-penetrate crack testing, eddy-current thickness testing, and nuclear material analysis; and sometimes even destructive examinations such as taking boiler tube samples or high-energy piping "boat" samples. All of these methods of monitoring are intended to identify equipment condition so that equipment failure can be predicted and avoided.

Using such monitoring and testing methods, along with manufacturer-recommended operating practices, and diligent maintenance practices, a given generating unit may continue operating reliably and efficiently for many years. Even under such conditions, however, instances of unanticipated equipment failure still occur. Normally, though, such events do not result in a significant loss of unit availability (more than two weeks of unit outage). Rarely in the industry does a catastrophic failure result in the permanent complete loss of a generating asset.

Finally, few technological breakthroughs have occurred relating to coal-fired steam units since the early-1950s, before which times the efficiency of the generally much smaller units (less than 100 MW) without re-heat steam cycles may have forced generating units into technological obsolescence. Supercritical steam cycles offered some incremental improvements to unit efficiencies since the 1950s, but because coal costs are lower and historically less volatile than more premium fuel types, these changes were not enough to force technological obsolescence.

C. EXISTING NON-UTILITY GENERATION

Duke Energy Kentucky does not currently have any contracts with non-utility generators.

Some of Duke Energy Kentucky's customers have electric production facilities for self-generation, peak shaving, or emergency back-up. Non-emergency self-generation facilities are normally of the baseload type and are generally sized for reasons other than electric demand (*e.g.*, steam or other thermal demands of industrial processes or heating). Peak shaving equipment is typically oil- or gas-fired and generally is used only to reduce the customer's peak billing demand. Depending on whether it is operated at peak, this capacity can reduce the load otherwise required to be served by Duke Energy Kentucky which, like DSM programs, also reduces the need for new capacity. Some of these customers are participants in Duke Energy Kentucky's PowerShare® program which was discussed in Chapter 4.

Customers make cogeneration decisions based on their particular economic situations, so Duke Energy Kentucky does not attempt to forecast specific Megawatt levels of cogeneration activity in its service area. Cogeneration facilities built to affect customer energy and demand served by the utility are captured in the load forecast. Cogeneration built to provide supply to the electric network represents additional regional supply capability. As purchase contracts are signed, the resulting energy and capacity supply will be reflected in future plans.

D. EXISTING POOLING AND BULK POWER

At present, Duke Energy Kentucky does not participate in any formal type of power pooling. Duke Energy Kentucky co-owns East Bend Unit 2 with DPL. Miami Fort Unit 6 is located at the Miami Fort Station, at which Duke Energy Ohio owns additional coal-fired units and several CTs.

Duke Energy Midwest is interconnected directly with East Kentucky Power Cooperative, Inc., Louisville Gas and Electric / Kentucky Utilities, American Electric Power, DPL, Ohio Valley Electric Corporation, Ameren, Hoosier Energy, Indianapolis Power and Light, Northern Indiana Public Service, and Southern Indiana Gas and Electric, and indirectly with the Tennessee Valley Authority.

Duke Energy Kentucky routinely meets with utilities in the region generally to discuss the daily interconnection operations, opportunities for short-term energy transactions which may be beneficial to both parties, and the long term purchase/sale of capacity as an alternative to the construction/operation of additional generation facilities.

Duke Energy Kentucky will operate within PJM consistent with its intention to transfer the Duke Energy Kentucky transmission assets from the MISO to PJM effective January 1, 2012.

E. NON-UTILITY GENERATION AS FUTURE RESOURCE OPTIONS

It is Duke Energy Kentucky's practice to cooperate with potential cogenerators and independent power producers. A major concern, however, exists in situations where either customers would be subsidizing generation projects through higher than avoided cost buyback rates, or the safety or reliability of the electric system would be jeopardized. Duke Energy Kentucky typically receives several requests a year for independent/small power production and cogeneration buyback rates. Duke Energy Kentucky does not currently have any contracts for cogeneration. However, Duke Energy Kentucky has two cogeneration tariffs available to customers. Duke Energy Kentucky will supply any customer interested in cogeneration with a copy of these tariffs and will discuss options with that customer.

A customer's decision to self-generate or cogenerate is, of course, based on economics. Customers know their costs, profit goals, and competitive positions. The cost of electricity is just one of the many costs associated with the successful operation of their business. If customers believe they can lower their overall costs by self-generating, they will investigate this possibility on their own. There is no way that a utility can know all of the projected costs and/or savings associated with a customer's self-generation. However, during a customer's investigation into self-generation, the customer usually will contact the utility for an estimate of electricity buyback rates. With Duke Energy Kentucky's comparatively low electricity rates and avoided cost buyback rates, cogeneration and small power production are generally uneconomical for most customers.

For these reasons, Duke Energy Kentucky does not attempt to forecast specific megawatt levels of this activity. Cogeneration facilities built to affect customer energy and demand served by the utility are captured in the load forecast. Cogeneration built to provide supply to the electric network represents additional regional supply capability. As purchase contracts are signed, the resulting energy and capacity supply will be reflected in future plans. The electric load forecasts discussed in Chapter 3 considers the impacts on electricity consumption caused by the relative price differences between alternate fuels (such as oil and natural gas) and electricity. If the relative price gap favors alternate fuels, electricity is displaced, lowering the forecasted use of electricity and increasing the use of the alternate fuels. Some of the decrease in forecasted electricity consumption may be due to self-generation/cogeneration projects, but the exact composition cannot be determined.

Duke Energy has direct involvement in the cogeneration area. Duke Energy Generation Services, an unregulated affiliate of Duke Energy Kentucky, builds, owns, and operates cogeneration and trigeneration facilities for industrial plants, office buildings, shopping centers, hospitals, universities, and other major energy users that can benefit from combined heating/cooling and power production economies.

Other supply-side options such as simple-cycle CTs, Combined Cycle (CC) units, coal-fired units, and/or renewables (all discussed later in this chapter) could represent potential non-utility generating units, power purchases, or utility-constructed units. Each of these options will be considered when Duke Energy Kentucky pursues the acquisition of new capacity.

F. SUPPLY-SIDE RESOURCE SCREENING

A diverse range of technology choices utilizing a variety of different fuels was considered including pulverized coal units with and without carbon capture sequestration, Integrated Gasification Combined Cycle (IGCC) with and without carbon capture sequestration, CTs, CC units, and nuclear units. In addition, renewable technologies such as wind, biomass, and solar received a focus in this year's screening analysis.

For the 2011 IRP screening analyses, technology types were screened within their own general category of baseload, peaking/intermediate, and renewable, with the ultimate goal of screening being to pass the best alternatives from each of these three categories to the integration process, as opposed to, for instance, having all renewable technologies screened out because they didn't fare well against the more conventional technologies on the final screening curve. As in past years, the reason for performing these initial screening analyses is to determine the most viable and cost-effective resources for further evaluation. This is necessary because of the computer execution time limitations of the System Optimizer capacity model (described in detail in Chapter 8).

1. Process Description

Information Sources

The cost and performance data for each technology being screened are based on research and information from several sources. These sources include internal subject matter experts and the EPRI Technology Assessment Guide (TAG®), studies performed by and/or information gathered from external sources. In addition, fuel and operating cost estimates are developed internally by Company personnel, or from other sources such as those mentioned above, or a combination of the two. The EPRI information along with any information or estimates from external studies are not site-specific, but generally reflect the costs and operating parameters for installation in the Midwest.

Finally, every effort is made to ensure, as much as possible, that the cost and other parameters are current and include similar scope across the technology types being screened. While this has always been important, keeping cost estimates across a variety of technology types consistent in today's construction material, manufactured equipment, and commodity markets, remains very difficult. The fluctuation of the escalating prices in these markets often makes cost estimates and other price/cost information out-of-date in as little as six months. In addition, vendor quotes and/or other estimates once relied upon as being a good indicator of, or basis for, the cost of a generating project, may have lives as short as 60 days.

Technical Screening

The first step in the supply-side screening process was a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy Kentucky service territory. A brief explanation of the technologies excluded at this point and the logic for their exclusion follows:

- Geothermal was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project.
- Advanced Battery storage technologies (Lead acid, Li-ion, Sodium Ion, Zinc Bromide, Fly wheels, pump storage) remain relatively expensive and are generally suitable for small-scale emergency back-up and/or power quality applications with short-term duty cycles of three hours or less. In addition, the current energy storage capability is generally 100 MWh or less. Research, development, and demonstration continue within Duke Energy, but this technology is generally not commercially available on a larger utility scale. Currently Duke Energy is installing 36 MW advanced acid lead batteries at the Notrees wind farm in Texas that is scheduled for start-up in 2012 to learn more about energy storage. Duke Energy has other storage system test stations at the Envision Energy Center in Charlotte, specifically two Community Energy Storage (CES) storage systems at 24 KWh.
- Compressed Air Energy Storage (CAES) although demonstrated on a utility scale and generally commercially available, is not a widely applied technology and remain relatively expensive. This is due to the fact that suitable sites that possess the proper geological formations and conditions necessary for the compressed air storage reservoir are relatively scarce.
- Small and medium nuclear reactors are generally limited to less than 500 MW. The Nuclear Regulatory Commission (NRC) has not licensed any smaller nuclear reactor designs at this point in time. Several designs including those by GE, B&W and Westinghouse may seek licensing in 2012 and 2013.
- Fuel Cells, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power

generation systems. The size of the distributed generation applications range from a few kilowatts to tens of megawatts in the long-term. Cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially available for utility-scale application.

- Poultry waste and hog waste digesters remain relatively expensive and are capable of generating 500 – 600 MWh or less. Research, development, and demonstration continue, but these technologies are generally not commercially available on a larger utility scale.
- Off-Shore Wind, although demonstrated on a utility scale and commercially available, is not a widely applied technology and not easily permittable. This technology remains relatively expensive.
- Combined Cycle G-Class demonstrated on a utility scale is comparable to the F-Class with efficiency and remains limited with lack of experience. The Combined Cycle G-Class technology is larger in size and is designed to operate primarily as base load and not suitable for the anticipated cycling operation.

The interest in clean air emissions has led to a deeper investigation into renewable technologies. The renewable technologies that were added to the screening analyses for this IRP include:

- Fluidized Bed Biomass
- Solar Photovoltaic
- Wind

Economic Screening

In the supply-side screening analysis, the fuel prices for coal and gas and emission allowance prices were the same as those utilized in the System Optimizer analysis (discussed in Chapter 8). The biomass fuel price was derived from various vendor fuel and delivery prices. The biomass fuel price may vary in the future as more utilities begin to use biomass fuel to co-fire. The technologies were screened using relative dollar per kilowatt-year versus capacity factor screening curves. The screening within each general class, as well as the final screening across the general classes, used a spreadsheet-based screening curve model developed by Duke Energy. This model is considered confidential and competitive information by Duke Energy.

This screening curve analysis model calculates the fixed costs associated with owning and maintaining a technology type over its lifetime and computes a levelized fixed $/kW-year value. This value represents the cost of operating the technology at a zero capacity factor or not at all, *i.e.*, the Y-intercept on the graph (see the General Appendix for individual graphs). Then the variable costs, such as fuel, variable O&M, and emission costs associated with operating the technology at 100% capacity factor, or at full load, over its lifetime are calculated and the present worth is computed back to the start year. This levelized operating $/kW-year is added to the levelized fixed $/kW-year value to arrive at a total owning and operating value at 100% utilization in $/kW-year. Then a straight line is drawn connecting the two points. This line represents the technology's "screening curve".

This process is repeated for each supply technology to be screened resulting in a set of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations. Some of the renewable resources that have known limited energy output, such as wind and solar, have screening curves limited to their expected operating range on the individual graphs.

Lines that never become part of the lower envelope, or those that become part of the lower envelope only at capacity factors outside of their relevant operating ranges, have a very low probability of being part of the least cost solution, and generally can be eliminated from further analysis.

2. Screening Results

The results of the screening within each category are discussed in more detail below[1]. The technologies were screened with consideration of CO_2 emissions.

Baseload Technologies

Figure A-1 in Appendix A shows the screening curves for the baseload category of screening. Nuclear becomes economic compared to Integrated Gasification Combined Cycle at about 30% capacity factor. The capital and operating costs for carbon capture technology are still the subjects of ongoing industry studies and research, along with the feasibility and costs of geological sequestration of CO_2 once it is captured. The following technologies are found on this chart:

1) 2x1,117 MW Nuclear
2) 800 MW Supercritical Coal
3) 800 MW Supercritical Coal with Carbon Capture and Storage 1- Stage Carbon Monoxide Shift (60% CO_2 control)
4) 800 MW Supercritical Coal with Carbon Capture and Storage 2- Stage Carbon Monoxide Shift (90% CO_2 control)
5) 630 MW IGCC Coal
6) 630 MW IGCC with Carbon Capture and Storage 1- Stage Carbon Monoxide Shift (60% CO_2 control)
7) 630 MW IGCC with Carbon Capture and Storage 2- Stage Carbon Monoxide Shift (90% CO_2 control)

[1] While these estimated levelized screening curves provide a reasonable basis for initial screening of technologies, simple levelized screening has limitations. In isolation, levelized cost information has limited applicability in decision-making because it is highly dependent on the circumstances being considered. A complete analysis of feasible technologies must include consideration of the interdependence of the technologies and Duke Energy Kentucky's existing generation portfolio, as is performed within the System Optimizer and Planning and Risk analyses.

Peak / Intermediate Technologies

Figure A-2 in Appendix A shows the screening curves for the peak / intermediate category. The simple-cycle CT unit makes up the lower envelope of the curves up to about 35% capacity factor, at which time the unfired CC is the most economic over the rest of the capacity factor range.

Duct firing in a CC unit is a process to introduce more fuel (heat) directly into the combustion turbine exhaust (waste heat) stream, by way of a duct burner, to increase the temperature of the exhaust gases entering the Heat Recovery Steam Generator (HRSG). This additional heat allows the production of additional steam to produce more electricity in the steam (bottoming) cycle of a CC unit. It is a low cost ($/kW installed cost) way to increase power (MW) output during times of very high electrical demands and/or system emergencies. However, it adversely impacts the efficiency (raises the heat rate) and thereby dramatically increases the operating cost of a CC unit (notice the much steeper slope of the duct firing "On" cases in the screening curve figures). Duct firing also increases emissions, generally resulting in a very limited number of hours per year that duct firing is allowed within operating permits.

Within the screening curves, the estimated capital cost for a combined cycle unit always includes the duct burner and related equipment. The two curves, one "On," and one "Off," are intended to show the efficiency loss (steeper slope) when the duct burner is "On", but also show that even with the duct burner "On" the efficiency (slope) is still better than a simple-cycle CT unit (much steeper slope). The duct burner "Off" curve is where the combined cycle unit will operate most of the time, and this is the one best compared with all other candidate technologies. The following technologies are found on this chart:

1) 4x204 MW Simple-Cycle CT
2) 460 MW Unfired + 150 MW Duct Fired + 40 MW Inlet Evaporative Cooler Combined Cycle (650MW total)
3) 460 MW Unfired +150 MW Duct Fired (Off)+ 40 MW Inlet Evaporative Cooler Combined Cycle (500 MW total)

Renewable Technologies

Figure A-3 in Appendix A shows the screening curves for the renewable category of screening. One must remember that busbar charts comparisons involving some renewable resources, particularly wind and solar resources, can be somewhat misleading because these resources do not contribute their full installed capacity at the time of the system peak[2]. Since busbar charts attempt to levelize and compare costs on an installed kW basis, wind and solar resources appear to be more economic than they would be if the comparison was performed on a peak kW basis.

Since these renewable technologies either have no CO_2 emissions or are deemed to be carbon neutral, the cost of CO_2 emissions does not impact their operating cost. Wind appears to be the least cost renewable alternative through its maximum practical capacity factor range. Woody biomass is next throughout its entire capacity range. The Solar Photovoltaic is the most costly renewable within the renewable category. The following technologies are found on this chart:

1) 150 MW Wind
2) 25 MW Solar Photovoltaic
3) 100 MW Woody Biomass

3. Unit Size

The unit sizes selected for planning purposes generally are the largest technologies available today because they generally offer lower $/kW installed capital costs due to economies of scale. However, the true test of whether a resource is economic depends on the economics of an overall resource plan that contains that resource (including fuel costs, O&M costs, emission costs, *etc.*), not merely on the $/kW cost. In the case of very large unit sizes such as those utilized for the Nuclear and/or

[2] For purposes of this IRP, wind resources are assumed to contribute 15% of installed capacity at the time of peak and solar resources are assumed to contribute 70% of installed capacity at the time of peak.

IGCC technology types, if these are routinely selected as part of a least cost plan, joint ownership can and may be pursued.

4. Cost, Availability, and Performance Uncertainty

Supply-side alternative project scope and estimated costs used for planning purposes for conventional technology types such as simple-cycle CT units and CC units are relatively well known and are estimated in the TAG® and can be obtained from architect and engineering (A&E) firms and/or equipment vendors. Duke Energy's experience is also used to confirm their reasonability. The cost estimates include step-up transformers and a substation to connect with the transmission system. Since any additional transmission costs would be site-specific and since specific sites requiring additional transmission are unknown at this time, typical values for additional transmission costs were added to the alternatives. The unit availability and performance of conventional supply-side options is also relatively well known and the TAG®, A&E firms and/or equipment vendors are sources of estimates of these parameters.

5. Lead Time for Construction

The estimated construction lead time and the lead time used for modeling purposes for the proposed simple-cycle CT units is about two years. For the CC units, the estimated lead time is about two to three years. For coal units, the lead time is approximately five years. However, the time required to obtain regulatory approvals and environmental permits adds uncertainty to the process, so judgment is used also.

6. RD&D Efforts and Technology Advances

New energy and technology alternatives are needed to ensure a long-term sustainable electric future. Duke Energy Midwest's research, development, and delivery (RD&D) activities enable Duke Energy Midwest to track new options including modular and potentially dispersed generation systems (small and medium nuclear reactors), CTs, and advanced fossil technologies. Emphasis is placed on providing information, assessment tools, validated technology, demonstration / deployment support, and RD&D

investment opportunities for planning and implementing projects utilizing new-power generation technology to assure a strategic advantage in electricity supply and delivery. Duke Energy is also a member of EPRI.

Within the horizon of this forecast, it is expected that advances will continue to be made in CT technology. Advances in stationary industrial CT technology should result from ongoing research and development efforts to improve both commercial and military aircraft engine efficiency and power density, as well as expanding research efforts to burn more hydrogen-rich fuels. The ability to burn hydrogen-rich fuels will enable very high levels of CO_2 removal and shifting in the syngas utilized in IGCC technology, thereby enabling a major portion of the advancement necessary for a significant reduction in the carbon footprint of this coal-based technology.

7. Coordination With Other Utilities

Decisions concerning coordinating the construction and operation of new units with other utilities or entities are dependent on a number of factors including the size of the unit versus each utility's capacity requirement and whether the timing of the need for facilities is the same. To the extent that units that are larger than needed for Duke Energy Kentucky requirements become economically viable in a plan, co-ownership can be considered at that time. Coordination with other utilities can also be achieved through purchases and sales in the bulk power market.

6. ENVIRONMENTAL COMPLIANCE

Duke Energy Kentucky is required to comply with numerous state and federal regulations. In addition to current programs and regulatory requirements several new regulations are in various stages of implementation and development that will impact operations for Duke Energy Kentucky in the coming years. Table 6-A summarizes EPA's current regulatory schedule and Table 6-B provides the anticipated control requirements provided at the end of this discussion. Some of the major rules include:

A. CLEAN AIR INTERSTATE RULE (CAIR) AND REPLACEMENT CAIR – THE TRANSPORT RULE

The EPA finalized its Clean Air Interstate Rule (CAIR) in May 2005. The CAIR limits total annual and summertime NO_X emissions and annual SO_2 emissions from electric generating facilities across the Eastern U.S. through a two-phased cap-and-trade program. Phase 1 began in 2009 for NO_X and in 2010 for SO_2. In December 2008, the D.C. Circuit issued a decision remanding CAIR to the EPA, allowing CAIR to remain in effect as an interim solution until EPA develops new regulations.

In August 2010, EPA published a proposed replacement rule for CAIR, known as the Transport Rule (TR). The TR is expected to be finalized in mid-2011. In the TR, EPA is proposing to establish state-level annual SO_2 caps and annual and ozone season NO_X caps that would take effect in 2012. Further restrictions on SO_2 emissions for Phase II implementation are expected to begin in 2014. Future TRs are also expected that would incorporate the more stringent National Ambient Air Quality Standards (NAAQS), which are in varying stages of development and are discussed later in this document.

B. UTILITY BOILER MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY (MACT) OR EPA'S TOXICS RULE

In May 2005, the EPA issued the Clean Air Mercury Rule (CAMR). The rule established mercury emission-rate limits for new coal-fired steam generating units. It also established a nationwide mercury cap-and-trade program covering existing and new coal-fired power units.

In February 2008 the D.C. Circuit Court of Appeals issued its opinion, vacating the CAMR. EPA has begun the process of developing a rule to replace the CAMR. The replacement rule, the Utility Boiler MACT, will create emission limits for hazardous air pollutants (HAPs), including mercury. Duke Energy Kentucky performed work in 2010 as required for EPA's Utility MACT Information Collection Request (ICR). The ICR required collection of mercury and HAPs emissions data from Duke Energy Kentucky's East Bend Station.

EPA published its proposed Utility MACT rule or the Toxics Rule, as it is now referred to, in early May 2011 and expects to finalize it in November 2011. The Toxics rule is expected to require compliance with new emission limits by 2015. The expected impacts to existing coal-fired generation includes, additional continuous emission monitors, reagent injection, the potential for upgrades or new particulate control devices and if not feasible, potential unit retirements.

C. NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS)

1. 8 Hour Ozone Standard

In March 2008, EPA revised the 8 Hour Ozone Standard by lowering it from 84 to 75 parts per billion (ppb). In September of 2009, EPA announced a decision to reconsider the 75 ppb standard in response to a court challenge from environmental groups and their own belief that a lower standard was justified. A proposed rule was issued by the EPA in January 2010 in which EPA proposed to replace the existing 84 ppb standard with a new standard between 60 and 70 ppb. EPA must finalize the rule by the end of July 2011. State Implementation Plans (SIP) will be due by the end of 2014, with attainment dates for most areas possibly in the 2017 to 2018 timeframe. Any new controls may have to be in-place prior to the 2017 ozone season. Until the states develop implementation plans, only an estimate of the potential impact to Duke Energy Kentucky's generation can be developed. With a standard in the 60 to 70 ppb range, Duke Energy Kentucky facilities may require the installation of the best performing NO_X controls such as Selective Catalytic Reduction (SCR) on units that do not currently operate them.

2. SO_2 Standard

In November 2009, the EPA proposed a rule to replace the current 24-hour and annual primary SO_2 NAAQS with a 1-hour SO_2 standard. A new 1-hour standard of 75 ppb was finalized in June 2010. States with non-attainment areas will have until January 2014 to submit their SIPs. Initial attainment dates are expected to be the summer of 2017 with any required controls in place by late-2016. EPA will base its nonattainment designations on monitored air quality data as well as on dispersion modeling. All Kentucky power plants will be modeled by the State and are therefore potential targets for additional SO_2 reductions, even if there is no monitored potential to exceed the standard.

In addition, EPA is proposing to require States to relocate some existing monitors and to add new monitors. While these monitors will not be used by EPA to make the initial nonattainment designations, they will play a role in identifying possible future nonattainment areas.

D. GREEN HOUSE GAS REGULATION

The US EPA has been active in the regulation of greenhouse gases (GHGs). In May 2010 the EPA finalized what is commonly referred to as the Tailoring Rule, which sets the emission thresholds to 75,000 tons/year of CO_2e for determining when a source is potentially subject to Prevention of Significant Deterioration (PSD) permitting for greenhouse gases. The Tailoring Rule went into effect beginning January 2, 2011. Being subject to PSD permitting requirements for CO_2e will require a Best Available Control Technology (BACT) analysis and the application of BACT for GHGs. BACT will be determined by the state permitting authority. Since it is not known if, or when, a Duke Energy Kentucky generating unit might undertake a modification that triggers PSD permitting requirements for GHGs and exactly what might constitute BACT, the potential implications of this regulatory requirement are unknown.

On December 23, 2010, EPA entered into a proposed settlement agreement to issue New Source Performance Standards for GHG emissions from new and modified fossil fueled electric generating units (EGUs) and emission guidelines for existing EGUs that do not undergo a modification. The agreement calls for regulations to be proposed by July 26, 2011 and to be finalized by May 26, 2012.

Passage of any federal climate change legislation is not expected until 2013 or later.

CO_2 Control Planning

A key to significantly reducing CO_2 emissions from electricity generation is to develop and deploy new low-and zero-emitting generation technologies. Duke Energy is pursuing the deployment and demonstration of new energy efficiency programs, renewable generation, advanced nuclear and IGCC technologies for power generation and the demonstration of carbon capture and storage (CCS) technology. Deploying these projects will contribute significantly to Duke Energy's ability to manage its climate change regulatory risk.

One of the most significant technologies for reducing/avoiding future CO_2 emissions from electricity generation is nuclear power. Today, Duke Energy operates seven nuclear units with over 7,000 megawatts of generating capacity. Duke Energy's nuclear generation program, which began with the first unit commencing operation in 1973, has been a tremendous success for the company, its customers, and its shareholders. Duke Energy has received 20-year extensions to the operating licenses for all seven units from the U.S. Nuclear Regulatory Commission (NRC), which means that this essential non-CO_2 emitting generation will be operating and helping to mitigate Duke Energy's climate change regulatory risk for many years to come. Expanding the use of nuclear power is essential for reducing future CO_2 emissions from electricity generation in the U.S. Duke Energy has submitted an application for a Construction and Operating License (COL) to the Nuclear Regulatory Commission for a new 2,234 megawatt 2-unit nuclear-powered generating facility in Cherokee County, S.C. While submitting the COL application does not commit Duke Energy to build the facility, it does keep the nuclear option available to Duke Energy as a potential significant climate change risk mitigation option. Not only is having the nuclear option available in the future critical for U.S. energy security, but also, if significant reductions in greenhouse gas emissions are mandated, new nuclear power plants must be a key part of the U.S. and Duke Energy strategy for achieving those reductions.

The continued use of coal, the most abundant domestic energy resource in the U.S., also plays a key role in Duke Energy's strategy to manage climate change regulatory risk. New low CO_2 emitting coal-based technologies must be developed and demonstrated to facilitate the continued use of coal in a carbon constrained world. Duke Energy is building a 618 MW state-of-the-art IGCC electric generating unit at its Edwardsport, Indiana site that will replace pulverized coal generating units constructed in the late 1940's and early 1950's. The new plant is currently expected to be operational in 2012. IGCC technology gasifies solid fuels, typically coal, and uses the gas to fuel high-efficiency combined-cycle turbines to generate electricity. IGCC technology holds potential for the future as it can serve as a platform for being able to cost-effectively capture CO_2 emissions from coal-fired generation. Once captured, the CO_2 can be stored underground in appropriate geologic formations instead of being released to the atmosphere. Duke Energy's Edwardsport IGCC facility is located in Indiana where Illinois Basin geology holds significant promise for being able to store a large quantity of CO_2. Duke Energy is evaluating CO_2 capture and storage at its Edwardsport IGCC facility. Duke Energy has received approval from the Indiana Utility Regulatory Commission (IURC) to conduct an engineering study for a CO_2 capture system for the Edwardsport IGCC facility, and that study is under way. Duke Energy is in the process of preparing a plan to perform site identification and characterization for geologic CO_2 sequestration for the Edwardsport facility which it will submit to the IURC for its approval to allow Duke Energy to move forward with that work. IGCC technology has the potential to become a near-zero emitting coal-based technology for generating electricity when it becomes commercially viable to pair this advanced clean coal technology with CO_2 capture and geologic storage. This would allow for the continued use of the country's vast coal reserves to help meet the country's future energy needs while significantly reducing CO_2 emissions. Therefore, development and demonstration of IGCC technology is a key part of a Duke Energy overall strategy for mitigating potential climate change regulatory risk.

Duke Energy is helping advance the demonstration of geologic CO_2 storage technology through its participation in three of the U.S. Department of Energy's (DOE) Regional Carbon Sequestration Partnerships. One is as a member of the Midwest Regional Carbon Sequestration Partnership. Through this partnership, Duke Energy is helping demonstrate the technical feasibility and cost-effectiveness of sequestering CO_2 in geologic formations in the Midwest, identify gaps and necessary regulations to support commercial deployment of the technology, and evaluate life-cycle storage options according to environmental risk, measurement, monitoring and verification protocols, public acceptance and value-added benefits. Duke Energy is hosting a geologic CO_2 storage demonstration project at its East Bend Station electric generating facility in Kentucky to help characterize the potential sequestration opportunities in the region. The demonstration project involved injecting approximately 1,000 tons of CO_2 into the Mt. Simon deep saline reservoir – considered one of the largest and highest potential saline aquifers for CO_2 storage in the United States. Duke Energy's project at East Bend Station, actually the first project to inject CO_2 into the Mt. Simon, was a great success. Once more projects have demonstrated the viability of geologic storage of CO_2, it can be added to the list of technology options available to Duke Energy to help it manage future climate change regulatory risk. When operational these facilities will reduce Duke Energy's CO_2 intensity and as a result the risks from climate change regulation. Duke Energy's 2010/2011 Sustainability Report (http://sustainabilityreport.duke-energy.com/default.asp) contains more details on our efforts to reduce our environmental footprint. It also contains the company's Sustainability Plan, which includes corporate goals to reduce CO_2 emissions from our U.S. generating fleet.

E. WATER QUALITY

1. Clean Water Act 316(b) Cooling Water Intake Structures

Federal regulations in Section 316(b) of the Clean Water Act may necessitate cooling water intake modifications for existing facilities to minimize impingement and entrainment of aquatic organisms. Both of Duke Energy Kentucky's coal-fired facilities are potential affected sources under that rule. EPA published a proposed rule in April 2011 with a final rule planned to be issued in July 2012. With an assumed timeframe for compliance of three years, implementation of selected technology is possible as early as mid-2015.

Most likely, for any facility withdrawing greater than 2 million gallons of water per day, intake screen modifications for reduction of fish impingement will be required. In addition, site specific evaluations are expected to be required to evaluate appropriate technologies to address the rule's entrainment requirements. Stations operating cooling towers, such as the East Bend station should have limited risk relative to entrainment issues.

2. Steam Electric Effluent Guidelines

In September 2009, EPA announced plans to revise the steam electric effluent guidelines. In order to assist with development of the revised regulation, EPA issued an Information Collection Request (ICR) to gather information and data from all coal-fired generating facilities. The ICR was completed by the Company and submitted to EPA in October 2010. The regulation is to be technology-based, in that limits are based on the capability of technology. The primary focus of the revised regulation is on coal-fired generation, thus the major areas likely to be impacted are Flue Gas Desulfurization (FGD) wastewater treatment systems and ash handling systems. The EPA may set limits that dictate certain FGD wastewater treatment technologies for the industry and may require the installation of dry ash handling systems for both fly and bottom ash. Following review of the ICR data, EPA plans to issue a draft rule in mid-2012 and a final rule around February 2014. After the final rulemaking, effluent guideline requirements will be included in a station's National Pollutant Discharge Elimination System (NPDES) permit renewals. Thus, requirements to comply with NPDES permit conditions may begin as early as 2017 for some facilities. The deadline to comply will depend upon each station's permit renewal schedule.

3. Waste Issues (Coal Combustion Byproducts)

Following Tennessee Valley Authority's Kingston ash dike failure in December 2008, EPA began an effort to assess the integrity of ash dikes nationwide and to begin developing a rule to manage coal combustion byproducts (CCBs). CCBs include fly ash, bottom ash and FGD byproducts (gypsum). Since the 2008 dike failure, numerous ash dike inspections have been completed by EPA and an enormous amount of input has been received by EPA as it developed proposed regulations. On June 21, 2010, EPA issued its proposed rule regarding CCBs. The EPA rule refers to these as coal combustion residuals (CCRs). The proposed rule offers two options: 1) a hazardous waste classification under Resource Conservation Recovery Act (RCRA) Subtitle C; and 2) a non-hazardous waste classification under RCRA Subtitle D, along with dam safety and alternative rules. Both options would require strict new requirements regarding the handling, disposal and potential re-use ability of CCRs. The proposal will likely result in more conversions to dry handling of ash, more landfills, closure of existing ash ponds and the addition of new wastewater treatment systems. Final regulations are not expected before 2012. EPA's regulatory classification of CCRs as hazardous or non-hazardous will be critical in developing plans for handling CCRs in the future. Compliance with new regulations is projected to begin around 2017.

F. EMISSION ALLOWANCE MANAGEMENT

The Clean Air Interstate Rule (CAIR) is currently in effect. Under CAIR, SO_2 allowances utilize the 1900 Clean Air Amendments Title IV allowance allocation, but two allowances have to be turned in for every ton of SO_2 emitted. Two separate categories of NO_x allowances are issued under CAIR. The first category is used for annual NO_x emissions and the second category is used for emissions generated during the ozone season of May through September. Duke Energy Kentucky is positioned well for 2011 CAIR SO_2 and NO_x compliance; however there could be a need to purchase or opportunity to sell, allowances based on unit operation for the remainder of the year.

Starting January 1st 2012, NO_x and SO_2 emission allowances are anticipated to come under the regulation of the Clean Air Transport Rule (CATR). Rules are still under development and are expected to be finalized by the summer of 2011. The CATR would reduce the number of NO_x and SO_2 allowance allocations from CAIR and effectively impose limits on allowance trading across state boundaries. Several allowance allocation options were provided in the proposed CATR rule and the exact allocation has not been determined. East Bend Unit 2 has a SCR for NO_x control and a FGD for SO_2 control and is generally positioned well for compliance under the range of potential allocations proposed in the CATR. Depending on the final allowance allocation, there could be a need to purchase allowances or improve control performance depending on the control efficiency of the SCR and FGD and unit operation during a particular year. Miami Fort 6 does not have advanced SO_2 or NO_x controls installed and will be challenged to meet compliance under the CATR. Options to meet compliance may include purchasing SO_2 and NO_x emissions from within the state of Ohio, switching to a lower sulfur coal, or limiting operation of the unit or some combination of these options.

For the 2011 resource plan, the CATR estimated allowance price was developed during the development of the 2011 update of the fundamental fuel and energy prices. The assumptions regarding allowance allocation, limits on trading and other specifics were based on a proposed rule and could change based on the final rule. The NO_x and SO_2 prices used for the 2011 resource plan are included in Appendix A, Table A-2.

Table 6-A - Major Environmental Regulatory Issues Schedule

*Bold Dates indicated in the Table are actual dates.

Regulation/Issue	Proposed Rule Date	Final Rule Date	Compliance Date	Notes
		Water		
316 (b)	**April 20, 2011**	July 2012	Mid-Late 2015	316(b) - regulates cooling water intake requirements
Effluent Guidelines	July 2012	February 2014	Mid-2017	
		Air		
Transport Rule (TR)	**August 2, 2010**	Mid-2011	Starting 2012	
TR Phase II	Late 2011	Late 2012	2016/2017	To incl. Ozone NAAQS
Utility MACT	**May 3, 2011**	November 2011	January 2015	
NAAQS - 8 hr. Ozone Std.	**January 6, 2010**	July 2011	Late 2017	NA Areas designated – July 2012
NAAQS PM Std.	Mid-2011	Mid-2012	Late-2018	NA Areas designated - 2014
NAAQS SO_2 Std.	**November 16, 2009**	**June 22, 2010**	Mid-2017	NA Areas designated - June 2012
		Waste		
Coal Combustion Residuals (CCRs)	**June 21, 2010**	2012	2017	
		Climate		
Greenhouse Gas Regulation – New Source Performance Standards	July 2011	May 2012	2015-2016	Tailoring Rule in effect **Jan. 2, 2011** for PSD and Title V

Table 6-B - Estimated Environmental Impact Summary (2014-2020)

		Miami Fort Unit 6	**East Bend**
Issue	Likely Impact Date	**Potential Impacts to DEK Coal Units**	
MACT Rule	2015	Hg, PM, HCL Monitoring Baghouse, additives for HAPs control	Hg, PM, HCL Monitoring Additives for Hg control (Potential for ESP upgrades or Baghouse for particulates)
NAAQS SO_2 Std.	2017	Trona Injection in conjunction with Baghouse for SO_2 control	
NAAQS Ozone Std.	2017	Selective Non Catalytic Reduction	NO_X control upgrade risk
316(b)	2015	Intake Screen Upgrades	Intake Screen Upgrades
Effluent Guidelines	2017	Dry fly ash handling conversion	
CCR Handling	2017	Pond closures, new wastewater treatment, dry ash handling conversion, new lined landfill risks.	Pond closures, new wastewater treatment, dry bottom ash conversion risks.

7. ELECTRIC TRANSMISSION FORECAST

All transmission and distribution information is located in Appendix F.

8. SELECTION AND IMPLEMENTATION OF THE PLAN

A. INTRODUCTION

Once the individual screening processes for demand-side, supply-side, and environmental compliance resources reduced the universe of options to a manageable number, the next step was to integrate the options. This chapter will describe the integration process, the sensitivity analyses, the selection of the 2011 IRP, and its general implementation.

Figure 8-1 shows Duke Energy Kentucky's Load, Capacity, and Reserves table for the years 2011 - 2031. Figure 8-2 shows the Capacity and Energy mix in 2011 and 2031

B. RESOURCE INTEGRATION PROCESS

The goal of the integration process was to take all of the pre-screened DSM, supply-side, and the environmental compliance options, and develop an integrated resource plan using a consistent method of evaluation. The tools used in this portion of the process were the Ventyx System Optimizer model and the Ventyx Planning and Risk model.

1. Model Descriptions

System Optimizer

System Optimizer is an economic optimization model that can be used to develop integrated resource plans while satisfying reliability criteria. The model assesses the economics of various resource investments including conventional units (*e.g.*, CTs, CCs, coal units, IGCCs, *etc.*), renewable resources (*e.g.*, wind, biomass), and DSM resources.

System Optimizer uses a linear programming optimization procedure to select the most economic expansion plan based on Present Value Revenue Requirements (PVRR). The model calculates the cost and reliability effects of modifying the load with demand-side management programs or adding supply-side resources to the system.

Planning and Risk

Planning and Risk is not a generation expansion model. It is principally a very detailed production costing model used to simulate the operation of the electric production facilities of an electric utility.

Some of the key inputs include generating unit data, fuel data, load data, transaction data, DSM data, emission and allowance cost data, and utility-specific system operating data. These inputs, along with its complex algorithms, make Planning and Risk a powerful tool for projecting utility electric production facility operating costs.

Engineering Screening Model

Duke Energy's in-house Engineering Environmental Compliance Planning and Screening Model (Engineering Screening Model) is a Microsoft Excel-based spreadsheet program that is used to screen environmental compliance technology options down to those that are most economic for further consideration in the System Optimizer model. The model incorporates the operating characteristics of the Duke Energy Kentucky units (net MW, heat rates, emission rates, emission control equipment removal rates, availabilities, variable O&M expenses, *etc.*), and market information (energy prices in the form of a price duration curve, emission allowance prices, fuel prices), calculates the dispatch costs of the units, and dispatches them independently against the energy price curve. The model calculates generation, emissions, operating margin, and, ultimately, free cash flow with the inclusion of capital costs.

The Engineering Screening Model also contains costs and operating characteristics of emission control equipment. This includes wet and dry flue gas desulfurization equipment (FGD or scrubber) and in-duct trona injection for SO_2 removal; selective and non-selective catalytic reduction (SCR and SNCR) and low NO_x burners (LNB) for NO_x removal; baghouses with ACI for mercury removal; and various fuel switching options with related capital costs (such as a switch to lower sulfur content coal with required electrostatic precipitator upgrades). The model also appropriately treats emission reduction co-benefits, such as increased mercury removal with the combination of SCR and FGD.

The screening operation of the Engineering Screening Model involves testing the economics of the many various combinations of emission control equipment on each unit individually by calculating the present value of the change in free cash flow (NPV) due to adding an emission control technology or fuel switch. The model ranks the alternatives by NPV. This model is considered proprietary confidential and competitive information by Duke Energy.

2. Identify and Screen Resource Options for future Consideration

Due to the relatively small size of the Duke Energy Kentucky system and the small amount of additional capacity needed over the study period, some of the generic supply-side options were modeled in blocks smaller than either the optimal economic or the commercially available sizes of these units. For example, the CT, CC, pulverized coal, IGCC, and nuclear units were limited to blocks of 35 MW in size, even though actual units utilizing these technologies are normally much larger. Using comparably sized units also creates a more level playing field for these alternatives in the model so that choices will be made based on economics rather than being unduly influenced by the sizes of units in comparison to the reserve margin requirement. This is a conservative assumption because supply-side screening typically showed that the largest unit sizes available for any given technology type were the most cost-effective, due to economies of scale. If smaller units were required for Duke Energy Kentucky, the capital costs on a $/kW basis would be much higher than the cost estimates used in this analysis. Duke Energy Kentucky could take advantage of the economies of scale from a larger unit by jointly owning such a unit with another utility or by signing a Purchased Power Agreement from such a facility.

The number of renewable technology types included in the modeling were limited in order to allow the model to reach solution more easily. Based on the results of the screening curve analysis, the renewables that were made available to the model were Biomass, Wind and Solar since these were the most prevalent of all of the renewables.

Based on the results of the screening analysis, the following technologies in Table 8-A were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs:

Table 8A Technologies Considered

Technology	Cost Basis (MW)	Modeled (MW)	% Peak Contribution
Nuclear	1,117 (2 units)	35	100%
Supercritical Coal	800	35	100%
Supercritical Coal 90% Carbon Capture	800	35	100%
IGCC	630	35	100%
Simple Cycle CT	204 (4 units)	35	100%
Combined Cycle CC	500 Unfired 150 Duct fired	28 Unfired 7 fired	100%
Wind	150	25	13%
Solar	25	2	38%
Biomass	100	2	100%

Nuclear units were considered as resource alternatives in the development of this IRP even though Kentucky currently has a moratorium on nuclear power plants until a long-term federal disposal site becomes operational. The reason for this modeling assumption is that allowing such alternatives can provide insights into what kinds of resources may be needed in the future, especially given the potential for future constraints on carbon emissions.

The DR programs were modeled as two separate "bundles" (one bundle of Non-Residential programs and one bundle of Residential programs) that could be selected based on economics. The conservation EE programs were modeled as one bundle that could be selected based on economics. The assumption was made that these costs and impacts would continue throughout the planning period.

Any generic CTs and CCs selected by the model can be viewed as "placeholders" for "peaking" and "intermediate" duty market purchases. Similarly, any generic pulverized coal, IGCC, or nuclear units selected by the model can be viewed as placeholders for base load purchases.

The integration analysis in System Optimizer was performed over a twenty year period (2011-2031). The final detailed production costing modeling in Planning and Risk was performed over the same time period, but with an additional 14 years of fixed costs and escalated production costs incorporated to better incorporate end effects.

3. Develop Theoretical Portfolio Configurations

A screening analysis using the System Optimizer model was conducted to identify the most attractive capacity options under the expected load profile as well as under a range of risk cases. This step began with a nominal set of varied inputs to test the system under different future conditions such as changes in fuel prices, load levels, and environmental requirements. These analyses yielded many different theoretical configurations of resources required to meet an annual 14.5 percent target planning reserve margin while minimizing the long-run revenue requirements to customers, with differing operating (production) and capital costs.

The nominal set of inputs included:

- Fuel costs and availability for coal, gas, and nuclear generation;
- Development, operation, and maintenance costs of both new and existing generation;
- Compliance with current and potential environmental regulations;
- Cost of capital;
- The projected load and generation resource need; and
- A menu of new generation resource options with corresponding costs and timing parameters.
- An assumed level of NOx, SO_2 based on the Clean Air Transport Rule
- Carbon

- Cap and Trade legislation with an assumed level of CO_2 prices.
- Clean Energy Standard with an Alternative Compliance Payment.

Using the insights gleaned from developing theoretical portfolios, Duke Energy Kentucky created a representative range of generation plans reflecting plant designs, lead times and environmental emissions limits. Recognizing that different generation plans expose customers to different sources and levels of risk, a variety of portfolios were developed to assess the impact of various risk factors on the costs to serve customers. The portfolios analyzed for the development of this IRP focused in the short term on the replacement option for Miami Fort 6 in 2015 and longer term the impacts of different carbon policies.

The information shown on the following pages outlines the planning options that were considered in the portfolio analysis phase. Each portfolio contains both demand response and conservation that is projected to be available and the estimated impact of a Renewable Energy Portfolio Standard (REPS).

There is not currently a Kentucky or federal REPS. However, to assess the impact to the long-term resource need, the Company believes it is prudent to plan for a renewable energy portfolio standard. In this resource plan, an assumption was made that 5% of retail sales would be met with renewable energy sources, increasing 0.5% per year starting in 2016 through 2025.

4. Conduct System Optimizer Portfolio Analysis

Portfolio options were tested under the nominal set of inputs as well as a variety of risk sensitivities and scenarios, in order to understand the strengths and weaknesses of various resource configurations and evaluate the long-term costs to customers under various potential outcomes. Four scenarios were chosen to illustrate the impacts of key risks and decisions.

- Reference Case (Cap-and-trade program): CO_2 price curve beginning in 2016 represents the potential for future federal climate change legislation. The CO_2 prices Duke Energy is utilizing fall at the lower end of the range of prices that were estimated to result from federal climate change legislation that was proposed and debated in Congress over the past few years, including H.R. 2454 – the American Clean Energy and Security Act of 2009, which passed the U.S. House of Representatives on June 26, 2009.

- Clean Energy Legislation: In addition to evaluating a potential CO_2 cap-and-trade option, the impact of potential federal Clean Energy legislation without a separate price on CO_2 emissions was also evaluated. Assumptions used in this analysis include:
  - 10% of retail sales in 2015 must be supplied by clean energy resources, increasing 1% per year to 30% by 2030.
  - Resource Options that qualify as clean energy include renewable resources, energy efficiency (can be used to meet up to 25% of the requirement), new nuclear generation, coal generation, with carbon capture and sequestration, and 50 percent credit for new combined cycle natural gas generation.
  - An alternative compliance payment set at $50/MWh is available as a compliance option.

The four portfolios that were analyzed are shown below:

1. Reference Case: Cap & Trade - Combined Cycle portfolio (RC - CC)
2. Reference Case: Cap & Trade - Combustion Turbine portfolio (RC - CT)
3. Clean Energy Standard – Combined Cycle Portfolio (CES – CC)
4. Clean Energy Standard – Nuclear and Combine Cycle Portfolio (CES – Nuclear)

An overview of the specifics of each portfolio is shown in Table 8B below.

The sensitivities chosen to be performed for these scenarios were those representing the highest risks going forward. The following sensitivities were evaluated in the Reference Case scenarios and sensitivities on load and fuel price were evaluated for the Clean Energy Standard:

- Load forecast variations
  - Increase relative to base forecast (+10% for peak demand and energy by 2030)
  - Decrease relative to base forecast (- 10% for peak demand and energy by 2030)
- Fuel price variability
  - Higher Fuel Prices (coal prices 25% higher, natural gas prices 20% higher)
  - Lower Fuel Prices (coal prices 40% lower, natural gas prices 40% lower)

- Emission allowance price variability
  - Higher CO_2 Prices – Based on projected impact of Waxman/Markey legislation
  - A no CO_2 allowance price sensitivity was evaluated to determine any impacts on the expansion plan.

- Energy Efficiency
  - The High Energy Efficiency sensitivity includes increasing impacts until the load impacts reach the economic potential identified by the 2009 market potential study. When fully implemented, this increased energy efficiency resulted in approximately an 8% decrease in retail sales, in addition to the base energy efficiency assumption through the study period.
  - A no Energy Efficiency sensitivity was evaluated to determine if the Base EE and High EE are cost effective.
- Renewables
  - A no renewables case was performed to determine the impact on the expansion plan and determine the cost of implementing the program.
  - A high solar sensitivity was evaluated to estimate the impact of distributive generation. In this case the amount of solar was increase from 0.25% to 1.0% when fully implemented.
- Purchases and Sales – The base assumption was to allowance purchases and no sales to develop the base portfolios. This allows the development of a portfolio that is optimized to meet customers' needs which taking advantage of market purchases, but is not optimized for speculative market sales. However, sensitivities were made allowing sales in some cases to determine and change to the portfolios.

Table 8-B – Portfolios Evaluated

Year	Portfolio			
	RC - CT	RC - CC	CES CC	CES Nuclear
2012				
2013				
2014				
2015	140 MW (CT)	140 MW (CC)	140 MW (CC)	140 MW (CC)
2016			35 MW (CC)	35 MW (CC)
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027	35 MW (CT)	35 MW (CC)		
2028			35 MW (CC)	35 MW (N)
2029				
2030				
2031	35 MW (CT)	35 MW (CC)		
Total CT	210 MW			
Total CC		210 MW	210 MW	175 MW
Total Nuclear				35 MW
Total Retire	163 MW	163 MW	163 MW	163 MW

Several insights of review of the System Optimizer sensitivity analysis include:

- Demand Response and Energy Efficiency – A comparison of the PVRR of the no EE sensitivity to the base and high EE cases was made to determine if these programs were cost effective. Both the base EE and high EE cases resulted in lower PVRRs than the no DSM case which demonstrates these programs to be cost effective assuming the level of impacts can be achieved with the cost estimates.
- No Renewables – If a RPS is not included in the resource plan, this accelerates the long term resource need in 2027 to 2022. The revenue requirement associated

with the renewable portfolio was $87 Million (PVRR) higher than the no renewable portfolio.

- Higher Solar implementation – To simulate the potential impact on the long term resource plan of increased distributive generation, the amount of solar was increased from 0.25% to 1% of retail sales. The inclusion of an increased solar requirement delayed the long term capacity need from 2027 to 2028, and advantages CT generation over CC generation in that timeframe.
- High and Low Load, High Fuel Cost – The impact of these three sensitivities did not impact the resource selection of CC generation in 2015. However, in the 2023 to 2031 timeframe for the High load sensitivity CT generation was selected in lieu of CC generation.
- Low Fuel Cost – In the low fuel cost sensitivity CT generation was selected in lieu of CC generation in 2015. This was driven primarily due to the lower energy prices where it was less expensive to purchase from the market than operation of CC generation and energy sales were not included.
- High CO_2 and no CO_2 - The impact of the high CO_2 sensitivity did not impact the resource selection of CC generation. In the no CO_2 sensitivity new coal generation was selected in lieu of CC. It would be very difficult to permit new coal fired generation at this time. However, this is an indication that new coal generation is competitive with CC generation with lower carbon prices.
- Market Sales – Several sensitivities were performed allowing energy sales in addition to purchases in the portfolio development. None of the sensitivities allowing sales impacted the selection of CC generation in 2015. However, in the high fuel sensitivity with sales included, a 35 MW block of nuclear was selected in 2030. In the high fuel sensitivity of limiting purchases but allowing sales, new coal generation was selected in 2017, but was not needed from a reserve margin perspective.

5. Quantitative Analysis Results

a. Evaluation of Retirement Decision at Miami Fort 6

The purpose of this analysis was to evaluate the cost effectiveness of controls on Miami Fort 6 to meet anticipated environmental regulatory requirements versus retirement and replacement of this generation with CC generation. During the system optimizer evaluation, in all but one sensitivity the optimal resource replacement for Miami Fort 6 was 140 MW of CC generation in 2015. Using the results of the Engineering Screening Model the anticipated control requirements to meet future environmental regulations are listed below.

- Fabric Filter (Baghouse) – Used for Air Toxic and SO_2 Control
- Activated Carbon Injection – Used in conjunction with the fabric filter for Mercury control
- Selective Non Catalytic Reduction – Used for NOx reduction
- Trona Injection – Used in conjunction with the fabric filter for SO_2 control
- Continuous Emission Monitors – Used for measurement of mercury and other air toxics
- Dry Flyash and Bottom Ash Conversion – Required for placement of in a lined landfill versus an ash basin.
- Lined Landfill – Required in lieu of an ash basin for ash disposal.
- Wastewater treatment – Used for treatment of the station wastewater treatment in lieu of existing ash basin.
- Intake Screens and Modifications – Used for control on fish impingement and entrainment on the water intakes.

The capital cost and increased fixed and variable O&M associated with these controls were incorporated into the analysis. It is also anticipated to meet the requirements of the SO_2 Control requirements associated with the Clean Air Transport Rule and lower SO_2 National Ambient Air Quality Standard that Miami Fort 6 would have to switch to a lower sulfur fuel with this equipment set.

The equipment selection above was an estimate of the minimum control requirements to meet the environmental regulatory requirements. Longer term there is a risk of more advanced control like Flue Gas Desulfurization for SO_2 control and Selective Catalytic Reduction for NOx control which would increase the capital cost substantially.

Three portfolios were developed to evaluate the cost effectiveness of installation of controls versus retirement of the unit and replacement with 140 MW CC.

- Base Case – Retire Miami Fort 6 in 2015 and replace with a 140 MW CC.
- 2025 Control Case – Installation of environmental controls described above but retire by 2025 and replace with a 140 MW CC due to increased environmental regulatory requirements.
- 2035 Control Case – Installation of environmental controls described above with 20 years of continued operation to 2035.

Each case was evaluated with the detailed production cost model PAR and the PVRR was calculated incorporating the production and capital cost. Table 8-C below represents a comparison of the PVRRs for each case.

Table 8-C PVRR Comparisons

Portfolio	PVRR (Million $$)	Delta (Million $$)
Base Case	$4,673.0	
2025 Control Case	$4,789.1	$115.8
2035 Control Case	$4,789.0	$115.7

The Base Case was the lowest cost option to customers versus installation of controls. There is a significant risk that additional environmental controls could be required as future environmental regulatory requirements emerge in the future.

b. Detailed Portfolio Analysis

The focus of the detail portfolio analysis was to determine optimum resource selection in 2015 when Miami Fort 6 is retired and to identify the type and timing of future generation in the longer term under a Cap and Trade and a Clean Energy Standard construct. The potential resource planning strategies were tested under base assumptions and variations in fuel and energy cost, load, energy efficiency, and renewables.

For the base case and each sensitivity, the PVRR was calculated for each portfolio. The revenue requirement calculation estimates the cost to customers for the Company to recover system production cost and new capital incurred. A 34-year analysis time frame was used to fully capture the long-term impact of the technology selected to replace Miami Fort 6 in 2015. Table 8-D below represents a comparison of the Reference Case Combined Cycle portfolio (RC-CC) and the Reference Case Combustion Turbine portfolio (RC-CT) under the Cap and Trade regulatory construct and the Clean Energy Standard Combined Cycle portfolio (CES-CC) to the Clean Energy Standard Nuclear portfolio (CES-Nuclear) under the Clean Energy Standard regulatory construct. The green block represents the lowest PVRR between the two options and value contained with the block is the PVRR savings between the two cases.

Table 8-D
Comparison of Portfolios
(Cost are represented in $millions)

Cap and Trade Construct

	Reference Case	Renewables	Fuel Sensitivity		Load Sensitivities		
Portfolio		No Renewables	High Fuel Cost	Low Fuel Cost	High Load	Low Load	High EE
CT							
CC	$247	$141	$204	$118	$275	$97	$356

Clean Energy Plan Construct

	Reference Case	Fuel Sensitivity	
Portfolio		High Fuel Cost	Low Fuel Cost
CC (2027)			
Nuclear (2027)	$50	$73	$32

In the Cap and Trade regulatory construct, the reference case and each sensitivity, the combined cycle portfolio was preferred over meeting the need with additional CT generation. In this analysis, energy sales were allowed which benefited the CC portfolio. The CT portfolio relied on increased purchases from the energy market to meet the energy needs and had limited sales opportunities. The first capacity need after 2015 is not until 2027 if the DSM and REPS programs are implemented. If there is no requirement for renewables this would accelerate the 35 MW capacity need to 2022.

In the Clean Energy Standard regulatory construct, adding an increment of nuclear generation in the 2028 to 2031 timeframe was preferred in the reference case, if fuel prices are higher. If fuel prices are lower, combined cycle generation was preferred over nuclear over the same timeframe. Both the DSM program and the addition of renewables were cost effective parts of meeting the clean energy requirement.

In summary, combined cycle generation was the optimal resource selection to replace Miami Fort 6 in 2015. Though CC generation was selected as the optimal replacement, new coal generation was competitive as a replacement option under the Cap and Trade regulatory construct. However, combined cycle generation has an advantage over coal in a Clean Energy Standard construct because half of its generation would count toward the compliance. Duke Energy Kentucky is evaluating options to satisfy the 2015 capacity need.

Longer term the first capacity need is not until 2027 and there will be time to optimize the plan as future regulations develop. However, continuation of DSM programs was shown to be cost effective as compared to conventional generation resources. If the DSM programs are not pursued this would increase the capacity need in 2015 by 47 MW to 175 MW total and accelerate the future 35MW need to 2020.

Figure 8-1 represents the Load, Capacity, and Reserves table for the chosen plan.

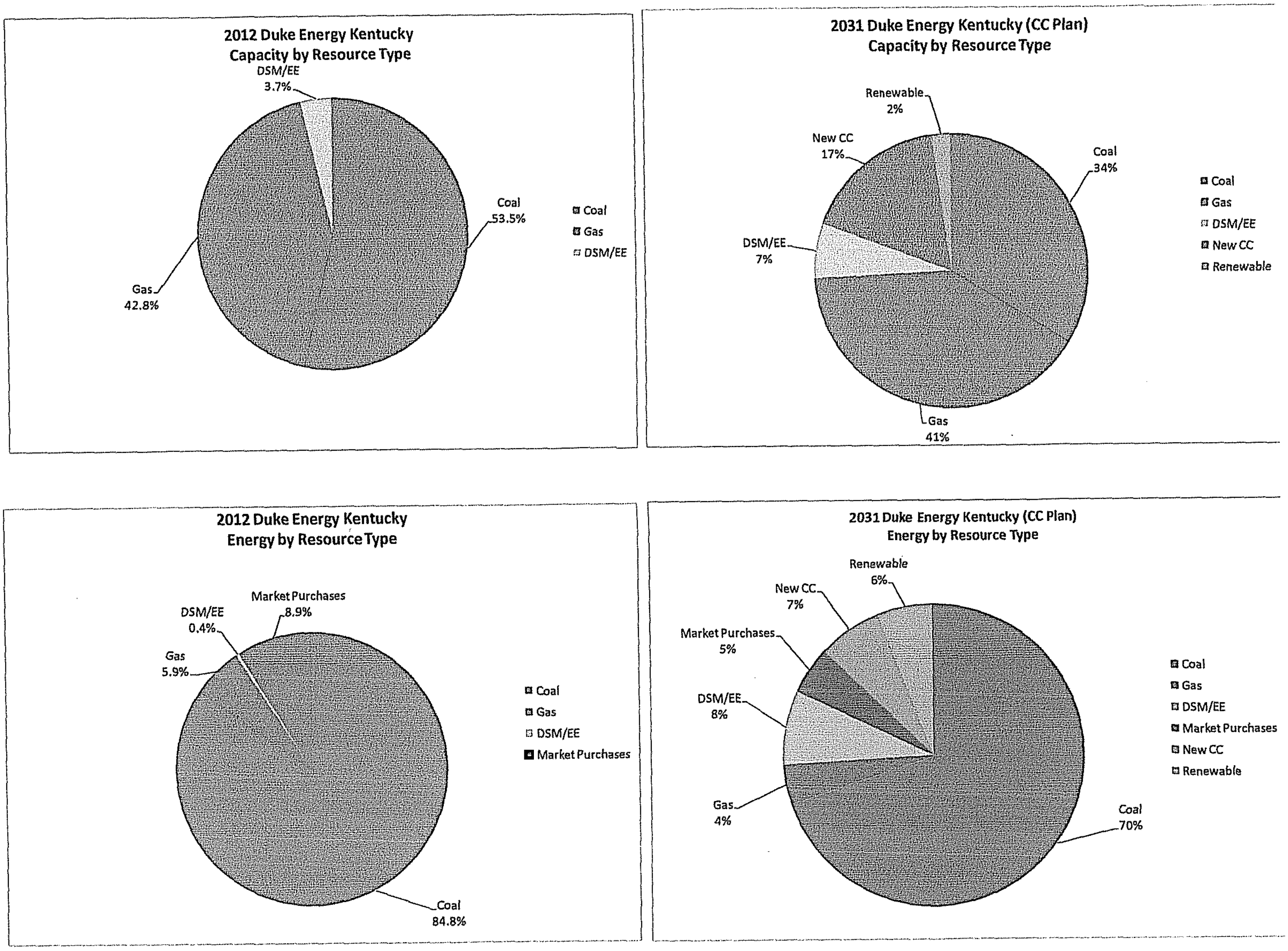
Figure 8-1 Load, Capacity and Reserves Table

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Kentucky 2011 IRP

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Load Forecast																					
1 Duke System Peak	886	900	913	930	940	941	949	956	963	971	979	987	995	1,001	1,007	1,014	1,023	1,032	1,041	1,050	1,061
Reductions to Load Forecast																					
2 New EE Programs	(0)	(2)	(4)	(6)	(8)	(11)	(13)	(15)	(17)	(19)	(21)	(23)	(25)	(27)	(30)	(31)	(33)	(35)	(38)	(40)	(40)
3 Demand-Side Management																					
Power Share (DR/BTMG)	(26)	(26)	(23)	(25)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)
Power Manager (DLC)	(11)	(12)	(12)	(12)	(12)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)
4 Adjusted Duke System Peak	**849**	**860**	**875**	**887**	**893**	**891**	**897**	**901**	**906**	**912**	**918**	**924**	**930**	**933**	**937**	**943**	**949**	**957**	**963**	**970**	**981**
Cumulative System Capacity																					
4 Generating Capacity	1,039	1,039	1,039	1,039	1,039	914	914	914	914	914	914	914	914	914	914	914	914	914	914	914	914
5 Capacity Additions	0	0	0	0	38	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	0	0	0	0	(163)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	1,039	1,039	1,039	1,039	914	914	914	914	914	914	914	914	914	914	914	914	914	914	914	914	914
Purchase Contracts																					
9 Cumulative Purchase Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 Behind the Meter Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Cumulative Future Resource Additions																					
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peaking/Intermediate	0	0	0	0	140	140	140	140	140	140	140	140	140	140	140	140	175	175	175	175	210
Renewables	0	0	0	0	0	5	8	11	11	14	19	20	22	24	26	26	26	26	26	26	26
13 Cumulative Production Capacity	**1,039**	**1,039**	**1,039**	**1,039**	**1,054**	**1,059**	**1,062**	**1,065**	**1,065**	**1,068**	**1,073**	**1,074**	**1,076**	**1,078**	**1,080**	**1,080**	**1,115**	**1,115**	**1,115**	**1,115**	**1,150**
Reserves																					
14 Generating Reserves	190	179	164	152	161	168	165	164	159	156	154	150	146	145	143	137	166	159	152	145	169
15 % Reserve Margin	**22.4%**	**20.8%**	**18.8%**	**17.1%**	**18.0%**	**18.9%**	**18.4%**	**18.2%**	**17.6%**	**17.1%**	**16.8%**	**16.2%**	**15.7%**	**15.5%**	**15.2%**	**14.5%**	**17.5%**	**16.6%**	**15.8%**	**15.0%**	**17.3%**
16 % Capacity Margin	18.3%	17.2%	15.8%	14.6%	15.3%	15.9%	15.6%	15.4%	14.9%	14.6%	14.4%	14.0%	13.6%	13.4%	13.2%	12.7%	14.9%	14.2%	13.7%	13.0%	14.7%

The figures below represent the changes in the capacity mix and energy mix between 2012 and 2031. The relative shares of renewables, energy efficiency, and gas all increase, while the relative share of coal decreases.

Figure 8-2 Generation Mix 2012 and 2031



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Appendix A – Supply Side Screening Curves/ Allowance Prices

APPENDIX A – SUPPLY SIDE SCREENING CURVES/ALLOWANCE PRICES

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Supply-Side Screening Curves

The following pages contain the screening curves and associated data discussed in Chapter 5 of this filing.

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Figure A-1 Baseload Technologies Screening

[redacted]

Figure A-2 Peak/Intermediate Screening

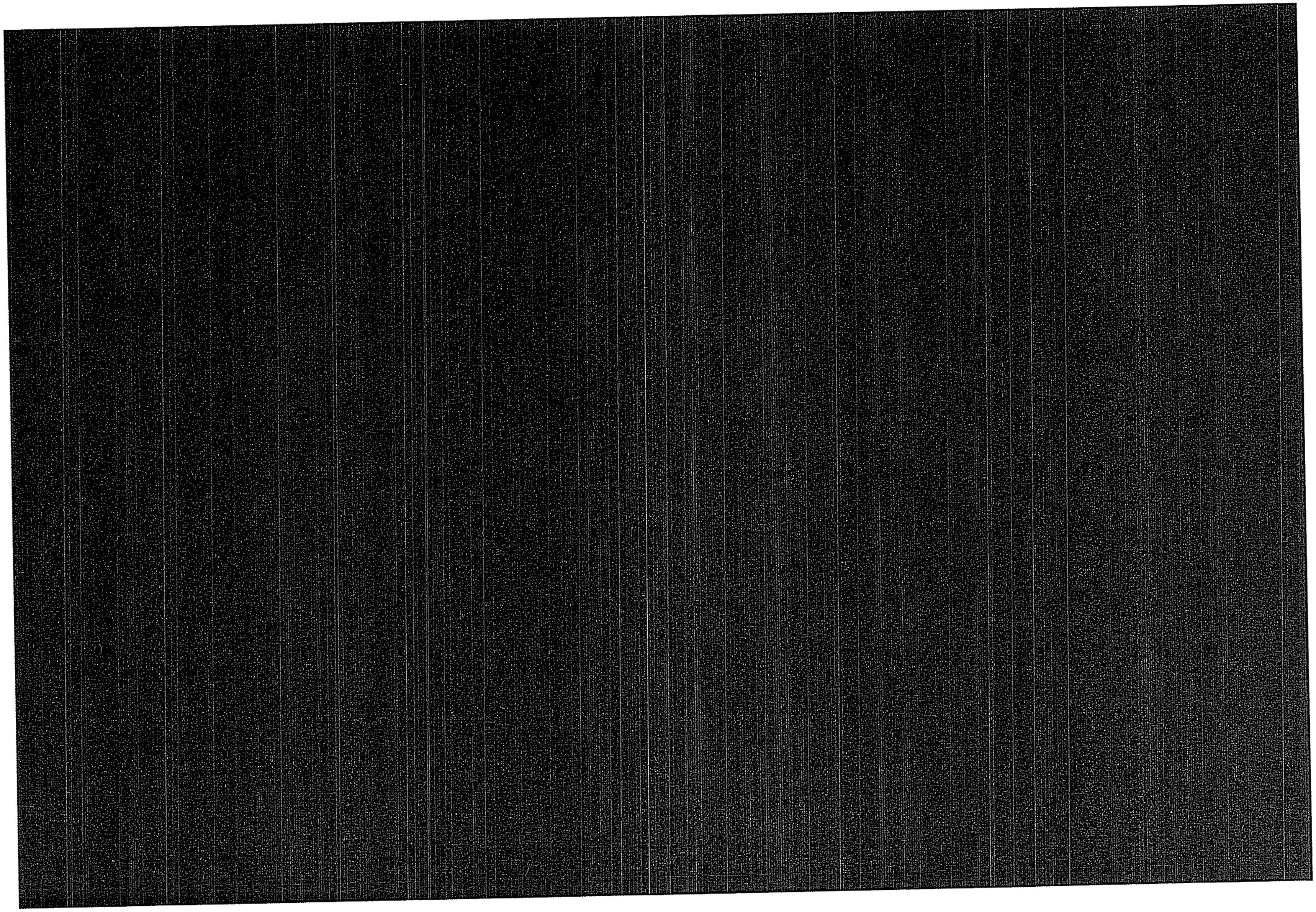

Figure A-3 Renewable Technologies Screening

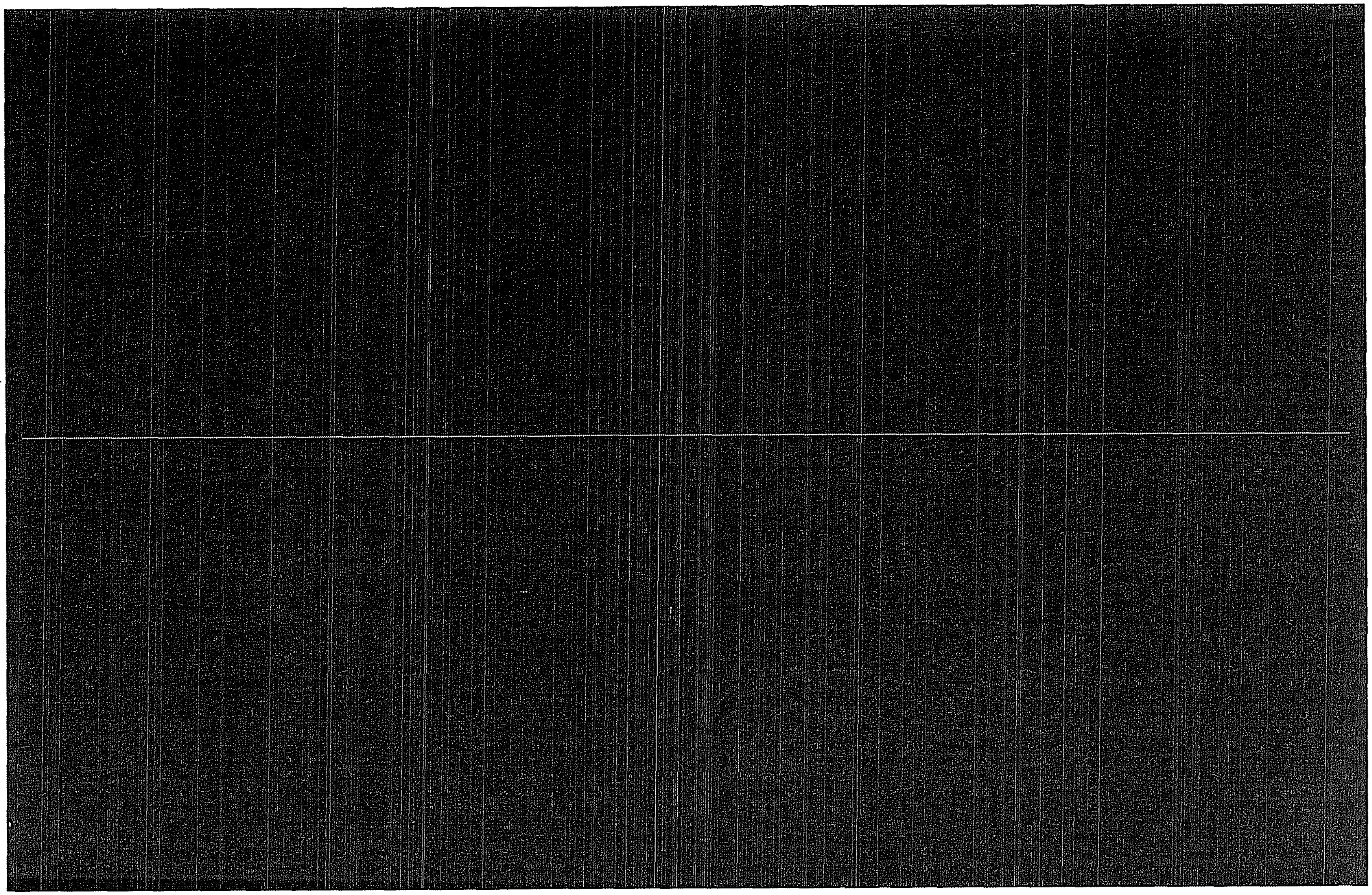

Table A-1 Supply Side Technology Information 2011-2018

[redacted]

Allowance Price Forecasts

The following tables contain the allowance price forecasts used in the development of this IRP. These forecasts are trade secrets and are proprietary to Duke Energy Kentucky. The redacted information will be made available to appropriate parties upon execution of appropriate confidentiality agreements or protective orders.

Table A-2 Annual Allowance Price Forecast

[redacted]

Existing Assets

The following tables contain information on the existing generating assets providing generation to Duke Energy Kentucky customers. The following tables contain pertinent information about each asset, Maximum Net Dependable Capacity (MNDC) information on jointly owned units, and fuel storage capability at these facilities.

Table A-3

DUKE ENERGY KENTUCKY

SUMMARY OF EXISTING ELECTRIC GENERATING FACILITIES

STATION NAME & LOCATION	FOOT NOTES	UNIT	TYPE OF UNIT*	INSTALLATION DATE MONTH & YEAR	TENTATIVE RETIREMENT YEAR	MAXIMUM GENERATING CAPABILITY (net kW) SUMMER	WINTER	ENVIRONMENTAL PROTECTION MEASURES*	MAXIMUM GENERATING CAPABILITY (net kW) Spring/Fall
East Bend Boone County Kentucky	A	2	CF-S	3-1981	Unknown	414,000	414,000	EP, LNB, CT, SO_2 Scrubber, SCR, & TRO	414,000
Miami Fort North Bend, Ohio		6	CF-S	11-1960	Unknown	163,000	163,000	EP, LNB, & OFA	163,000
Woodsdale Trenton, Ohio	B	1	GF/PF-GT	5-1993	Unknown	83,433	94,000	WI	86,000
	B	2	GF/PF-GT	7-1992	Unknown	83,433	94,000	WI	86,000
	B	3	GF/PF-GT	5-1992	Unknown	83,433	94,000	WI	86,000
	B	4	GF/PF-GT	7-1992	Unknown	83,433	94,000	WI	86,000
	B	5	GF/PF-GT	5-1992	Unknown	83,433	94,000	WI	86,000
	B	6	GF/PF-GT	5-1992	Unknown	83,433	94,000	WI	86,000
					Station Total:	500,598	564,000		516,000
				SYSTEM TOTAL:		1,077,598	1,141,000		1,093,000

*LEGEND:

CF = Coal Fired
GF = Natural Gas Fired
PF = Propane Fired

S = Steam
GT = Simple-Cycle Combustion Turbine

EP = Electrostatic Precipitator
CT = Cooling Towers
WI = Water Injection, NOx
LNB = Low NOx Burners
OFA = Overfire Air
SCR = Selective Catalytic Reduction
TRO = Trona Injection System

FOOTNOTES:

(A) Unit 2 is commonly owned by Duke Energy Kentucky (69% - Operator) and The Dayton Power and Light Company (31%). Earlier vintage LNB installed.

(B) Unit Ratings are at Ambient Temperature Conditions of: Summer - 90 degF; Winter - 20 degF and include inlet misting capability

Table A-4

Maximum Net Demonstrated Capaility of Jointly Owned Generating Units

Station Name and Location	Unit Number	Installation Date	Total MW		DEK Share		DP&L Share	
			Summer	Winter	Summer	Winter	Summer	Winter
East Bend Boone County, KY	2	3-1981	600	600	414	414	186	186

NOTE: Totals may not add due to rounding to whole numbers.

Table A-5

APPROXIMATE FUEL STORAGE CAPACITY

Generating Station	Coal Capacity (Tons)	Oil Capacity (Gallons)	Propane Capacity (Barrels)
East Bend	500,000	500,000	--
Miami Fort	350,000	4,300,000	--
Woodsdale	--	--	48,000

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Appendix B – Electric Load Forecast

APPENDIX B – ELECTRIC LOAD FORECAST
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B. ELECTRIC LOAD FORECAST

1. GENERAL

Duke Energy Kentucky provides electric and gas service in the Northern Kentucky area. Duke Energy Kentucky serves approximately 136,000 customers in its approximate 300 square mile service territory. Duke Energy Kentucky's service territory includes the cities of Covington and Newport, Kentucky.

Duke Energy Kentucky owns an electric transmission system and an electric distribution system in Kenton, Campbell, Boone, Grant, and Pendleton counties of Northern Kentucky. Duke Energy Kentucky also owns a gas distribution system, which serves either all or parts of Kenton, Campbell, Boone, Grant, Gallatin, and Pendleton counties in Northern Kentucky.

The electric energy and peak demand forecasts of the Duke Energy Kentucky service territory are prepared each year as part of the planning process by a staff that is shared with the other Duke Energy affiliated utilities, using the same methodology. Duke Energy Kentucky does not perform joint load forecasts with non-affiliated utility companies, and the forecast is prepared independently of the forecasting efforts of non-affiliated utilities.

2. FORECAST METHODOLOGY

The forecast methodology is essentially the same as that presented in past Integrated Resource Plans filed with the Commission.

Energy is a key commodity linked to the overall level of economic activity. As residential, commercial, and industrial economic activity increases or decreases, the use of energy, or more specifically electricity, should increase or decrease, respectively. It is this linkage to economic activity that is important to the development of long-range energy forecasts. For that reason, forecasts of the national and local economies are key ingredients to energy forecasts.

The general framework of the Electric Energy and Peak Load Forecast involves a national economic forecast, a service area economic forecast, and the electric load forecast.

The national economic forecast provides information about the prospective growth of the national economy. This involves projections of national economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, and income. The national economic forecast is obtained from Moody's Analytics, a nationally recognized vendor of economic forecasts. In conjunction with the forecast of the national economy, the Company also obtains a forecast of the service area economy from Moody's Analytics. The Duke Energy Kentucky service area is located in Northern Kentucky adjacent to the service area of DE-Ohio. The economy of Northern Kentucky is contained within the Cincinnati Primary Metropolitan Statistical Area ("PMSA") and is an integral part of the regional economy.

The service area economic forecast is used along with the energy and peak models to produce the electric load forecast.

a. Service Area Economy

There are sectors to the service area economy: employment, income, inflation, production, and population. Forecasts of employment are provided by North American Industry Classification System (NAICS) and aggregated to major sectors such as commercial and industrial. Income for the local economy is forecasted in several categories including wages, rents, proprietors' income, personal contributions for social insurance, and transfer payments. The forecasts of these items are summed to produce the forecast of income less personal contributions for social insurance. Inflation is measured by changes in the Consumer Price Index (CPI). Production is projected for each key NAICS group by multiplying the forecast of productivity (production per employee) by the forecast of employment. Population projections are aggregated from forecasts by age-cohort. This information serves as input into the energy and peak load forecast models.

b. Electric Energy Forecast

The forecast methodology follows economic theory in that the use of energy is dependent upon key economic factors such as income, production, energy prices, and the weather. The projected energy requirements for Duke Energy Kentucky's retail electric customers are determined through econometric analysis. Econometric models are a means of representing economic behavior through the use of statistical methods, such as regression analysis.

The Duke Energy Kentucky forecast of energy requirements is included within the overall forecast of energy requirements of the Greater Cincinnati and Northern Kentucky region. The Duke Energy Kentucky sales forecast is developed by allocating percentages of the total regional forecast for each customer group. These groups include residential, commercial, industrial, governmental or other public authority, and street lighting energy sectors. In addition, forecasts are also prepared for three minor categories: interdepartmental use (Gas Department), Company use, and losses. In a similar fashion, the Duke Energy Kentucky peak load forecast is developed by allocating a share from the regional total. Historical percentages and judgment are used to develop the allocations of sales and peak demands.

The following sections provide the specifications of the econometric equations developed to forecast electricity sales for Duke Energy Kentucky's service territory.

<u>Residential Sector</u> - There are two components to the residential sector energy forecast: the number of residential customers and kWh energy usage per customer. The forecast of total residential sales is developed by multiplying the forecasts of the two components. That is:

(1) Residential Sales =

Number of Residential Customers * Use per Residential Customer.

Econometric relationships are developed for each of the component pieces of total residential sales.

<u>Customers</u> - The number of electric residential customers (households) is affected by real per capita income. This is represented as follows:

(2) Residential Customers =

f (Real Per Capita Income)

Where: Real Per Capita Income = (Personal Income/Population/CPI).

While changes in population and per capita income are expected to alter the number of residential customers, the adjustment relating to real per capita income is not immediate. The number of customers will change gradually over time as a result of a change in real per capita income. This adjustment process is modeled using a lag structure.

<u>Residential Use per Customer</u> - The key ingredients that impact energy use per customer are per capita income, real electricity prices and the combined impact of numerous other determinants. These include the saturation of air conditioners, electric space heating, other appliances, the efficiency of those appliances, and weather.

(3) Energy usage per Customer =

f (Real Income per Capita * Efficient Appliance Stock,
Real Electricity Price * Efficient Appliance Stock,
Saturation of Electric Heating Customers,
Saturation of Customers with Central Air Conditioning,
Saturation of Window Air Conditioning Units,
Efficiency of Space Conditioning Appliances,

Billed Cooling and Heating Degree Days).

The derivation of the efficient appliance stock variable and the forecast of appliance saturations are discussed in the data section.

Commercial Sector - Commercial electricity usage changes with the level of local commercial employment, real electricity price, and the impact of weather. The model is formulated as follows:

(4) Commercial Sales =

f (Commercial Employment,

Marginal Electric Price/Consumer Price Index,

Billed Cooling and Heating Degree Days).

Industrial Sector - Duke Energy Kentucky produces industrial sales forecasts by NAICS classifications. Electricity use by industrial customers is primarily dependent upon the level of industrial production and the impacts of real electricity prices, electric price relative to alternate fuels, and weather. The general model of industrial sales is formulated as follows:

(5) Industrial Sales =

f (Industrial Production,

Real Electricity Price,

Electricity Price/Alternate Fuel Price,

Billed Cooling and Heating Degree Days).

Governmental Sector - The Company uses the term Other Public Authorities (OPA) to indicate those customers involved and/or affiliated with federal, state or local government. Two categories comprise the electricity sales in the OPA sector: sales to OPA water pumping customers and sales to OPA non-water pumping customers.

In the case of OPA water pumping, electricity sales are related to the number of residential electricity customers, real price of electricity demand, precipitation levels, and heating and cooling degree days. That is:

(6) Water Pumping Sales =

f (Residential Electricity Customers,
Real Electricity Demand Price,
Precipitation,
Cooling Degree Days).

Electricity sales to the non-water pumping component of OPA is related to governmental employment, the real price of electricity, the real price of natural gas, and heating and cooling degree days. This relationship can be represented as follows:

(7) Non-Water Pumping Sales =

f (Governmental Employment,
Marginal Electric Energy Price/Natural Gas Price,
Billed Cooling and Heating Degree Days).

The total OPA electricity sales forecast is the sum of the individual forecasts of sales to water pumping and non-water pumping customers.

Street Lighting Sector - For the street lighting sector, electricity usage varies with the number of street lights and the efficiency of the lighting fixtures used. The number of street lights is associated with the population of the service area. The efficiency of the street lights is related to the saturation of mercury and sodium vapor lights. That is:

(8) Street Lighting Sales =

f (Population,
Saturation of Mercury Vapor Lights,
Saturation of Sodium Vapor Lights).

Total Electric Sales - Once these separate components have been projected - Residential sales, Commercial sales, Industrial sales, OPA sales, and Street Lighting sales - they can be summed along with Interdepartmental sales to produce the projection of total electric sales.

Total System Sendout - Upon completion of the total electric sales forecast, the forecast of total system sendout (net energy) can be prepared. This requires that the total electric sales forecast be combined with the forecasts of Company use and system losses. After the system sendout forecast is completed, the peak load forecast can be prepared.

Peak Load - Forecasts of summer and winter peak demands are developed using econometric models.

The peak forecasting model is designed to closely represent the relationship of weather to peak loads. Only days when the temperature equaled or exceeded 90 degrees are included in the summer peak model. For the winter, only those days with a temperature at or below 10 degrees are included in the winter peak model.

Summer Peak - Summer peak loads are influenced by the current level of economic activity and the weather conditions. The primary weather factors are temperature and humidity; however, not only are the temperature and humidity at the time of the peak important, but also the morning low temperature, and high temperature from the day before. These other temperature variables are important to capture effect of thermal buildup.

The summer equation can be specified as follows:

(9) Peak =

f (Weather Normalized Sendout,

Weather Factors).

Winter Peak - Winter peak loads are also influenced by the current level of economic activity and the weather conditions. The selection of winter weather factors depends upon whether the peak occurs in the morning or evening. For a morning peak, the primary weather factors are morning low temperature, wind speed, and the prior evening's low temperature. For an evening peak, the primary weather factors are the evening low temperature, wind speed, and the morning low temperature.

The winter equation is specified in a similar fashion as the summer:

(10) Peak =

f (Weather Normalized Sendout,

Weather Factors).

The summer and winter peak equations are estimated separately for the respective seasonal periods. Peak load forecasts are produced under specific assumptions regarding the type of weather conditions typically expected to cause a peak.

Weather-Normalized Sendout - The level of peak demand is related to economic activity. The best indicator of the combined influences of economic variables on peak demand is the level of base load demand exclusive of aberrations caused by non-normal weather. Thus, the first step in developing the peak equations is to weather normalize historical monthly sendout.

The procedure used to develop historical weather-normalized sendout data involves two steps. First, instead of weather normalizing sendout in the aggregate, each component is weather normalized. In other words, residential, commercial, industrial, and other public authority, are individually adjusted for the difference between actual and normal weather. Street lighting sales are not weather normalized because they are not weather sensitive. Using the equations previously discussed, the adjustment process is performed as follows:

Let: KWH(N) = f(W(N))g(E)

KWH(A) = f(W(A))g(E)

Where: KWH(N) = electric sales - normalized

W(N) = weather variables - normal

E = economic variables

KWH(A) = electric sales - actual

W(A) = weather variables - actual

Then: KWH(N) = KWH(A) * f(W(N))g(E)/f(W(A))g(E)

=KWH(A) * f(W(N))/f(W(A))

With this process, weather-normalized sales are computed by scaling actual sales for each class by a factor from the forecast equation that accounts for the impact of deviation from normal weather. Industrial sales are weather normalized using a factor from an aggregate industrial equation developed for that purpose.

Second, weather-normalized sendout is computed by summing the weather-normalized sales with non-weather sensitive sector sales. This weather-adjusted sendout is then used as a variable in the summer and winter peak equations.

Peak Forecast Procedure - The summer peak usually occurs in August in the afternoon and the winter peak occurs in January in the morning. Since the energy model produces forecasts under the assumption of normal weather, the forecast of sendout is "weather normalized" by design. Thus, the forecast of sendout drives the forecast of the peaks. In the forecast, the weather variables are set to values determined to be normal peak-producing conditions. These values are derived using historical data on the worst weather conditions in each year (summer and winter).

3. ASSUMPTIONS

a. Macroeconomic

It is generally assumed that the Duke Energy Kentucky service territory economy will tend to react much like the national economy over the forecast period. Duke Energy Kentucky uses a long-term forecast of the national and service area economy prepared by Moody's Analytics.

No major wars or energy embargoes are assumed to occur during the forecast period. Even if minor conflicts and/or energy supply disruptions, such as those caused by hurricanes, occur during the forecast period, the long-range path of the overall forecast would not be dramatically altered.

A major risk to the national and regional economic forecasts and hence the electric load forecast is the continued economic growth in the U.S. economy. While the national and local economies have been experiencing the effects of a decline in economic activity since the fourth quarter of 2007, there are strong signs that the economy is recovering. The ultimate outcome in the near term is dependent upon the success of the economy moving forward out of this slow period as well as managing recent increases in energy prices.

With extensive economic diversity, the Cincinnati area economy, including Northern Kentucky, is well structured to withstand an economic slowdown and make the adjustments necessary for growth. In the manufacturing sector, its major industries are food products, paper, printing, chemicals, steel, fabricated metals, machinery, and automotive and aircraft transportation equipment. In the non-manufacturing sector, its major industries are life insurance and finance. In addition, the Cincinnati area is the headquarters for major international and national market-oriented retailing establishments.

In late 2007, President Bush signed the Energy Independence and Security Act (EISA), part of which sets new efficiency standards for lighting staring in 2012. This forecast incorporates impacts associated with EISA.

b. Local

Forecasts of employment, local population, industrial production, and inflation are key indicators of economic and demographic trends for the Duke Energy Kentucky service area. The majority of the employment growth over the forecast period occurs in the non-manufacturing sector. This reflects a continuation of the trend toward the service industries and the fundamental change that is occurring in manufacturing and other basic industries. The rate of growth in local employment expected over the forecast will be slightly above that of the nation: 0.7 percent locally versus 1.3 percent nationally.

Duke Energy Kentucky is also affected by national population trends. The average age of the U.S. population is rising. The primary reasons for this phenomenon are stagnant birth rates and lengthening life expectancies. As a result, the portion of the population of the Duke Energy Kentucky service area that is "age 65 and older" increases over the forecast period. Over the period 2008 to 2028, Duke Energy Kentucky's population is expected to increase at an annual average rate of 0.6 percent. Nationally, population is expected to grow at an annual rate of 1.0 percent over the same period.

For the forecast period, local industrial production is expected to increase at a 2.0 percent annual rate, while 1.4 percent is the expected growth rate for the nation.

The residential sector is the largest in terms of total existing customers and total new customers per year. Within the Duke Energy Kentucky service area, many commercial customers serve local markets. Therefore, there is a close relationship between the growth in local residential customers and the growth in commercial customers. The number of new industrial customers added per year is relatively small.

c. Specific

Commercial Fuels - Natural gas and oil prices are expected to increase over the forecast period. Regarding availability of the conventional fuels, nothing on the horizon indicates any severe limitations in their supply, although world reserves of natural gas and oil are believed to be dwindling. There are unknown potential impacts from future changes in legislation or a change in the pricing or supply policy of oil-producing countries that might affect fuel supply. However, these cannot be quantified within the forecast. The only non-utility information source relied upon is Moody's Analytics.

Pricing Policy – Duke Energy Kentucky's electric tariffs for residential customers have a seasonal pattern. In Kentucky, an inverted rate (a block rate structure in which price increases as usage increases) is now mandatory for residential customers and a time-of-day rate has been mandated for all large commercial and industrial customers.

The purpose of the seasonal characteristics of the rate schedules is to promote conservation during summer months when demand upon electric facilities is greatest.

Year End Residential Customers - In the following table, historical and projected total year-end residential customers for the entire service area are provided.

NUMBER OF YEAR-END RESIDENTIAL CUSTOMERS

2006	118,642
2007	119,245
2008	119,997
2009	120,484
2010	120,826
2011	120,774
2012	121,674
2013	122,572
2014	123,571
2015	124,574
2016	125,495
2017	126,386
2018	127,259
2019	128,125
2020	129,002
2021	129,895
2022	130,796
2023	131,705
2024	132,630
2025	133,581
2026	134,552
2027	135,530
2028	136,531
2029	137,540
2030	138,546
2031	139,586

Appliance Efficiencies - Trends in appliance efficiencies, saturations, and usage patterns have an impact on the projected use per residential customer. Overall, the forecast incorporates a projection of increasing saturation for many appliances including heat pumps, air conditioners, electric space heating equipment, electric water heaters, electric clothes dryers, dish washers, and freezers. In addition, the forecast embodies trends of increasing appliance efficiency, including lighting, consistent with standards established by the federal government.

4. DATA BASE DOCUMENTATION

In the following sections, information on databases is provided for Duke Energy Kentucky.

The first step in the forecasting process is the collection of relevant information and data. The database discussion is broken into three parts:

1) Economic Data,
2) Energy and Peak Data, and
3) Forecast Data.

a. Economic Data

The major groups of data in the economic forecast are employment, demographics, income, production, inflation and prices. National and local values for these concepts are available from Moody's Analytics and company data.

Employment - Employment numbers are required on both a national and service area basis. Quarterly national and local employment series by industry are obtained from Moody's Analytics. Employment series are available for manufacturing and non-manufacturing sectors.

Population - National and local values for total population and population by age-cohort groups are obtained from Moody's Analytics.

Income - Local income data series are obtained from Moody's Analytics. The data is available on a county level and summed to a service area level. This includes data for personal income; dividends, interest, and rent; transfer payments; wage and salary disbursements plus other labor income; personal contributions for social insurance; and non-farm proprietors' income.

Consumer Price Index - The CPI is obtained from Moody's Analytics.

Electricity and Natural Gas Prices - The average price of electricity and natural gas is available from Duke Energy Kentucky financial reports. Data on marginal electricity price (including fuel cost) is collected for each customer class. This information is obtained from Duke Energy Kentucky records and rate schedules.

b. Energy and Peak Models

The majority of data required to develop the electricity sales and peak forecasts is obtained from the Duke Energy Kentucky service area economic data provided by Moody's Analytics, from Duke Energy Kentucky financial reports and research groups, and from national sources. With regard to the national sources of information, generally all national information is obtained from Moody's Analytics. However, local weather data are obtained from the National Oceanic and Atmospheric Administration (NOAA).

The major groups of data that are used in developing the energy forecasts are: kilowatt-hour sales by customer class, number of customers, use-per-customer, electricity prices, natural gas prices, appliance saturations, and local weather data. The following are descriptions of the adjustments performed on various groups of data to develop the final data series actually used in regression analysis.

Kilowatt-hour Sales and Revenue - Duke Energy Kentucky collects sales and revenue data monthly by rate class. For forecast purposes this information is aggregated into the following categories: residential, commercial, industrial, OPA, and the other sales categories. In the industrial sector, sales and revenue for each manufacturing NAICS are collected.

The OPA sales category is analyzed in two parts: water pumping and OPA less water-pumping sales.

Number of Customers - The number of customers by class is obtained on a monthly basis from Company records.

Use Per Customer – Average use per customer is computed on a monthly basis by dividing residential sales by total customers.

Local Weather Data - Local climatologic data are provided by NOAA for the Cincinnati/Covington airport reporting station. Cooling degree days and heating degree days are calculated on a monthly basis using temperature data. The degree day series are required on a billing cycle basis for use in regression analysis.

Appliance Stock - To account for the impact of appliance saturations and federal efficiency standards, an appliance stock variable is created. This variable is composed of three parts: appliance efficiencies, appliance saturations, and appliance energy consumption values.

The appliance stock variable is calculated as follows:

(11) Appliance $Stock_t$=

$$SUM\ (K_i * SAT_{i,t} * EFF_{i,t}) \text{ for all } i$$

Where: t = time period

i = end-use appliance

K_i = fixed energy consumption value for appliance i,

$SAT_{i,t}$ = saturation of appliance i in period t, and

$EFF_{i,t}$ = efficiency of appliance i in period t.

The appliances included in the calculation of the Appliance Stock variable are: electric range, frost-free refrigerator, manual-defrost refrigerator, food freezer, dish washer, clothes washer, clothes dryer, water heater, microwave, television, room air conditioner, central air conditioner, electric resistance heat, and electric heat pump and miscellaneous uses including lighting.

Appliance Saturation and Efficiency - In general, information on historical appliance saturations for all appliances is obtained from Company Appliance Saturation Surveys. Data on historical appliance efficiency are obtained from Itron, Inc., a forecast consulting firm. The forecast of appliance saturations and efficiencies is also obtained from data provided by Itron, Inc. They have developed Regional Statistically Adjusted End-use (SAE) Models, an end-use approach to electric forecasting that provides forward looking levels of appliance saturations and efficiencies.

Peak Weather Data - The weather conditions associated with the monthly peak load are collected from the hourly and daily data recorded by NOAA. The weather variables which influence the summer peak are maximum temperature on the peak day and the day before, morning low temperature, and humidity on the peak day. The weather influence on the winter peak is measured by the low temperatures and the associated wind speed. The variables selected are dependent upon whether it is a morning or evening winter peak load.

An average of extreme weather conditions is used as the basis for the weather component in the preparation of the peak load forecast. An average extreme weather condition can be computed using historical data for the single worst summer weather occurrence and the single worst winter weather occurrence in each year.

c. Forecast Data

Projections of exogenous variables in Duke Energy Kentucky's models are required in the following areas: national and local employment, income, industrial production, and population, as well as natural gas and electricity prices.

Employment -The forecast of employment by industry is provided by Moody's Analytics.

Income -The forecast of income is provided by Moody's Analytics.

Industrial Production - The forecast of industrial production is also provided by Moody's Analytics.

Population - Duke Energy Kentucky's population forecast, which is prepared by collecting county-level population forecasts for the counties in Duke Energy Kentucky's service area and then summing, is provided by Moody's Analytics.

Prices - The projected change in electricity and natural gas prices over the forecast interval is provided by the Company's Financial Planning and Analysis department and Moody's Analytics.

d. Load Research and Market Research Efforts

Duke Energy Kentucky is committed to the continued development and maintenance of a substantive class load database of typical customer electricity consumption patterns and the collection of primary market research data on customers.

Load Research – Complete load profile information, or 100% sample data, is maintained upon commercial and industrial customers whose average annual demand is greater than 500 kW. Additionally, Duke Energy Kentucky continues to collect whole premise or building level electricity consumption patterns on representative samples of the various customer classes and rate groups whose annual demands are less than 500 kW.

Periodically, Duke Energy Kentucky monitors selected end-uses or systems associated with energy efficiency evaluations performed in conjunction with energy efficiency programs. These studies are performed as necessary and tend to be of a shorter duration.

Market Research - Primary research projects continue to be conducted as part of the on-going efforts to gain knowledge about Duke Energy Kentucky's customers. These projects include customer satisfaction studies, appliance saturation studies, end-use studies, studies to track competition (to monitor customer switching percentages in order to forecast future utility load), and related types of marketing research projects.

5. MODELS

Specific analytical techniques have been employed for development of the forecast models.

a. Specific Analytical Techniques

Regression Analysis - Ordinary least squares is the principle regression technique employed to estimate economic/behavioral relationships among the relevant variables. This econometric technique provides a method to perform quantitative analysis of economic behavior.

Ordinary least-squares techniques were used to model electric sales. Based upon their relationship with the dependent variable, several independent variables were tested in the regression models. The final models were chosen based upon their statistical strength and logical consistency.

Logarithmic Transformations - The projection of economic relationships over time requires the use of techniques that can account for non-linear relationships. By transforming the dependent variable and independent variables into their "natural logarithm", a non-linear relationship can be transformed into a linear relationship for model estimation purposes.

Polynomial Distributed Lag Structure - One method of accounting for the lag between a change in one variable and its ultimate impact on another variable is through the use of polynomial distributed lags. This technique is also referred to as Almon lags. Polynomial Distributed Lag Structures derive their name from the fact that the lag weights follow a polynomial of specified degree. That is, the lag weights all lie on a line, parabola, or higher order polynomial as required.

This technique is employed in developing econometric models for most of the energy equations.

Serial Correlation - It is often the case in forecasting an economic time series that residual errors in one period are related to those in a previous period. This is known as serial correlation. By correcting for this serial correlation of the estimated residuals, forecast error is reduced and the estimated coefficients are more efficient. The Marquardt algorithm is employed to correct for the existence of autocorrelation.

Qualitative Variables - In several equations, qualitative variables are employed. In estimating an econometric relation using time series data, it is quite often the case that "outliers" are present in the historic data. These unusual deviations in the data can be the result of problems such as errors in the reporting of data by particular companies and agencies, labor-management disputes, severe energy shortages or restrictions, and other perturbations that do not repeat with predictability. Therefore, in order to identify the true underlying economic relationship between the dependent variable and the other independent variables, qualitative variables are employed to account for the impact of the out. The coefficient for the qualitative variable must be statistically significant, have a sign in the expected direction, and make an improvement to model fit statistics.

b. Relationships Between The Specific Techniques

The manner in which specific methodologies for forecasting components of the total load are related is explained in the discussion of specific analytical techniques above.

c. Alternative Methodologies

Duke Energy Kentucky continues to use the current forecasting methodology as it has for the past several years. Duke Energy Kentucky considers the forecasting methods currently utilized to be adequate.

d. Changes In Methodology

The Company changed its approach regarding the development of its appliance stock variable to rely more completely on information from Itron, Inc. for estimates of historical appliance efficiency. The Company uses the latest historical data available and relies on recent economic data and forecasts from Moody's Analytics.

e. Computer Software

All of the equations in the Electric Energy Forecast Model and Electric Peak Load Model were estimated and forecasted on personal computers using the Eviews software from Quantitative Micro Software, LLC.

f. Equations

Following is a display of all the relevant equations used in the forecast. Specifically, for each of the equations in the Electric Energy Forecast Model and Electric Peak Load Model the following information is included:

Equation Estimation Results - The results of the estimation of each of the stochastic equations in the models is provided. Included are the estimated coefficients and the results of appropriate statistical tests. Those equations which required a correction for serial correlation are so indicated.

The computer output for each variable lists the estimated coefficient, standard error, and the t statistic. Lagged variables are denoted with the \-N symbol, "N" being the number of periods lagged.

The use of Polynomial Distributed Lags (PDL) is indicated by the expression: PDL followed by a number signifying the PDL variable number. The PDL is defined using the degree of the polynomial, the length of lag, and the restrictions. The restrictions may constrain the PDL such that the end values of the distributed lag are close to zero. The computer output for each PDL variable lists the estimated lag weights and their associated standard errors. There is also a plot of the distributed lag. In addition to the individual lag weights, statistics are presented on the sum and average of the lag weights.

EQUATIONS USED IN FORECAST

Service Area Electric Customers – Residential

Dependent Variable: LOG(CUSRES_OH_KY)
Method: Least Squares
Date: 02/22/11 Time: 12:53
Sample: 1989M10 2010M12
Included observations: 255
Convergence achieved after 7 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
@MONTH=1	14.77528	3.476269	4.250328	0.0000
@MONTH=2	14.77606	3.476271	4.250548	0.0000
@MONTH=3	14.77619	3.476272	4.250585	0.0000
@MONTH=4	14.77461	3.476271	4.250132	0.0000
@MONTH=5	14.77171	3.476268	4.249301	0.0000
@MONTH=7	14.76918	3.476263	4.248581	0.0000
@MONTH=8	14.76796	3.476261	4.248232	0.0000
@MONTH=9	14.76739	3.476259	4.248070	0.0000
@MONTH=10	14.76912	3.476263	4.248561	0.0000
(@MONTH=6)+(@MONTH=11)	14.77052	3.476265	4.248962	0.0000
@MONTH=12	14.77363	3.476264	4.249857	0.0000
@ISPERIOD("1994M05")	-0.005035	0.001281	-3.932009	0.0001
@ISPERIOD("2001m02")	0.028551	0.001652	17.28378	0.0000
@ISPERIOD("2001m03")	0.008740	0.002084	4.193195	0.0000
@ISPERIOD("2001m04")	0.007463	0.002210	3.377294	0.0009
@ISPERIOD("2001m05")	0.028774	0.002081	13.82542	0.0000
@ISPERIOD("2001m06")	0.015467	0.001637	9.451164	0.0000
@ISPERIOD("2003m12")	-0.004948	0.001474	-3.357548	0.0009
@ISPERIOD("2004m01")	0.003394	0.001476	2.298880	0.0224
@ISPERIOD("2005m02")	-0.003342	0.001281	-2.609005	0.0097
@ISPERIOD("2006m02")	-0.002619	0.001281	-2.044769	0.0420
@ISPERIOD("2007m04")	-0.002782	0.001279	-2.174691	0.0307
@ISPERIOD("2009m05")	-0.005493	0.001281	-4.287902	0.0000
PDL01	0.006679	0.003382	1.974954	0.0495
AR(1)	0.999353	0.002004	498.7187	0.0000

R-squared	0.999392	Mean dependent var	13.42009
Adjusted R-squared	0.999329	S.D. dependent var	0.067997
S.E. of regression	0.001761	Akaike info criterion	-9.752425
Sum squared resid	0.000714	Schwarz criterion	-9.405242
Log likelihood	1268.434	Hannan-Quinn criter.	-9.612773
Durbin-Watson stat	1.993809		

Inverted AR Roots 1.00

Lag Distribution of LOG(YP_OH_KY/N_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
. * |	0	0.00607	0.00307	1.97495
. * |	1	0.01093	0.00553	1.97495
. * |	2	0.01457	0.00738	1.97495
. * |	3	0.01700	0.00861	1.97495
. *|	4	0.01822	0.00922	1.97495
. *|	5	0.01822	0.00922	1.97495
. * |	6	0.01700	0.00861	1.97495
. * |	7	0.01457	0.00738	1.97495
. * |	8	0.01093	0.00553	1.97495
. * |	9	0.00607	0.00307	1.97495
	Sum of Lags	0.13358	0.06764	1.97495

KWH USE PER CUSTOMER – RESIDENTIAL

Dependent Variable: LOG(KWHRES_OH_KY/CUSRES_OH_KY)
Method: Least Squares
Date: 02/22/11 Time: 17:22
Sample: 1998M01 2010M12
Included observations: 156
Convergence achieved after 11 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.514845	1.115202	-0.461661	0.6451
LOG(APPLSTK_EFF_OH_KY*(YP_OH_KY/N_OH_KY/CPI))	0.917152	0.143311	6.399716	0.0000
(D_DJF)*(SAT_EH_EFF)*HDDB_OH_KY_59_0_500	0.003158	0.000126	25.03541	0.0000
(1-D_DJF)*(SAT_EH_EFF)*HDDB_OH_KY_59_0_500	0.002783	0.000149	18.67755	0.0000
(D_DJF)*(SAT_EH_EFF)*HDDB_OH_KY_59_500	0.002237	9.63E-05	23.23251	0.0000
(1-D_DJF)*(SAT_EH_EFF)*HDDB_OH_KY_59_500	0.003034	0.000238	12.73487	0.0000
(D_JJA)*(SAT_CAC_EFF)*CDDB_OH_KY_65_0_100	0.005602	0.000449	12.47811	0.0000
(1-D_JJA)*(SAT_CAC_EFF)*CDDB_OH_KY_65_0_100	0.007240	0.000359	20.14954	0.0000
(D_JJA)*(SAT_CAC_EFF)*CDDB_OH_KY_65_100	0.001446	0.000319	4.532283	0.0000
(1-D_JJA)*(SAT_CAC_EFF)*CDDB_OH_KY_65_100	0.001417	0.000404	3.506665	0.0006
(D_JJA+(@MONTH=5)+(@MONTH=9))*(SAT_RAC_EFF)*CDDB_OH_KY_65	0.003962	0.000411	9.636836	0.0000
@MONTH=1	0.103920	0.006545	15.87673	0.0000
@MONTH=5	-0.047385	0.009273	-5.110109	0.0000
@MONTH=7	0.076130	0.010368	7.342619	0.0000
@MONTH=8	0.061891	0.012905	4.795728	0.0000
@MONTH=12	0.061894	0.008190	7.557223	0.0000
@ISPERIOD("2001m04")	-0.048687	0.020563	-2.367680	0.0194
@ISPERIOD("2001m05")	-0.098768	0.021593	-4.574078	0.0000
@ISPERIOD("2002m05")+@ISPERIOD("2004m05")	-0.043707	0.014726	-2.967941	0.0036
@ISPERIOD("2005m01")	0.080274	0.018672	4.299069	0.0000
@ISPERIOD("2007m05")	-0.082077	0.019906	-4.123167	0.0001
@ISPERIOD("2007m10")	0.082826	0.020268	4.086511	0.0001
@ISPERIOD("2008m10")	-0.062908	0.019367	-3.248155	0.0015
@ISPERIOD("2010m10")	-0.044210	0.019111	-2.313270	0.0223
@ISPERIOD("2004m06")	0.052896	0.019490	2.713963	0.0076
@ISPERIOD("2010m05")	-0.068642	0.019277	-3.560903	0.0005
PDL01	-0.039970	0.022929	-1.743183	0.0837
AR(1)	0.524912	0.077534	6.770093	0.0000

R-squared	0.992259	Mean dependent var	6.887594
Adjusted R-squared	0.990626	S.D. dependent var	0.206988
S.E. of regression	0.020040	Akaike info criterion	-4.821019
Sum squared resid	0.051405	Schwarz criterion	-4.273609
Log likelihood	404.0395	Hannan-Quinn criter.	-4.598685
F-statistic	607.6934	Durbin-Watson stat	1.843885
Prob(F-statistic)	0.000000		

Inverted AR Roots	.52

Lag Distribution of LOG(APPLSTK_EFF_OH_KY*(MP_RES_OH_KY/CPI))	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.03997	0.02293	-1.74318
* . |	1	-0.01998	0.01146	-1.74318
	Sum of Lags	-0.05995	0.03439	-1.74318

KWH SALES – COMMERCIAL

Dependent Variable: LOG(KWHCOM_OH_KY)
Method: Least Squares
Date: 03/04/11 Time: 16:41
Sample: 1986M01 2010M12
Included observations: 300
Convergence achieved after 12 iterations
MA Backcast: 1985M12

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	10.03173	0.597318	16.79462	0.0000
LOG(ECOM_OH_KY)	1.472330	0.094699	15.54747	0.0000
LOG(DS_KWH_COM_OH_KY(-1)/CPI(-1))	-0.048246	0.023053	-2.092865	0.0373
(@MONTH=11)*HDDB_OH_KY_59	6.88E-05	2.64E-05	2.602332	0.0098
(@MONTH=12)*HDDB_OH_KY_59	0.000188	1.18E-05	15.85891	0.0000
(@MONTH=1)*HDDB_OH_KY_59	0.000192	8.38E-06	22.94841	0.0000
(@MONTH=2)*HDDB_OH_KY_59	0.000127	8.89E-06	14.34678	0.0000
(@MONTH=3)*HDDB_OH_KY_59	0.000108	1.09E-05	9.897655	0.0000
(@MONTH=4)*HDDB_OH_KY_59	8.00E-05	1.93E-05	4.146326	0.0000
(@MONTH=5)*CDDB_OH_KY_65	0.000975	0.000152	6.425203	0.0000
(@MONTH=6)*CDDB_OH_KY_65_0_100	0.001323	7.92E-05	16.69725	0.0000
(@MONTH=6)*CDDB_OH_KY_65_100	0.000716	7.60E-05	9.425939	0.0000
(@MONTH=7)*CDDB_OH_KY_65_0_100	0.001814	0.000153	11.82619	0.0000
(@MONTH=7)*CDDB_OH_KY_65_100	0.000467	7.42E-05	6.292792	0.0000
(@MONTH=8)*CDDB_OH_KY_65_0_100	0.001382	0.000130	10.64329	0.0000
(@MONTH=8)*CDDB_OH_KY_65_100	0.000617	4.98E-05	12.39518	0.0000
(@MONTH=9)*CDDB_OH_KY_65_0_100	0.001748	0.000106	16.44290	0.0000
(@MONTH=9)*CDDB_OH_KY_65_100	0.000457	5.68E-05	8.045500	0.0000
(@MONTH=10)*CDDB_OH_KY_65	0.000703	8.58E-05	8.195241	0.0000
@MONTH=10	0.027646	0.009710	2.847026	0.0048
@ISPERIOD("1991m04")	0.097466	0.016830	5.791198	0.0000
@ISPERIOD("1991m11")	0.058418	0.017119	3.412397	0.0007
@ISPERIOD("1993m09")	-0.120572	0.017595	-6.852518	0.0000
@ISPERIOD("1993m10")+@ISPERIOD("2004m12")+@ISPERIOD("2007m04")	0.044787	0.010405	4.304534	0.0000
@ISPERIOD("1995m04")	0.054237	0.018635	2.910520	0.0039
@ISPERIOD("1995M05")	-0.086021	0.018781	-4.580158	0.0000
@ISPERIOD("1998m05")	0.063831	0.016709	3.820089	0.0002
@ISPERIOD("1998m07")	0.053064	0.016868	3.145907	0.0018
@ISPERIOD("2000m01")+@ISPERIOD("2000m07")	-0.060989	0.012729	-4.791479	0.0000
@ISPERIOD("2000m08")	0.043076	0.018058	2.385449	0.0178
@ISPERIOD("2000m10")	0.086526	0.016861	5.131709	0.0000
@ISPERIOD("1993m11")+@ISPERIOD("2002m08")+@ISPERIOD("2004m11")+@ISPERIOD("2004m03") +@ISPERIOD("2005m02")+@ISPERIOD("2005m08")	-0.050026	0.007274	-6.877750	0.0000
@ISPERIOD("2002m04")	0.055491	0.016838	3.295599	0.0011
@ISPERIOD("2005m03")+@ISPERIOD("1999m02")	-0.028477	0.011880	-2.397000	0.0172
@ISPERIOD("2010m02")	-0.092050	0.017152	-5.366674	0.0000
AR(2)	0.797924	0.049527	16.11088	0.0000
MA(1)	0.829177	0.045827	18.09353	0.0000

R-squared	0.991621	Mean dependent var	20.05652
Adjusted R-squared	0.990474	S.D. dependent var	0.219772
S.E. of regression	0.021450	Akaike info criterion	-4.731100
Sum squared resid	0.121012	Schwarz criterion	-4.274300
Log likelihood	746.6650	Hannan-Quinn criter.	-4.548288
F-statistic	864.5352	Durbin-Watson stat	2.213320
Prob(F-statistic)	0.000000		

Inverted AR Roots	.89	-.89
Inverted MA Roots	-.83	

MWH SALES – INDUSTRIAL – FOOD, BEVERAGE AND TOBACCO

Dependent Variable: LOG(MWHN311_312_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 12:58
Sample: 1980Q1 2010Q4
Included observations: 124
Convergence achieved after 14 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	10.50195	0.424660	24.73025	0.0000
LOG(JQINDN311_312_OH_KY(-3))	0.349835	0.194308	1.800411	0.0745
LOG(DS_KWH_IND_OH_KY/CPI)	-0.114501	0.048419	-2.364800	0.0198
CDDB_OH_KY_65	0.000165	1.31E-05	12.64796	0.0000
HDDB_OH_KY_59	-3.05E-05	5.27E-06	-5.777112	0.0000
D_1965Q1_1990Q4	-0.295112	0.046512	-6.344824	0.0000
@ISPERIOD("1991q1")+@ISPERIOD("2000q3")	-0.152495	0.031910	-4.778932	0.0000
@ISPERIOD("2007q4")	0.141740	0.042345	3.347297	0.0011
@ISPERIOD("2008q4")+@ISPERIOD("2009q1")	0.149226	0.043009	3.469609	0.0007
D_1976Q1_1989Q2+D_1987Q1_1991Q3	-0.086445	0.027814	-3.107943	0.0024
@ISPERIOD("1993q2")	-0.108494	0.042446	-2.556059	0.0120
@ISPERIOD("1992q2")	-0.162981	0.042087	-3.872467	0.0002
D_1980Q1_2005Q2	-0.076237	0.032984	-2.311303	0.0227
AR(1)	0.719013	0.074756	9.618118	0.0000

R-squared	0.970883	Mean dependent var	11.31940
Adjusted R-squared	0.967441	S.D. dependent var	0.285979
S.E. of regression	0.051602	Akaike info criterion	-2.984504
Sum squared resid	0.292905	Schwarz criterion	-2.666085
Log likelihood	199.0393	Hannan-Quinn criter.	-2.855155
F-statistic	282.1387	Durbin-Watson stat	2.010146
Prob(F-statistic)	0.000000		

Inverted AR Roots	.72

MWH SALES – INDUSTRIAL – PAPER, PLASTIC AND RUBBER

Dependent Variable: LOG(MWHN322_326_OH_KY)
Method: Least Squares
Date: 02/22/11 Time: 08:40
Sample: 1979Q1 2010Q4
Included observations: 128
Convergence achieved after 13 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LOG(JQINDN322_326_OH_KY)	0.309810	0.168334	1.840453	0.0683
@ISPERIOD("1992q1")+@ISPERIOD("1993q1")	0.051513	0.016989	3.032060	0.0030
@ISPERIOD("2001q2")	-0.203553	0.024566	-8.285811	0.0000
@ISPERIOD("2003q4")+@ISPERIOD("1996q3")	-0.088605	0.016437	-5.390512	0.0000
@ISPERIOD("2005q1")	0.124963	0.023737	5.264399	0.0000
HDDB_OH_KY_59*D_1999Q1_2001Q2	-2.15E-05	8.14E-06	-2.639061	0.0095
@ISPERIOD("2000q3")	0.093176	0.023828	3.910416	0.0002
@ISPERIOD("1990q2")+@ISPERIOD("2010q2")	-0.053079	0.016964	-3.128934	0.0022
@QUARTER=1	9.894756	0.852062	11.61272	0.0000
@QUARTER=2	9.945191	0.852586	11.66474	0.0000
@QUARTER=3	9.961354	0.852341	11.68705	0.0000
@QUARTER=4	9.930137	0.852097	11.65377	0.0000
PDL01	-0.061645	0.029480	-2.091070	0.0388
PDL02	-0.024528	0.013997	-1.752412	0.0824
AR(1)	1.083638	0.097795	11.08066	0.0000
AR(2)	-0.165519	0.096048	-1.723287	0.0876

R-squared	0.957649	Mean dependent var	11.97044
Adjusted R-squared	0.951977	S.D. dependent var	0.156135
S.E. of regression	0.034216	Akaike info criterion	-3.795786
Sum squared resid	0.131121	Schwarz criterion	-3.439282
Log likelihood	258.9303	Hannan-Quinn criter.	-3.650937
Durbin-Watson stat	1.994581		

Inverted AR Roots	.90	.18

Lag Distribution of LOG(DS_KW_IND_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.08219	0.03931	-2.09107
* . |	1	-0.06165	0.02948	-2.09107
* . |	2	-0.04110	0.01965	-2.09107
* . |	3	-0.02055	0.00983	-2.09107
	Sum of Lags	-0.20548	0.09827	-2.09107

Lag Distribution of LOG(DS_KWH_IND_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.04292	0.02449	-1.75241
* . |	1	-0.03679	0.02099	-1.75241
* . |	2	-0.03066	0.01750	-1.75241
* . |	3	-0.02453	0.01400	-1.75241
* . |	4	-0.01840	0.01050	-1.75241
* . |	5	-0.01226	0.00700	-1.75241
* . |	6	-0.00613	0.00350	-1.75241
	Sum of Lags	-0.17169	0.09798	-1.75241

MWH SALES – INDUSTRIAL – CHEMICALS

Dependent Variable: LOG(MWHN325_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13:04
Sample: 1978Q1 2010Q4
Included observations: 132
Convergence achieved after 20 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	10.28476	0.792054	12.98493	0.0000
LOG(JQINDN325_OH_KY)	0.486093	0.124505	3.904195	0.0002
CDDB_OH_KY_65	9.97E-05	8.17E-06	12.19917	0.0000
@ISPERIOD("1994q1")	-0.077933	0.036333	-2.144959	0.0339
@ISPERIOD("2003q4")	0.091963	0.037040	2.482807	0.0144
@ISPERIOD("2000q4")	0.080947	0.037184	2.176911	0.0314
@ISPERIOD("2009q2")	-0.131512	0.038205	-3.442319	0.0008
PDL01	-0.043777	0.017428	-2.511874	0.0133
AR(1)	0.569665	0.094034	6.058096	0.0000
AR(2)	0.352997	0.096003	3.676941	0.0004

R-squared	0.964301	Mean dependent var	12.33676
Adjusted R-squared	0.961668	S.D. dependent var	0.220981
S.E. of regression	0.043265	Akaike info criterion	-3.370200
Sum squared resid	0.228369	Schwarz criterion	-3.151806
Log likelihood	232.4332	Hannan-Quinn criter.	-3.281455
F-statistic	366.1631	Durbin-Watson stat	1.953791
Prob(F-statistic)	0.000000		

Inverted AR Roots	.94	-.37

Lag Distribution of LOG(TS_KWH_IND_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
* .|	0	-0.06567	0.02614	-2.51187
* .|	1	-0.05472	0.02179	-2.51187
* .|	2	-0.04378	0.01743	-2.51187
* .|	3	-0.03283	0.01307	-2.51187
* .|	4	-0.02189	0.00871	-2.51187
* .|	5	-0.01094	0.00436	-2.51187
	Sum of Lags	-0.22983	0.09150	-2.51187

MWH SALES – INDUSTRIAL – PRIMARY METALS – BUTLER

Dependent Variable: LOG(MWHN331_BUTLER-BASE)
Method: Least Squares
Date: 02/18/11 Time: 13:05
Sample: 1985Q1 2010Q4
Included observations: 104
Convergence achieved after 11 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	11.54289	0.475030	24.29927	0.0000
(1-D_1965Q1_1985Q4)*LOG(TS_KWH_IND_OH_KY/CPI)	-0.008049	0.004027	-1.999083	0.0487
LOG(TS_KWH_IND_OH_KY(-5)/APGIND_OH_KY(-5))	-0.070697	0.023743	-2.977573	0.0038
@ISPERIOD("2009q2")	-0.380330	0.035585	-10.68799	0.0000
@ISPERIOD("2009q1")	-0.185576	0.034136	-5.436410	0.0000
D_1965Q1_1995Q4	-0.151179	0.033208	-4.552514	0.0000
@ISPERIOD("1998q3")	-0.118403	0.028031	-4.224004	0.0001
@ISPERIOD("1990q2")	-0.083181	0.028377	-2.931266	0.0043
@ISPERIOD("2008q4")	-0.111339	0.032228	-3.454775	0.0009
@ISPERIOD("1991q3")	-0.094316	0.029815	-3.163375	0.0021
@ISPERIOD("1986q3")	-0.071409	0.028216	-2.530772	0.0132
@ISPERIOD("1991q4")	0.056292	0.029192	1.928352	0.0571
@ISPERIOD("2001q1")	-0.078628	0.028031	-2.805044	0.0062
PDL01	0.196650	0.045579	4.314501	0.0000
PDL02	-0.112835	0.064230	-1.756746	0.0825
AR(1)	0.607956	0.105443	5.765747	0.0000
AR(2)	0.361086	0.104754	3.446999	0.0009

R-squared	0.979879	Mean dependent var	12.61955
Adjusted R-squared	0.976178	S.D. dependent var	0.221847
S.E. of regression	0.034241	Akaike info criterion	-3.762375
Sum squared resid	0.102000	Schwarz criterion	-3.330118
Log likelihood	212.6435	Hannan-Quinn criter.	-3.587255
F-statistic	264.7997	Durbin-Watson stat	1.944391
Prob(F-statistic)	0.000000		

Inverted AR Roots	.98	-.37

Lag Distribution of LOG(JQINDN331_BUTLER)	i	Coefficient	Std. Error	t-Statistic
. * |	0	0.19665	0.04558	4.31450
. * |	1	0.09832	0.02279	4.31450
	Sum of Lags	0.29497	0.06837	4.31450

Lag Distribution of LOG(TS_KW_IND_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.11284	0.06423	-1.75675
* . |	1	-0.05642	0.03211	-1.75675
	Sum of Lags	-0.16925	0.09634	-1.75675

MWH SALES – INDUSTRIAL – PRIMARY METALS – LESS BUTLER

Dependent Variable: LOG(MWHN331LBUTLER_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13:07
Sample: 1987Q1 2010Q4
Included observations: 96
Convergence achieved after 9 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	7.245961	0.959964	7.548156	0.0000
@ISPERIOD("1999q1")	-0.402581	0.071569	-5.625043	0.0000
@ISPERIOD("1988q4")	-0.203375	0.071421	-2.847565	0.0055
@ISPERIOD("1996q3")+@ISPERIOD("1997q3")	-0.252081	0.050789	-4.963296	0.0000
D_1998Q3_2001Q2	0.774640	0.054284	14.27017	0.0000
D_1965Q1_1998Q2	1.097773	0.040415	27.16255	0.0000
@ISPERIOD("2002q2")	-0.326168	0.072427	-4.503412	0.0000
@ISPERIOD("2003q1")	-0.155829	0.072110	-2.160995	0.0335
PDL01	0.300736	0.073052	4.116739	0.0001
PDL02	-0.113535	0.031400	-3.615828	0.0005
AR(1)	0.611689	0.092466	6.615247	0.0000
AR(3)	-0.191377	0.079864	-2.396267	0.0188

R-squared	0.976734	Mean dependent var	11.09645
Adjusted R-squared	0.973687	S.D. dependent var	0.518957
S.E. of regression	0.084181	Akaike info criterion	-1.995227
Sum squared resid	0.595261	Schwarz criterion	-1.674683
Log likelihood	107.7709	Hannan-Quinn criter.	-1.865658
F-statistic	320.5839	Durbin-Watson stat	2.242857
Prob(F-statistic)	0.000000		

Inverted AR Roots	.52-.42i	.52+.42i	-.43

Lag Distribution of LOG(JQINDN331_CMSA)	i	Coefficient	Std. Error	t-Statistic
. * |	0	0.30074	0.07305	4.11674
. * |	1	0.15037	0.03653	4.11674
	Sum of Lags	0.45110	0.10958	4.11674

Lag Distribution of LOG(TS_KWH_IND_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.15138	0.04187	-3.61583
* . |	1	-0.11354	0.03140	-3.61583
* . |	2	-0.07569	0.02093	-3.61583
* . |	3	-0.03785	0.01047	-3.61583
	Sum of Lags	-0.37845	0.10467	-3.61583

MWH SALES – INDUSTRIAL – FABRICATED METALS

Dependent Variable: LOG(MWHN332_OH_KY)
Method: Least Squares
Date: 05/06/11 Time: 11:46
Sample: 1984Q1 2010Q4
Included observations: 108
Convergence achieved after 7 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	10.92849	0.180443	60.56472	0.0000
LOG(JQINDN332_OH_KY)	0.449144	0.149219	3.009954	0.0033
LOG(DS_KWH_IND_OH_KY/WPI0561)	-0.035225	0.014375	-2.450477	0.0160
D_2000Q3_2001Q2	0.184784	0.021119	8.749484	0.0000
@ISPERIOD("2009q1")+@ISPERIOD("2009q2")	-0.114032	0.022081	-5.164267	0.0000
CDDB_OH_KY_65	6.27E-05	5.86E-06	10.69503	0.0000
@ISPERIOD("2000q1")+@ISPERIOD("1988q3")	-0.042499	0.015110	-2.812634	0.0059
@ISPERIOD("1986q3")	-0.074790	0.021510	-3.476921	0.0008
@ISPERIOD("2001q1")	0.083925	0.021116	3.974499	0.0001
AR(1)	0.966756	0.032927	29.36071	0.0000

R-squared	0.940692	Mean dependent var	11.27337
Adjusted R-squared	0.935245	S.D. dependent var	0.115249
S.E. of regression	0.029328	Akaike info criterion	-4.132559
Sum squared resid	0.084290	Schwarz criterion	-3.884214
Log likelihood	233.1582	Hannan-Quinn criter.	-4.031864
F-statistic	172.7091	Durbin-Watson stat	2.009184
Prob(F-statistic)	0.000000		

Inverted AR Roots	.97

MWH SALES – INDUSTRIAL – MACHINERY

Dependent Variable: LOG(MWHN333_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13:11
Sample: 1982Q4 2010Q4
Included observations: 113
Convergence achieved after 9 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LOG(JQINDN333_OH_KY)	0.503092	0.120403	4.178396	0.0001
LOG(DS_KW_IND_OH_KY(-8)/CPI(-8))	-0.322183	0.129203	-2.493630	0.0143
LOG(DS_KWH_IND_OH_KY/APGIND_OH_KY)	-0.047762	0.026667	-1.791068	0.0763
CDDB_OH_KY_65*(1-D_1965Q1_1986Q4)	8.27E-05	1.95E-05	4.248634	0.0000
@ISPERIOD("1998q4")	0.065967	0.030046	2.195512	0.0305
D_1965Q1_2001Q2	0.152257	0.038175	3.988430	0.0001
@ISPERIOD("2009q1")	-0.081080	0.030330	-2.673219	0.0088
@ISPERIOD("2000q2")	-0.281998	0.034988	-8.059888	0.0000
@ISPERIOD("2000q1")	-0.075197	0.034782	-2.161935	0.0330
@QUARTER=1	9.423331	0.466364	20.20596	0.0000
@QUARTER=2	9.414453	0.465468	20.22577	0.0000
@QUARTER=3	9.434672	0.462262	20.40980	0.0000
@QUARTER=4	9.414505	0.465407	20.22853	0.0000
AR(1)	0.890755	0.046713	19.06876	0.0000

R-squared	0.931419	Mean dependent var	10.82105
Adjusted R-squared	0.922414	S.D. dependent var	0.141517
S.E. of regression	0.039419	Akaike info criterion	-3.513634
Sum squared resid	0.153829	Schwarz criterion	-3.175728
Log likelihood	212.5203	Hannan-Quinn criter.	-3.376515
Durbin-Watson stat	1.869360		

Inverted AR Roots	.89

MWH SALES – INDUSTRIAL – COMPUTER AND ELECTRONICS

Dependent Variable: LOG(MWHN334_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13:12
Sample: 1980Q1 2010Q4
Included observations: 124
Convergence achieved after 14 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	7.636820	0.785829	9.718169	0.0000
LOG(JQINDN334_OH_KY)	0.068654	0.023298	2.946718	0.0039
CDDB_OH_KY_65	0.000110	8.49E-06	12.96695	0.0000
@ISPERIOD("1986q3")	-0.075276	0.033735	-2.231351	0.0276
@ISPERIOD("1992q2")	-0.114736	0.033268	-3.448810	0.0008
@ISPERIOD("1988q4")	0.128977	0.033545	3.844941	0.0002
@ISPERIOD("2002q1")	-0.102444	0.033293	-3.077074	0.0026
@ISPERIOD("2010q2")	-0.176752	0.044545	-3.967914	0.0001
1-@ISPERIOD("2010q3")-@ISPERIOD("2010q4")	0.348847	0.059188	5.893851	0.0000
@ISPERIOD("2009Q1")	-0.110379	0.033326	-3.312139	0.0012
PDL01	-0.054523	0.015581	-3.499310	0.0007
AR(1)	0.835586	0.057735	14.47272	0.0000

R-squared	0.963975	Mean dependent var	10.76919
Adjusted R-squared	0.960437	S.D. dependent var	0.217775
S.E. of regression	0.043316	Akaike info criterion	-3.348802
Sum squared resid	0.210147	Schwarz criterion	-3.075871
Log likelihood	219.6257	Hannan-Quinn criter.	-3.237931
F-statistic	272.4499	Durbin-Watson stat	1.768787
Prob(F-statistic)	0.000000		

Inverted AR Roots	.84

Lag Distribution of LOG(DS_KWH_IND_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.04544	0.01298	-3.49931
* . |	1	-0.07270	0.02077	-3.49931
* . |	2	-0.08178	0.02337	-3.49931
* . |	3	-0.07270	0.02077	-3.49931
* . |	4	-0.04544	0.01298	-3.49931
	Sum of Lags	-0.31805	0.09089	-3.49931

MWH SALES – INDUSTRIAL – ELEC. EQUIPMENT, APPLIANCE & COMPONENT

Dependent Variable: LOG(MWHN335_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13:13
Sample: 1984Q1 2010Q4
Included observations: 108
Convergence achieved after 11 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LOG(DS_KWH_IND_OH_KY/WPI0561)	-0.045043	0.016224	-2.776292	0.0067
@ISPERIOD("1988q3")	-0.083343	0.020768	-4.013147	0.0001
@ISPERIOD("1998q3")	-0.066663	0.020910	-3.188013	0.0020
@ISPERIOD("2009q1")+@ISPERIOD("2009q2")	-0.235459	0.029168	-8.072589	0.0000
@ISPERIOD("2008q4")	-0.099709	0.026210	-3.804251	0.0003
@ISPERIOD("1986q3")+@ISPERIOD("1992q2")	-0.073565	0.014501	-5.073269	0.0000
@ISPERIOD("2002q3")	0.065103	0.020910	3.113398	0.0025
@ISPERIOD("1999q1")	-0.057785	0.020907	-2.763877	0.0069
@QUARTER=1	8.052516	1.216334	6.620316	0.0000
@QUARTER=2	8.059279	1.216439	6.625307	0.0000
@QUARTER=3	8.083518	1.216455	6.645142	0.0000
@QUARTER=4	8.062102	1.216512	6.627227	0.0000
PDL01	0.096288	0.050134	1.920602	0.0579
PDL02	-0.012352	0.006802	-1.816043	0.0726
AR(1)	1.147741	0.114382	10.03425	0.0000
AR(2)	-0.235883	0.113489	-2.078473	0.0405

R-squared	0.965821	Mean dependent var	10.54494
Adjusted R-squared	0.960248	S.D. dependent var	0.156964
S.E. of regression	0.031295	Akaike info criterion	-3.954751
Sum squared resid	0.090104	Schwarz criterion	-3.557398
Log likelihood	229.5565	Hannan-Quinn criter.	-3.793639
Durbin-Watson stat	1.904155		

Inverted AR Roots .88 .27

Lag Distribution of LOG(JQINDN335_OH_KY)	i	Coefficient	Std. Error	t-Statistic
. * |	0	0.12838	0.06685	1.92060
. * |	1	0.09629	0.05013	1.92060
. * |	2	0.06419	0.03342	1.92060
. * |	3	0.03210	0.01671	1.92060
	Sum of Lags	0.32096	0.16711	1.92060

Lag Distribution of LOG(DS_KWH_IND_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.01123	0.00618	-1.81604
* . |	1	-0.02021	0.01113	-1.81604
* . |	2	-0.02695	0.01484	-1.81604
* . |	3	-0.03144	0.01731	-1.81604
* . |	4	-0.03369	0.01855	-1.81604
* . |	5	-0.03369	0.01855	-1.81604
* . |	6	-0.03144	0.01731	-1.81604
* . |	7	-0.02695	0.01484	-1.81604
* . |	8	-0.02021	0.01113	-1.81604
* . |	9	-0.01123	0.00618	-1.81604
	Sum of Lags	-0.24704	0.13603	-1.81604

MWH SALES – INDUSTRIAL – MOTOR VEHICLES AND PARTS

Dependent Variable: LOG(MWHN3361_62_63_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13:15
Sample: 1983Q1 2010Q4
Included observations: 112
Convergence achieved after 5 iterations
MA Backcast: 1982Q2 1982Q4

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	8.051917	0.520185	15.47896	0.0000
LOG(TS_KWH_IND_OH_KY(-6)/WPI0561(-6))	-0.063659	0.032882	-1.935967	0.0558
CDDB_OH_KY_65	9.43E-05	1.49E-05	6.346838	0.0000
@ISPERIOD("1999q1")	0.541207	0.058225	9.295131	0.0000
@ISPERIOD("2000q1")	0.195837	0.059601	3.285824	0.0014
@ISPERIOD("2004q4")	-0.270881	0.058810	-4.605995	0.0000
D_1965Q1_2005Q1	0.230177	0.048607	4.735464	0.0000
@ISPERIOD("2008q3")	-0.219970	0.064779	-3.395720	0.0010
@ISPERIOD("2008q4")	-0.241327	0.068775	-3.508926	0.0007
@ISPERIOD("2009q1")	-0.296137	0.066781	-4.434421	0.0000
@ISPERIOD("1991q1")	-0.131337	0.058181	-2.257392	0.0262
PDL01	0.081793	0.024827	3.294454	0.0014
PDL02	-0.174030	0.030342	-5.735555	0.0000
AR(1)	0.441387	0.097294	4.536622	0.0000
MA(3)	0.479336	0.097863	4.898011	0.0000

R-squared	0.888195	Mean dependent var	11.43920
Adjusted R-squared	0.872058	S.D. dependent var	0.197459
S.E. of regression	0.070629	Akaike info criterion	-2.338684
Sum squared resid	0.483880	Schwarz criterion	-1.974599
Log likelihood	145.9663	Hannan-Quinn criter.	-2.190963
F-statistic	55.04158	Durbin-Watson stat	2.131481
Prob(F-statistic)	0.000000		

Inverted AR Roots	.44		
Inverted MA Roots	.39-.68i	.39+.68i	-.78

Lag Distribution of LOG(JQINDN3361_62_63_OH_KY)	i	Coefficient	Std. Error	t-Statistic
. * |	0	0.12269	0.03724	3.29445
. * |	1	0.08179	0.02483	3.29445
. * |	2	0.04090	0.01241	3.29445
	Sum of Lags	0.24538	0.07448	3.29445

Lag Distribution of LOG(TS_KWH_IND_OH_KY/APGIND_OH_KY)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.17403	0.03034	-5.73555
* . |	1	-0.08701	0.01517	-5.73555
	Sum of	-0.26104	0.04551	-5.73555

MWH SALES – INDUSTRIAL – AEROSPACE PRODUCTS AND PARTS

Dependent Variable: LOG(MWHN3364_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13:17
Sample (adjusted): 1976Q3 2010Q4
Included observations: 138 after adjustments
Convergence achieved after 9 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	10.40620	0.301787	34.48198	0.0000
LOG(TS_KWH_IND_OH_KY/CPI)	-0.077685	0.034073	-2.279933	0.0243
CDDB_OH_KY_65	0.000122	8.06E-06	15.17080	0.0000
@ISPERIOD("1986q2")+@ISPERIOD("1991q4")	0.129654	0.025078	5.170028	0.0000
@ISPERIOD("1991q1")+@ISPERIOD("1999q4")	-0.084145	0.025266	-3.330377	0.0011
@ISPERIOD("1992q1")+@ISPERIOD("2000q3")	-0.280391	0.025243	-11.10777	0.0000
@ISPERIOD("2008q2")+@ISPERIOD("2002q3")	0.164495	0.025305	6.500603	0.0000
@ISPERIOD("2001q2")	0.219082	0.036720	5.966257	0.0000
@ISPERIOD("2001q4")+@ISPERIOD("2004q1")	0.127053	0.026964	4.711866	0.0000
@ISPERIOD("2003q3")	-0.159349	0.037565	-4.241923	0.0000
@ISPERIOD("2003q4")	-0.403937	0.036510	-11.06362	0.0000
PDL01	0.159517	0.055972	2.849946	0.0051
AR(1)	0.475000	0.083613	5.680911	0.0000
AR(2)	0.458309	0.083692	5.476172	0.0000

R-squared	0.922112	Mean dependent var	11.13682
Adjusted R-squared	0.913946	S.D. dependent var	0.144033
S.E. of regression	0.042252	Akaike info criterion	-3.394411
Sum squared resid	0.221367	Schwarz criterion	-3.097443
Log likelihood	248.2144	Hannan-Quinn criter.	-3.273731
F-statistic	112.9252	Durbin-Watson stat	1.928903
Prob(F-statistic)	0.000000		

Inverted AR Roots	.95	-.48

Lag Distribution of LOG(JQINDN3364_OH_KY)	i	Coefficient	Std. Error	t-Statistic
. *|	0	0.15952	0.05597	2.84995
. * |	1	0.07976	0.02799	2.84995
Sum of Lags		0.23928	0.08396	2.84995

MWH SALES – INDUSTRIAL – MISCELLANEOUS

Dependent Variable: LOG(MWHNAOI_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13:16
Sample: 1979Q1 2010Q4
Included observations: 128
Convergence achieved after 8 iterations
MA Backcast: 1978Q3 1978Q4

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	11.88779	0.501920	23.68465	0.0000
LOG(JQINDNAOI_OH_KY)	0.437354	0.202024	2.164859	0.0325
CDDB_OH_KY_65	0.000152	5.82E-06	26.08549	0.0000
D_1965Q1_2001Q3	0.239000	0.034977	6.832993	0.0000
@ISPERIOD("1993q1")+@ISPERIOD("1993q2")	-0.112249	0.022882	-4.905591	0.0000
@ISPERIOD("1996q2")	-0.100633	0.024413	-4.122139	0.0001
@ISPERIOD("2003q4")	-0.064136	0.024469	-2.621110	0.0100
@ISPERIOD("2004q4")	0.131309	0.027091	4.846902	0.0000
@ISPERIOD("2005q1")	-0.166456	0.027212	-6.117062	0.0000
@ISPERIOD("2000q2")	-0.153083	0.029028	-5.273714	0.0000
@ISPERIOD("2000q3")+@ISPERIOD("2000q4")	-0.105271	0.027091	-3.885913	0.0002
@ISPERIOD("2001q2")+@ISPERIOD("2005q4")	-0.069407	0.017390	-3.991301	0.0001
@ISPERIOD("2008q3")+@ISPERIOD("2008q4")	0.133541	0.023910	5.585172	0.0000
PDL01	-0.055260	0.031283	-1.766453	0.0800
AR(1)	0.980983	0.012992	75.50632	0.0000
MA(2)	0.150976	0.000364	414.8660	0.0000

R-squared	0.986800	Mean dependent var	12.43838
Adjusted R-squared	0.985032	S.D. dependent var	0.282311
S.E. of regression	0.034539	Akaike info criterion	-3.776990
Sum squared resid	0.133609	Schwarz criterion	-3.420486
Log likelihood	257.7274	Hannan-Quinn criter.	-3.632141
F-statistic	558.1851	Durbin-Watson stat	1.906248
Prob(F-statistic)	0.000000		

Inverted AR Roots	.98

Lag Distribution of LOG(DS_KWH_IND_OH_KY(-4)/CPI(-4))	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.05526	0.03128	-1.76645
* . |	1	-0.02763	0.01564	-1.76645
Sum of Lags		-0.08289	0.04692	-1.76645

KWH SALES – OTHER PUBLIC AUTHORITIES – WATER PUMPING

Dependent Variable: LOG(KWHOPAWP_OH_KY)
Method: Least Squares
Date: 02/22/11 Time: 17:19
Sample: 1976M01 2010M12
Included observations: 420

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	7.343583	0.815592	9.003991	0.0000
D_1965M01_2001M12*LOG(CUSRES_OH_KY)	0.666205	0.059001	11.29152	0.0000
(1-D_1965M01_2001M12)*LOG(CUSRES_OH_KY)	0.623779	0.058028	10.74957	0.0000
LOG(DS_KW_OPA_OH_KY/CPI)	-0.041952	0.020836	-2.013434	0.0448
((@MONTH=5)+(@MONTH=6)+(@MONTH=7)+(@MONTH=8))*(PRECIP_OH_KY+PRECIP_OH_KY(-1))	-0.003603	0.001357	-2.654939	0.0083
((@MONTH=4)+(@MONTH=9)+(@MONTH=10)+(@MONTH=11))*(PRECIP_OH_KY+PRECIP_OH_KY(-1))	-0.002277	0.001320	-1.725192	0.0853
((@MONTH=6)+(@MONTH=7))*CDD_OH_KY_65	0.000684	5.08E-05	13.47076	0.0000
(@MONTH=8)*CDD_OH_KY_65	0.000774	5.67E-05	13.65227	0.0000
(1-((@MONTH=6)+(@MONTH=7)+(@MONTH=8)))*CDD_OH_KY_65	0.001241	0.000101	12.33444	0.0000
@ISPERIOD("1982m06")	0.832372	0.081478	10.21594	0.0000
@ISPERIOD("1998m10")	-0.559534	0.081309	-6.881549	0.0000
@ISPERIOD("2000m01")	-0.803448	0.081575	-9.849237	0.0000
@ISPERIOD("2000m06")	0.354003	0.081863	4.324362	0.0000
@ISPERIOD("2000m05")	-0.691377	0.082285	-8.402177	0.0000
@ISPERIOD("2000m07")	-1.272906	0.081849	-15.55187	0.0000
D_2000M08_2001M12	-0.485575	0.024621	-19.72236	0.0000
@ISPERIOD("2001m07")	-0.879371	0.084491	-10.40782	0.0000
D_2001M09_2002M06	-0.144578	0.028124	-5.140731	0.0000
D_2002M07_2003M01	0.365595	0.038160	9.580551	0.0000
@ISPERIOD("2002m10")	-0.453355	0.089081	-5.089212	0.0000
@ISPERIOD("2003m01")	0.476502	0.088909	5.359416	0.0000
@ISPERIOD("2004m01")	0.424579	0.081677	5.198297	0.0000
@ISPERIOD("2004m03")	0.833829	0.081677	10.20890	0.0000
@ISPERIOD("2006m09")	-0.530826	0.081833	-6.486693	0.0000
@ISPERIOD("2006m10")	0.298049	0.082239	3.624159	0.0003
@ISPERIOD("2010m03")	0.601023	0.082044	7.325577	0.0000
D_1965M01_2007M09	0.219629	0.017147	12.80855	0.0000

R-squared	0.921765	Mean dependent var	16.43708
Adjusted R-squared	0.916589	S.D. dependent var	0.279638
S.E. of regression	0.080762	Akaike info criterion	-2.132488
Sum squared resid	2.563358	Schwarz criterion	-1.872757
Log likelihood	474.8225	Hannan-Quinn criter.	-2.029831
F-statistic	178.0885	Durbin-Watson stat	1.729098
Prob(F-statistic)	0.000000		

KWH SALES – OTHER PUBLIC AUTHORITIES – LESS WATER PUMPING

Dependent Variable: LOG(KWHOPALWP_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 11:07
Sample: 1978M01 2010M12
Included observations: 396
Convergence achieved after 6 iterations
MA Backcast: 1977M01 1977M12

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	9.177343	0.464818	19.74395	0.0000
LOG(DS_KWH_OPA_OH_KY/CPI)	-0.153704	0.036853	-4.170683	0.0000
LOG(DS_KWH_OPA_OH_KY(-11)/APGOPA_OH_KY(-11))	-0.086142	0.021786	-3.953931	0.0001
CDDB_OH_KY_65*D_1976M01_1984M12	0.000266	0.000101	2.642251	0.0086
CDDB_OH_KY_65*(1-D_1976M01_1984M12)	0.000578	5.45E-05	10.59282	0.0000
HDDB_OH_KY_59*D_1976M01_1984M12	0.000107	3.18E-05	3.358502	0.0009
HDDB_OH_KY_59*(1-D_1976M01_1984M12)	8.33E-05	2.13E-05	3.912876	0.0001
@MONTH=6	0.044197	0.011728	3.768620	0.0002
@MONTH=11	-0.048075	0.011843	-4.059367	0.0001
@ISPERIOD("1994m02")	0.271680	0.053263	5.100765	0.0000
@ISPERIOD("1995m08")	-0.228265	0.053677	-4.252564	0.0000
@ISPERIOD("1999m06")	-0.239280	0.053810	-4.446751	0.0000
@ISPERIOD("1999m10")	0.263578	0.053521	4.924797	0.0000
@ISPERIOD("1999m12")	0.271471	0.054635	4.968812	0.0000
@ISPERIOD("2000m04")	-0.485594	0.054471	-8.914713	0.0000
@ISPERIOD("2000m12")	0.289804	0.060753	4.770228	0.0000
@ISPERIOD("2001m01")	-0.237152	0.059899	-3.959179	0.0001
@ISPERIOD("2001m04")	-0.280704	0.054442	-5.156055	0.0000
@ISPERIOD("2002m12")	-0.196509	0.053360	-3.682695	0.0003
PDL01	0.498819	0.045765	10.89966	0.0000
AR(1)	0.559005	0.044939	12.43909	0.0000
MA(12)	0.211711	0.052362	4.043206	0.0001

R-squared	0.941059	Mean dependent var	18.51108
Adjusted R-squared	0.937750	S.D. dependent var	0.249366
S.E. of regression	0.062217	Akaike info criterion	-2.662435
Sum squared resid	1.447722	Schwarz criterion	-2.441245
Log likelihood	549.1621	Hannan-Quinn criter.	-2.574806
F-statistic	284.3511	Durbin-Watson stat	2.160948
Prob(F-statistic)	0.000000		

Inverted AR Roots	.56			
Inverted MA Roots	.85+.23i	.85-.23i	.62+.62i	.62+.62i
	.23+.85i	.23-.85i	-.23-.85i	-.23+.85i
	-.62+.62i	-.62+.62i	-.85-.23i	-.85+.23i

Lag Distribution of LOG(E90X_OH_KY)	i	Coefficient	Std. Error	t-Statistic
. * |	0	0.74823	0.06865	10.8997
. * |	1	0.49882	0.04576	10.8997
. * |	2	0.24941	0.02288	10.8997
	Sum of Lags	1.49646	0.13729	10.8997

KWH SALES – STREET LIGHTING

Dependent Variable: LOG(KWHSL_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 11:10
Sample (adjusted): 1976M03 2010M12
Included observations: 418 after adjustments
Convergence achieved after 13 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	6.634622	0.817873	8.112046	0.0000
LOG(N_OH_KY)	1.187030	0.093199	12.73652	0.0000
D_1965M01_2002M12*@MONTH=1	0.129729	0.005804	22.34983	0.0000
D_1965M01_2002M12*@MONTH=2	-0.017364	0.005586	-3.108402	0.0020
D_1965M01_2002M12*@MONTH=4	-0.125481	0.005380	-23.32294	0.0000
D_1965M01_2002M12*@MONTH=5	-0.183103	0.005853	-31.28516	0.0000
D_1965M01_2002M12*@MONTH=6	-0.272574	0.006585	-41.39356	0.0000
D_1965M01_2002M12*@MONTH=7	-0.227443	0.006769	-33.60018	0.0000
D_1965M01_2002M12*@MONTH=8	-0.144261	0.006805	-21.19983	0.0000
D_1965M01_2002M12*@MONTH=9	-0.079487	0.006838	-11.62400	0.0000
D_1965M01_2002M12*@MONTH=10	0.026083	0.006776	3.849203	0.0001
D_1965M01_2002M12*@MONTH=11	0.080469	0.006638	12.12199	0.0000
D_1965M01_2002M12*@MONTH=12	0.143832	0.006298	22.83764	0.0000
@ISPERIOD("1980m02")	-0.163252	0.022107	-7.384568	0.0000
@ISPERIOD("1991m06")	-0.366945	0.023674	-15.49977	0.0000
@ISPERIOD("1999m06")	0.526448	0.022075	23.84800	0.0000
@ISPERIOD("1999m11")	-0.215151	0.022062	-9.752211	0.0000
@ISPERIOD("2001m02")	-0.751729	0.022988	-32.70043	0.0000
@ISPERIOD("2001m03")	0.419849	0.023222	18.08003	0.0000
@ISPERIOD("2001m05")	-0.314116	0.022717	-13.82746	0.0000
@ISPERIOD("2001m07")+@ISPERIOD("2002m07")	0.194966	0.016484	11.82759	0.0000
@ISPERIOD("2002m06")	-0.146027	0.022475	-6.497423	0.0000
@ISPERIOD("1991m03")	-0.137568	0.022208	-6.194428	0.0000
@ISPERIOD("2007m02")	-0.134596	0.021717	-6.197862	0.0000
@ISPERIOD("2007m05")	-0.106050	0.022853	-4.640490	0.0000
@ISPERIOD("2007m06")	0.054432	0.022445	2.425113	0.0158
@ISPERIOD("2002m02")	0.106135	0.022361	4.746497	0.0000
@ISPERIOD("2006m02")	0.084365	0.021746	3.879554	0.0001
D_1965M01_2007M09	0.067105	0.012236	5.484119	0.0000
PDL01	-0.148257	0.052585	-2.819371	0.0051
AR(1)	0.411845	0.055537	7.415701	0.0000
AR(2)	0.220771	0.053764	4.106317	0.0000

R-squared	0.978873	Mean dependent var	15.94102
Adjusted R-squared	0.977176	S.D. dependent var	0.157949
S.E. of regression	0.023862	Akaike info criterion	-4.559575
Sum squared resid	0.219790	Schwarz criterion	-4.250639
Log likelihood	984.9512	Hannan-Quinn criter.	-4.437446
F-statistic	576.9154	Durbin-Watson stat	2.042699
Prob(F-statistic)	0.000000		

Inverted AR Roots	.72	-.31

Lag Distribution of LOG(SAT_SL_OH_KY)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.19768	0.07011	-2.81937
* . |	1	-0.14826	0.05259	-2.81937
* . |	2	-0.09884	0.03506	-2.81937
* . |	3	-0.04942	0.01753	-2.81937
	Sum of Lags	-0.49419	0.17528	-2.81937

SERVICE AREA – SUMMER PEAK

Dependent Variable: LOG(MWSPEAK_OH_KY)
Method: Least Squares
Date: 03/02/11 Time: 17:36
Sample: 1/01/1974 12/31/2010 IF WEEKDAY<=5
Included observations: 374

Variable	Coefficient	Std. Error	t-Statistic	Prob.
D_072180_091498*MJUN	-3.011771	0.321205	-9.376481	0.0000
(1-D_072180_091498)*MJUN	-3.124540	0.319518	-9.778925	0.0000
D_072180_091498*MJUL	-3.287855	0.290345	-11.32395	0.0000
(1-D_072180_091498)*MJUL	-3.623843	0.184254	-19.66766	0.0000
D_072180_091498*MAUG	-1.598406	0.243600	-6.561600	0.0000
(1-D_072180_091498)*MAUG	-4.460045	0.229457	-19.43742	0.0000
MSEP	-3.635690	0.260506	-13.95628	0.0000
(D_072180_091498)*(MJUN+MSEP)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.909660	0.018172	50.05902	0.0000
(1-D_072180_091498)*(MJUN+MSEP)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.920730	0.017986	51.19140	0.0000
(D_072180_091498)*(MJUL)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.915842	0.024645	37.16087	0.0000
(1-D_072180_091498)*(MJUL)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.943693	0.013466	70.08135	0.0000
(D_072180_091498)*(MAUG)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.749686	0.020357	36.82746	0.0000
(1-D_072180_091498)*(MAUG)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	1.007129	0.018754	53.70340	0.0000
(MJUN)*PMHIGH	0.006528	0.002595	2.516140	0.0123
(MJUL+MAUG+MSEP)*PMHIGH	0.010185	0.001090	9.341020	0.0000
(MJUN+MJUL+MAUG+MSEP)*PREVPMHIGH	0.002587	0.000596	4.339495	0.0000
(MJUN+MAUG)*AMLOW	0.005175	0.000788	6.569148	0.0000
MJUL*AMLOW	0.003140	0.000945	3.322639	0.0010
MSEP*AMLOW	0.009130	0.002129	4.288536	0.0000
(MJUN+MJUL+MAUG+MSEP)*PMHUMIDATHIGH	0.000754	0.000302	2.497370	0.0130
JULY4WEEK*PMHIGH	-0.000318	7.53E-05	-4.226065	0.0000
@ISPERIOD("6/11/1976")	-0.097349	0.036540	-2.664175	0.0081
@ISPERIOD("6/18/1976")	-0.124767	0.036541	-3.414419	0.0007
@ISPERIOD("7/5/1993")	-0.109721	0.035655	-3.077264	0.0023
@ISPERIOD("7/5/99")	-0.122669	0.035685	-3.437554	0.0007
@ISPERIOD("8/13/1999")	0.105063	0.035423	2.965939	0.0032
@ISPERIOD("8/17/1999")	0.104280	0.035654	2.924797	0.0037
D_080107_082907	-0.093970	0.010804	-8.697776	0.0000
@ISPERIOD("7/7/10")	-0.384991	0.035580	-10.82035	0.0000

R-squared	0.980720	Mean dependent var	8.264019
Adjusted R-squared	0.979155	S.D. dependent var	0.240056
S.E. of regression	0.034659	Akaike info criterion	-3.812170
Sum squared resid	0.414422	Schwarz criterion	-3.507882
Log likelihood	741.8757	Hannan-Quinn criter.	-3.691354
Durbin-Watson stat	0.689958		

SERVICE AREA – WINTER PEAK

Dependent Variable: LOG(MWWPEAK_OH_KY)
Method: Least Squares
Date: 03/03/11 Time: 12:36
Sample: 1/01/1974 12/31/2010 IF WEEKDAY<=5
Included observations: 258

Variable	Coefficient	Std. Error	t-Statistic	Prob.
AMPEAK*(MDEC+MJAN+MFEB+MMAR)	-1.609170	0.284221	-5.661692	0.0000
AMPEAK*(MDEC+MJAN+MFEB+MMAR)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.882089	0.025989	33.94138	0.0000
AMPEAK*(MDEC+MJAN+MFEB+MMAR)*AMLOW	-0.002167	0.001165	-1.859507	0.0641
AMPEAK*(MDEC+MJAN+MMAR)*WINDAM	0.006007	0.001457	4.122567	0.0001
AMPEAK*(MJAN+MFEB+MMAR)*PREVPMLOW	-0.002277	0.001045	-2.178155	0.0303
PMPEAK*(MDEC+MJAN+MFEB+MMAR)	-0.936795	0.372091	-2.517650	0.0125
PMPEAK*(MDEC+MMAR)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.826439	0.034517	23.94265	0.0000
PMPEAK*(MJAN+MFEB)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.822818	0.034252	24.02242	0.0000
PMPEAK*(MDEC+MJAN+MFEB+MMAR)*PMLOW	-0.003700	0.001386	-2.669020	0.0081
@ISPERIOD("1/27/1977")+@ISPERIOD("1/28/1977")	-0.253712	0.058986	-4.301214	0.0000
PMPEAK*XMAS	-0.083042	0.029656	-2.800147	0.0055
@ISPERIOD("1/23/2003")	-0.165564	0.085684	-1.932259	0.0545

R-squared	0.883007	Mean dependent var	8.026330
Adjusted R-squared	0.877776	S.D. dependent var	0.235440
S.E. of regression	0.082311	Akaike info criterion	-2.111221
Sum squared resid	1.666687	Schwarz criterion	-1.945968
Log likelihood	284.3476	Hannan-Quinn criter.	-2.044772
Durbin-Watson stat	0.565187		

6. FORECASTED DEMAND AND ENERGY

On the following pages, the loads for Duke Energy Kentucky are provided. Forecast data is provided before and after the incremental impacts of EE programs. The term "Internal" refers to a forecast without the impacts of either EE or DR removed. The term "Native" refers to the Internal forecast with the DR removed.

a. Service Area Energy Forecasts

Figure B-1 contains the energy forecast for Duke Energy Kentucky's service area.

Before implementation of any new EE programs or incremental EE impacts, Residential use for the twenty-year period of the forecast is expected to increase an average of 1.1 percent per year; Commercial use, 0.9 percent per year; and Industrial use, 1.3 percent per year. The summation of the forecast across each sector and including losses results in a growth rate forecast of 1.0 percent for Net Energy for Load. Plant Auxiliary Use is added to Net Energy for Load for the Total Energy column on the forms.

After implementation of any planned new EE programs and any incremental EE impacts (Figure B-2) Residential use is expected to increase an average of 0.6 percent per year; Commercial use, 0.6 percent per year; and Industrial use, 0.9 percent per year. The summation of the forecast across each sector and including losses results in an after EE growth rate forecast of 0.6 percent for Net Energy for Load.

b. System Seasonal Peak Load Forecast

Figure B-3 contains the forecast of summer and winter peaks for the Duke Energy Kentucky service area. As state earlier, the difference between native and internal load before EE reflects the impact of controllable loads (see Section 6c).

Figure B-4, labeled "Internal Load", summarizes historical and projected growth of the internal peak before implementation of EE programs. The table shows the Summer and succeeding Winter Peaks, the Summer Peaks being the predominant ones historically. Projected growth in the summer peak demand is 0.9 percent. Projected growth in the winter peak demand is 0.8 percent.

Peak load forecasts after implementation of EE programs (Figure B-5 and Figure B-6) are shown for native and internal loads after EE. Based on Figure B-6, the projected growth in the summer peak is 0.7 percent. Projected growth in winter peak demand is 0.6 percent.

c. Controllable Loads

The native peak load forecast reflects the MW impacts from the PowerShare® demand response program and controllable loads from the Power Manager program. The amount of load controlled depends upon the level of operation of the particular customers participating in the programs. The difference between the internal and native peak loads consists of the impact from these controllable loads. See Chapter 4 for a complete discussion of the impacts of DR programs.

d. Load Factor

The numbers below represent the annual percentage load factor for the Duke Energy Kentucky System before any new or incremental EE. It shows the relationship between Net Energy for Load, Figure B-1, and the annual peak, Figure B-4, before EE.

Year	Load Factor
2006	52.2%
2007	53.8%
2008	56.2%
2009	56.8%
2010	53.9%
2011	54.4%
2012	54.5%
2013	54.9%
2014	55.2%
2015	55.4%
2016	55.7%
2017	55.6%
2018	55.6%
2019	55.6%
2020	55.6%
2021	55.5%
2022	55.5%
2023	55.5%
2024	55.4%
2025	55.4%
2026	55.4%
2027	55.4%
2028	55.3%
2029	55.3%
2030	55.3%
2031	55.2%

e. Range of Forecasts

Under the assumption of normal weather, the most likely forecast of electrical energy demand and peak loads is generated using forecasts of economic variables. Moody's Analytics provides the base economic forecast used to prepare the most likely energy demand and peak load forecasts.

In generating the high and low forecasts, Duke Energy Kentucky used the standard errors of the regression from the econometric models used to produce the base energy forecast. The bands are based on an 95% confidence interval (from 2.5% to 97.5%) around the forecast which equates to 1.96 standard deviations. These calculations were used to adjust the base forecast up or down, thus providing high and low bands around the most likely forecast.

In general, the upper band reflects relatively optimistic assumptions about the future growth of Duke Energy Kentucky sales while the lower band depicts the impact of a pessimistic scenario.

Figure B-7 provides the high, low, and most likely before EE forecasts of electric energy and peak demand for the service area. Figure B-8 provides similar information after implementation of the EE programs.

f. Monthly Forecast

Figures B-9 through Figure B-12 contain the net monthly energy forecast, the net monthly internal peak load forecast, and the energy forecast by customer class for the total Duke Energy Kentucky system before and after EE.

FIGURE B-1 PART 1

DUKE ENERGY KENTUCKY SYSTEM

SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)

BEFORE EE

		(1)	(2)	(3)	(4)	(5)	(6)
	YEAR	RURAL AND RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET-HWY LIGHTING	SALES FOR RESALE a	OTHER
-5	2006	1,404,458	1,371,330	781,003	17,338	0	308,384
-4	2007	1,534,340	1,460,428	806,736	15,988	0	321,236
-3	2008	1,472,417	1,443,873	800,769	16,001	0	315,259
-2	2009	1,410,347	1,395,345	730,917	15,348	0	301,793
-1	2010	1,550,929	1,451,523	782,132	15,167	0	313,648
0	2011	1,470,777	1,445,145	794,032	15,127	0	292,847
1	2012	1,482,396	1,482,020	817,908	15,332	0	287,923
2	2013	1,483,095	1,540,393	838,556	15,428	0	300,208
3	2014	1,498,975	1,600,749	853,676	15,517	0	308,775
4	2015	1,516,495	1,630,498	865,907	15,617	0	313,042
5	2016	1,518,021	1,644,907	877,028	15,719	0	314,062
6	2017	1,530,689	1,653,531	887,774	15,828	0	313,324
7	2018	1,544,284	1,660,095	898,114	15,945	0	312,029
8	2019	1,560,640	1,665,809	908,536	16,059	0	310,637
9	2020	1,577,872	1,672,953	918,487	16,173	0	309,245
10	2021	1,595,920	1,680,285	928,476	16,284	0	308,169
11	2022	1,614,990	1,686,488	938,298	16,396	0	306,735
12	2023	1,637,121	1,690,017	947,776	16,512	0	305,413
13	2024	1,652,403	1,692,597	956,987	16,626	0	302,172
14	2025	1,669,580	1,696,206	966,427	16,743	0	299,008
15	2026	1,689,808	1,701,241	975,526	16,861	0	295,904
16	2027	1,711,578	1,707,781	984,756	16,977	0	293,122
17	2028	1,737,450	1,716,160	994,631	17,096	0	290,749
18	2029	1,760,823	1,724,206	1,003,824	17,217	0	288,750
19	2030	1,785,972	1,731,259	1,013,069	17,338	0	286,856
20	2031	1,815,677	1,741,816	1,023,054	17,459	0	285,117

(a) Sales for resale to municipals.

FIGURE B-1 PART 2
DUKE ENERGY KENTUCKY SYSTEM

SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)

BEFORE EE

	YEAR	(7) (1+2+3 +4+5+6) TOTAL CONSUMPTION	(8) LOSSES AND UNACCOUNTED FOR b	(9) (7+8) NET ENERGY FOR LOAD
	----	-----------	-----------	----------
-5	2006	3,882,513	158,557	4,041,070
-4	2007	4,138,727	200,515	4,339,242
-3	2008	4,048,319	185,386	4,233,705
-2	2009	3,853,751	162,419	4,016,171
-1	2010	4,113,400	133,325	4,246,725
0	2011	4,017,929	206,584	4,224,513
1	2012	4,085,579	210,043	4,295,622
2	2013	4,177,679	214,866	4,392,545
3	2014	4,277,692	220,118	4,497,810
4	2015	4,341,558	223,514	4,565,072
5	2016	4,369,738	225,000	4,594,738
6	2017	4,401,146	226,725	4,627,871
7	2018	4,430,467	228,328	4,658,795
8	2019	4,461,681	230,033	4,691,714
9	2020	4,494,729	231,814	4,726,543
10	2021	4,529,134	233,703	4,762,837
11	2022	4,562,907	235,542	4,798,449
12	2023	4,596,839	237,389	4,834,228
13	2024	4,620,784	238,657	4,859,441
14	2025	4,647,964	240,143	4,888,107
15	2026	4,679,341	241,824	4,921,165
16	2027	4,714,213	243,681	4,957,894
17	2028	4,756,086	245,873	5,001,959
18	2029	4,794,820	247,970	5,042,790
19	2030	4,834,494	250,084	5,084,578
20	2031	4,883,122	252,661	5,135,783

(b) Transmission, transformer and other losses and energy unaccounted for.

FIGURE B-2 PART 1

DUKE ENERGY KENTUCKY SYSTEM

SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR) a

AFTER EE

		(1)	(2)	(3)	(4)	(5)	(6)
	YEAR	RURAL AND RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET-HWY LIGHTING	SALES FOR RESALE b	OTHER
-5	2006	1,404,458	1,371,330	781,003	17,338	0	308,384
-4	2007	1,534,340	1,460,428	806,736	15,988	0	321,236
-3	2008	1,472,417	1,443,873	800,769	16,001	0	315,259
-2	2009	1,410,347	1,395,345	730,917	15,348	0	301,793
-1	2010	1,550,929	1,451,523	782,132	15,167	0	313,648
0	2011	1,468,766	1,443,695	792,858	15,127	0	292,544
1	2012	1,474,821	1,477,026	813,959	15,332	0	286,900
2	2013	1,468,557	1,530,786	831,244	15,428	0	298,213
3	2014	1,477,126	1,585,755	842,682	15,517	0	305,665
4	2015	1,486,599	1,609,465	850,750	15,617	0	308,678
5	2016	1,482,387	1,611,626	853,239	15,719	0	307,216
6	2017	1,487,852	1,614,111	859,721	15,828	0	305,266
7	2018	1,494,041	1,614,624	865,857	15,945	0	302,801
8	2019	1,502,796	1,614,374	872,142	16,059	0	300,277
9	2020	1,512,239	1,615,593	878,043	16,173	0	297,791
10	2021	1,522,375	1,617,063	884,057	16,284	0	295,657
11	2022	1,533,281	1,617,506	889,974	16,396	0	293,221
12	2023	1,546,947	1,615,472	895,624	16,512	0	290,929
13	2024	1,553,387	1,612,661	901,113	16,626	0	286,776
14	2025	1,561,563	1,610,964	906,929	16,743	0	282,745
15	2026	1,572,406	1,610,832	912,562	16,861	0	278,830
16	2027	1,584,537	1,612,290	918,459	16,977	0	275,271
17	2028	1,600,331	1,615,748	925,207	17,096	0	272,161
18	2029	1,613,632	1,618,914	931,305	17,217	0	269,428
19	2030	1,628,311	1,621,279	937,576	17,338	0	266,832
20	2031	1,653,911	1,631,755	947,917	17,459	0	265,264

(a) Includes EE Impacts.

(b) Sales for resale to municipals.

FIGURE B-2 PART 2

DUKE ENERGY KENTUCKY SYSTEM

SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR) c

AFTER EE

	YEAR	(7) (1+2+3 +4+5+6) **TOTAL CONSUMPTION**	(8) **LOSSES AND UNACCOUNTED FOR d**	(9) (7+8) **NET ENERGY FOR LOAD**
	----	-----------	-----------	----------
-5	2006	3,882,513	158,557	4,041,070
-4	2007	4,138,727	200,515	4,339,242
-3	2008	4,048,319	185,386	4,233,705
-2	2009	3,853,751	162,419	4,016,170
-1	2010	4,113,400	133,325	4,246,725
0	2011	4,012,990	206,312	4,219,302
1	2012	4,068,039	209,106	4,277,145
2	2013	4,144,228	213,103	4,357,331
3	2014	4,226,745	217,444	4,444,190
4	2015	4,271,109	219,825	4,490,934
5	2016	4,270,187	219,801	4,489,989
6	2017	4,282,778	220,523	4,503,301
7	2018	4,293,268	221,138	4,514,406
8	2019	4,305,648	221,858	4,527,506
9	2020	4,319,840	222,676	4,542,515
10	2021	4,335,436	223,553	4,558,989
11	2022	4,350,379	224,401	4,574,780
12	2023	4,365,484	225,255	4,590,739
13	2024	4,370,564	225,570	4,596,134
14	2025	4,378,943	226,035	4,604,978
15	2026	4,391,491	226,724	4,618,216
16	2027	4,407,535	227,590	4,635,125
17	2028	4,430,543	228,827	4,659,370
18	2029	4,450,495	229,884	4,680,379
19	2030	4,471,335	231,011	4,702,346
20	2031	4,516,306	233,396	4,749,702

(c) Includes EE Impacts

(d) Transmission, transformer and other losses and energy unaccounted for.

FIGURE B-3

DUKE ENERGY KENTUCKY SYSTEM

SEASONAL PEAK LOAD FORECAST (MEGAWATTS)

BEFORE EE

NATIVE LOAD a

		SUMMER			WINTER d		
	YEAR	LOAD	CHANGE b	PERCENT CHANGE c	LOAD	CHANGE b	PERCENT CHANGE c
-5	2006	881			738		
-4	2007	912	31	3.5	725	-13	-1.8
-3	2008	853	-59	-6.5	768	43	6.0
-2	2009	808	-45	-5.3	671	-97	-12.6
-1	2010	892	84	10.4	689	18	2.7
0	2011	855	-37	-4.1	718	29	4.2
1	2012	868	13	1.5	730	12	1.7
2	2013	878	10	1.2	741	11	1.5
3	2014	893	15	1.7	749	8	1.1
4	2015	901	8	0.9	751	2	0.3
5	2016	901	0	0.0	757	6	0.8
6	2017	909	8	0.9	760	3	0.4
7	2018	916	7	0.8	766	6	0.8
8	2019	923	7	0.8	770	4	0.5
9	2020	931	8	0.9	776	6	0.8
10	2021	939	8	0.9	781	5	0.6
11	2022	946	7	0.7	786	5	0.6
12	2023	955	9	1.0	790	4	0.5
13	2024	961	6	0.6	795	5	0.6
14	2025	967	6	0.6	800	5	0.6
15	2026	974	7	0.7	806	6	0.7
16	2027	982	8	0.8	813	7	0.9
17	2028	992	10	1.0	820	7	0.9
18	2029	1,001	9	0.9	826	6	0.7
19	2030	1,010	9	0.9	834	8	1.0
20	2031	1,021	11	1.1	843	9	1.1

(a) Excludes controllable load.
(b) Difference betw een reporting year and previous year.
(c) Difference expressed as a percent of previous year.
(d) Winter load reference is to peak loads w hich occur in the follow ing w inter.

FIGURE B-4

DUKE ENERGY KENTUCKY SYSTEM

SEASONAL PEAK LOAD FORECAST (MEGAWATTS)

BEFORE DSM

INTERNAL LOAD a

		SUMMER			WINTER d		
	YEAR	LOAD	CHANGE b	PERCENT CHANGE c	LOAD	CHANGE b	PERCENT CHANGE c
-5	2006	883			738		
-4	2007	921	38	4.3	725	-13	-1.8
-3	2008	860	-61	-6.6	768	43	6.0
-2	2009	808	-52	-6.1	671	-97	-12.6
-1	2010	899	91	11.3	689	18	2.7
0	2011	886	-13	-1.4	736	47	6.8
1	2012	900	14	1.6	749	13	1.8
2	2013	913	13	1.4	762	13	1.7
3	2014	930	17	1.9	772	10	1.3
4	2015	940	10	1.1	776	4	0.5
5	2016	941	1	0.1	782	6	0.8
6	2017	949	8	0.8	785	3	0.4
7	2018	956	7	0.7	791	6	0.8
8	2019	963	7	0.7	795	4	0.5
9	2020	971	8	0.8	801	6	0.8
10	2021	979	8	0.8	806	5	0.6
11	2022	987	8	0.8	811	5	0.6
12	2023	995	8	0.8	815	4	0.5
13	2024	1,001	6	0.6	820	5	0.6
14	2025	1,007	6	0.6	825	5	0.6
15	2026	1,014	7	0.7	831	6	0.7
16	2027	1,023	9	0.9	838	7	0.8
17	2028	1,032	9	0.9	845	7	0.8
18	2029	1,041	9	0.9	851	6	0.7
19	2030	1,050	9	0.9	859	8	0.9
20	2031	1,061	11	1.0	868	9	1.0

(a) Excludes controllable load.
(b) Difference between reporting year and previous year.
(c) Difference expressed as a percent of previous year.
(d) Winter load reference is to peak loads which occur in the following winter.

FIGURE B-5

DUKE ENERGY KENTUCKY SYSTEM

SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a

AFTER EE

NATIVE LOAD b

		SUMMER			WINTER e		
	YEAR	LOAD	CHANGE c	PERCENT CHANGE d	LOAD	CHANGE c	PERCENT CHANGE d
-5	2006	811			665		
-4	2007	814	3	0.4	674	10	1.5
-3	2008	892	77	9.5	692	17	2.6
-2	2009	881	-11	-1.2	738	46	6.6
-1	2010	911	30	3.4	725	-13	-1.7
0	2011	855	-56	-6.1	717	-8	-1.1
1	2012	866	11	1.3	728	11	1.5
2	2013	875	9	1.0	737	9	1.2
3	2014	887	12	1.4	743	6	0.8
4	2015	893	6	0.7	743	0	0.0
5	2016	891	-2	-0.2	747	4	0.5
6	2017	897	6	0.7	749	2	0.3
7	2018	901	4	0.4	753	4	0.5
8	2019	906	5	0.6	756	3	0.4
9	2020	912	6	0.7	760	4	0.5
10	2021	918	6	0.7	763	3	0.4
11	2022	924	6	0.7	767	4	0.5
12	2023	930	6	0.6	769	2	0.3
13	2024	933	3	0.3	772	3	0.4
14	2025	937	4	0.4	776	4	0.5
15	2026	943	6	0.6	780	4	0.5
16	2027	949	6	0.6	785	5	0.6
17	2028	957	8	0.8	790	5	0.6
18	2029	963	6	0.6	795	5	0.6
19	2030	970	7	0.7	803	8	1.0
20	2031	981	11	1.1	811	8	1.0

(a) Includes EE Impacts.
(b) Includes controllable load.
(c) Difference betw een reporting year and previous year.
(d) Difference expressed as a percent of previous year.
(e) Winter load reference is to peak loads w hich occur in the follow ing w inter.

FIGURE B-6

DUKE ENERGY KENTUCKY SYSTEM

SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a

AFTER EE

INTERNAL LOAD b

		SUMMER			WINTER e		
	YEAR	**LOAD**	**CHANGE c**	**PERCENT CHANGE d**	**LOAD**	**CHANGE c**	**PERCENT CHANGE d**
-5	2006	811			665		
-4	2007	817	6	0.8	674	10	1.5
-3	2008	905	87	10.7	692	17	2.6
-2	2009	881	-24	-2.6	738	46	6.6
-1	2010	930	49	5.6	725	-13	-1.7
0	2011	886	-44	-4.7	735	10	1.4
1	2012	898	12	1.4	746	11	1.5
2	2013	910	12	1.3	758	12	1.6
3	2014	925	15	1.6	766	8	1.1
4	2015	933	8	0.9	768	2	0.3
5	2016	931	-2	-0.2	772	4	0.5
6	2017	937	6	0.6	774	2	0.3
7	2018	941	4	0.4	778	4	0.5
8	2019	946	5	0.5	781	3	0.4
9	2020	952	6	0.6	785	4	0.5
10	2021	958	6	0.6	788	3	0.4
11	2022	964	6	0.6	792	4	0.5
12	2023	970	6	0.6	794	2	0.3
13	2024	974	4	0.4	797	3	0.4
14	2025	978	4	0.4	801	4	0.5
15	2026	983	5	0.5	805	4	0.5
16	2027	989	6	0.6	810	5	0.6
17	2028	997	8	0.8	815	5	0.6
18	2029	1,003	6	0.6	820	5	0.6
19	2030	1,010	7	0.7	828	8	1.0
20	2031	1,021	11	1.1	836	8	1.0

(a) Includes EE Impacts.
(b) Excludes controllable load.
(c) Difference between reporting year and previous year.
(d) Difference expressed as a percent of previous year.
(e) Winter load reference is to peak loads which occur in the following winter.

FIGURE B-7

DUKE ENERGY KENTUCKY SYSTEM

RANGE OF FORECASTS
ECONOMIC BANDS

BEFORE EE

	ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD)			PEAK LOAD FORECAST (MW) INTERNAL a		
YEAR	LOW	MOST LIKELY	HIGH	LOW	MOST LIKELY	HIGH
2011	3,942	4,225	4,508	827	886	944
2012	3,969	4,296	4,622	832	900	968
2013	4,035	4,393	4,750	838	913	988
2014	4,115	4,498	4,881	850	930	1,010
2015	4,164	4,565	4,966	856	940	1,024
2016	4,182	4,595	5,008	855	941	1,028
2017	4,205	4,628	5,051	860	949	1,038
2018	4,227	4,659	5,091	865	956	1,047
2019	4,251	4,692	5,132	870	963	1,056
2020	4,278	4,727	5,175	876	971	1,066
2021	4,307	4,763	5,219	882	979	1,075
2022	4,336	4,798	5,261	889	987	1,085
2023	4,365	4,834	5,303	896	995	1,095
2024	4,384	4,859	5,335	900	1,001	1,102
2025	4,406	4,888	5,370	905	1,007	1,109
2026	4,433	4,921	5,410	910	1,014	1,118
2027	4,462	4,958	5,453	917	1,023	1,129
2028	4,499	5,002	5,505	925	1,032	1,140
2029	4,532	5,043	5,554	932	1,041	1,150
2030	4,566	5,085	5,603	939	1,050	1,161
2031	4,609	5,136	5,663	948	1,061	1,173

(a) Excludes controllable load.

FIGURE B-8

DUKE ENERGY KENTUCKY SYSTEM

RANGE OF FORECASTS a
ECONOMIC BANDS

AFTER EE

	ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD)			PEAK LOAD FORECAST (MW) NATIVE b		
YEAR	LOW	MOST LIKELY	HIGH	LOW	MOST LIKELY	HIGH
2011	3,936	4,219	4,502	827	886	944
2012	3,950	4,277	4,604	830	898	966
2013	4,000	4,357	4,715	835	910	985
2014	4,061	4,444	4,828	845	925	1,005
2015	4,090	4,491	4,892	849	933	1,017
2016	4,077	4,490	4,903	845	931	1,018
2017	4,080	4,504	4,927	848	937	1,026
2018	4,083	4,515	4,947	850	941	1,032
2019	4,088	4,528	4,968	853	946	1,039
2020	4,095	4,543	4,991	857	952	1,047
2021	4,104	4,559	5,015	861	958	1,054
2022	4,112	4,575	5,038	866	964	1,062
2023	4,122	4,591	5,060	871	970	1,070
2024	4,121	4,597	5,072	873	974	1,075
2025	4,124	4,606	5,087	876	978	1,080
2026	4,130	4,619	5,107	879	983	1,087
2027	4,140	4,636	5,131	883	989	1,095
2028	4,157	4,660	5,163	890	997	1,105
2029	4,170	4,681	5,192	894	1,003	1,112
2030	4,185	4,703	5,221	899	1,010	1,121
2031	4,224	4,751	5,227	908	1,021	1,133

(a) Includes EE Impacts.

(b) Includes controllable load.

FIGURE B-9 Part 1

DUKE ENERGY KENTUCKY SYSTEM

NET MONTHLY ENERGY FORECAST (MEGAWATT HOURS)

BEFORE EE

YEAR 0	2011	KENTUCKY
January		389,723
February		342,706
March		335,139
April		302,679
May		318,127
June		369,758
July		407,110
August		414,493
September		349,004
October		318,326
November		310,703
December		366,745
YEAR 1	2012	
January		398,401
February		347,324
March		341,938
April		308,631
May		322,895
June		376,521
July		414,068
August		422,015
September		353,091
October		323,297
November		315,562
December		371,879

FIGURE B-9 Part 2

DUKE ENERGY KENTUCKY SYSTEM

NET MONTHLY INTERNAL PEAK LOAD FORECAST (MEGAWATTS)

BEFORE EE

YEAR 0	2011	KENTUCKY
January		759
February		709
March		668
April		606
May		677
June		831
July		871
August		871
September		782
October		598
November		673
December		731

YEAR 1	2012	
January		767
February		716
March		675
April		613
May		684
June		840
July		880
August		880
September		790
October		604
November		680
December		739

FIGURE B-10 Part 1

DUKE ENERGY KENTUCKY SYSTEM

NET MONTHLY ENERGY FORECAST (MEGAWATT HOURS) a

AFTER EE

YEAR 0	2011	KENTUCKY
January		389,656
February		342,587
March		334,943
April		302,432
May		317,779
June		369,342
July		406,611
August		413,914
September		348,392
October		317,687
November		310,008
December		365,950

YEAR 1	2012	
January		397,433
February		346,321
March		340,793
April		307,506
May		321,546
June		374,948
July		412,277
August		420,104
September		351,272
October		321,729
November		313,633
December		369,582

(a) Includes EE impacts.

FIGURE B-10 Part 2

DUKE ENERGY KENTUCKY SYSTEM

NET MONTHLY INTERNAL PEAK LOAD FORECAST (MEGAWATTS) a

AFTER EE

YEAR 0	2011	KENTUCKY
January		759
February		709
March		668
April		606
May		677
June		830
July		870
August		870
September		781
October		597
November		672
December		730
YEAR 1	2012	
January		766
February		715
March		674
April		612
May		682
June		838
July		878
August		878
September		788
October		602
November		678
December		737

(a) Includes EE impacts.

FIGURE B-11 PART 1

DUKE ENERGY KENTUCKY SYSTEM

SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)

BEFORE EE

		(1)	(2)	(3)	(4)	(5)	(6)
YEAR 0	2011	RURAL AND RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET-HWY LIGHTING	SALES FOR RESALE a	OTHER
--------		-----------	----------	----------	----------	---------	-----
January		158,243	123,749	66,538	1,261	0	24,762
February		140,286	113,166	62,520	1,261	0	23,112
March		122,859	111,630	64,568	1,275	0	23,469
April		100,391	109,655	62,973	1,260	0	22,726
May		88,249	111,107	64,766	1,253	0	23,377
June		112,908	127,705	67,768	1,271	0	25,907
July		142,230	135,895	69,563	1,257	0	26,383
August		148,649	136,455	71,390	1,263	0	26,572
September		132,726	131,722	69,597	1,259	0	26,923
October		97,434	114,856	66,037	1,255	0	23,937
November		93,775	108,243	63,378	1,251	0	22,042
December		133,027	120,961	64,934	1,261	0	23,637
YEAR 1	2012						

January		160,501	126,906	68,657	1,278	0	24,514
February		142,104	116,055	64,483	1,278	0	22,872
March		124,398	114,479	66,558	1,293	0	23,205
April		101,524	112,455	64,883	1,277	0	22,391
May		89,247	113,943	66,681	1,270	0	23,019
June		114,058	130,963	69,772	1,288	0	25,418
July		143,306	139,361	71,620	1,274	0	25,909
August		149,519	139,935	73,502	1,280	0	26,103
September		133,226	135,081	71,655	1,276	0	26,384
October		97,439	117,788	67,990	1,272	0	23,450
November		93,987	111,007	65,253	1,268	0	21,532
December		133,086	124,048	66,854	1,278	0	23,126

(a) Sales for resale to municipals.

FIGURE B-11 PART 2

DUKE ENERGY KENTUCKY SYSTEM

SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)

BEFORE EE

YEAR 0	2011	(7) (1+2+3 +4+5+6) **TOTAL CONSUMPTION**	(8) **LOSSES AND UNACCOUNTED FOR b**	(9) (7+8) **NET ENERGY FOR LOAD**
--------		-----------	-----------	----------
January		374,554	15,169	389,723
February		340,346	2,360	342,706
March		323,801	11,338	335,139
April		297,005	5,674	302,679
May		288,752	29,375	318,127
June		335,559	34,199	369,758
July		375,328	31,782	407,110
August		384,329	30,164	414,493
September		362,227	(13,223)	349,004
October		303,519	14,807	318,326
November		288,689	22,014	310,703
December		343,820	22,925	366,745
YEAR 1	2012			

January		381,856	16,545	398,401
February		346,791	533	347,324
March		329,932	12,006	341,938
April		302,530	6,101	308,631
May		294,160	28,735	322,895
June		341,499	35,022	376,521
July		381,471	32,597	414,068
August		390,339	31,676	422,015
September		367,622	(14,531)	353,091
October		307,940	15,357	323,297
November		293,047	22,515	315,562
December		348,392	23,487	371,879

(b) Transmission, transformer and other losses and energy unaccounted for.

FIGURE B-12 PART 1

DUKE ENERGY KENTUCKY SYSTEM

SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR) a

AFTER EE

YEAR 0	2011	(1) RURAL AND RESIDENTIAL	(2) COMMERCIAL	(3) INDUSTRIAL	(4) STREET-HWY LIGHTING	(5) SALES FOR RESALE b	(6) OTHER
January		158,216	123,731	66,523	1,261	0	24,758
February		140,236	113,132	62,493	1,261	0	23,104
March		122,779	111,577	64,523	1,275	0	23,457
April		100,290	109,587	62,915	1,260	0	22,711
May		88,124	111,016	64,687	1,253	0	23,357
June		112,761	127,591	67,677	1,271	0	25,882
July		142,049	135,751	69,456	1,257	0	26,354
August		148,441	136,288	71,263	1,263	0	26,538
September		132,477	131,526	69,447	1,259	0	26,884
October		97,181	114,683	65,890	1,255	0	23,901
November		93,502	108,064	63,222	1,251	0	22,005
December		132,710	120,747	64,762	1,261	0	23,593
YEAR 1	2012						
January		160,092	126,645	68,451	1,278	0	24,462
February		141,655	115,777	64,266	1,278	0	22,814
March		123,908	114,179	66,307	1,293	0	23,140
April		101,073	112,141	64,617	1,277	0	22,320
May		88,790	113,571	66,365	1,270	0	22,937
June		113,457	130,548	69,450	1,288	0	25,330
July		142,578	138,881	71,271	1,274	0	25,816
August		148,757	139,415	73,118	1,280	0	26,001
September		132,441	134,509	71,229	1,276	0	26,274
October		96,913	117,312	67,596	1,272	0	23,353
November		93,159	110,537	64,855	1,268	0	21,436
December		131,999	123,511	66,435	1,278	0	23,017

(a) Includes EE Impacts.

(b) Sales for resale to municipals.

FIGURE B-12 PART 2

DUKE ENERGY KENTUCKY SYSTEM

SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR) c

AFTER EE

YEAR 0	2011	(7) (1+2+3 +4+5+6) **TOTAL** **CONSUMPTION**	(8) **LOSSES AND** **UNACCOUNTED** **FOR d**	(9) (7+8) **NET ENERGY** **FOR LOAD**
--------		-----------	-----------	----------
January		374,490	15,166	389,656
February		340,227	2,359	342,587
March		323,612	11,331	334,943
April		296,763	5,669	302,432
May		288,437	29,343	317,779
June		335,182	34,161	369,342
July		374,868	31,743	406,611
August		383,792	30,122	413,914
September		361,592	(13,200)	348,392
October		302,910	14,777	317,687
November		288,044	21,965	310,008
December		343,074	22,875	365,950
YEAR 1	2012			

January		380,928	16,505	397,433
February		345,790	531	346,321
March		328,827	11,966	340,793
April		301,428	6,079	307,506
May		292,931	28,615	321,546
June		340,073	34,876	374,948
July		379,821	32,456	412,277
August		388,572	31,533	420,104
September		365,729	(14,456)	351,272
October		306,446	15,283	321,729
November		291,256	22,377	313,633
December		346,240	23,342	369,582

(c) Includes EE Impacts

(d) Transmission, transformer and other losses and energy unaccounted for.

Section 7. (2) (a)

DUKE ENERGY KENTUCKY SYSTEM
ELECTRIC CUSTOMERS BY MAJOR CLASSIFICATIONS
ANNUAL AVERAGES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	OTHER PUBLIC AUTHORITY
2006	117,722	13,139	389	326	966
2007	118,843	13,302	392	355	976
2008	119,534	13,423	390	378	978
2009	119,743	13,318	383	392	979
2010	120,099	13,355	382	400	977
2011	120,327	13,366	378	402	965
2012	121,224	13,443	379	406	973
2013	122,119	13,519	380	421	986
2014	123,114	13,608	382	440	999
2015	124,113	13,705	383	463	1,008
2016	125,031	13,792	384	487	1,013
2017	125,919	13,868	386	512	1,018
2018	126,788	13,942	387	538	1,023
2019	127,651	14,012	388	565	1,027
2020	128,525	14,081	389	595	1,031
2021	129,415	14,151	390	627	1,035
2022	130,312	14,221	391	662	1,039
2023	131,218	14,291	392	699	1,043
2024	132,139	14,361	393	739	1,047
2025	133,087	14,431	394	783	1,050
2026	134,054	14,504	395	831	1,054
2027	135,029	14,575	395	881	1,057
2028	136,026	14,645	396	936	1,061
2029	137,031	14,716	397	995	1,065
2030	138,034	14,784	398	1,058	1,069
2031	139,070	14,852	398	1,125	1,073

NOTE: 2011 FIGURES REPRESENT TWELVE MONTHS FORECAST

Section 7. (2) (b) and (c)

DUKE ENERGY KENTUCKY SYSTEM
WEATHER NORMALIZED
ANNUAL ENERGY (MWh)

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	OTHER PUBLIC AUTHORITY
2006	1,452,189	1,382,948	782,957	17,338	305,586
2007	1,457,294	1,436,807	798,497	15,988	312,422
2008	1,466,723	1,444,196	801,117	16,001	313,886
2009	1,464,647	1,413,850	735,194	15,348	304,648
2010	1,467,402	1,429,053	776,804	15,167	306,566

	INTER DEPARTMENT	COMPANY USE	TOTAL CONSUMPTION	LOSSES AND UNACCOUNTED FOR	NET ENERGY FOR LOAD
2006	2,237	2,566	3,945,823	134,551	4,080,374
2007	703	662	4,022,373	179,450	4,201,823
2008	833	860	4,043,617	170,467	4,214,084
2009	751	887	3,935,325	150,730	4,086,055
2010	885	818	3,996,695	110,867	4,107,562

DUKE ENERGY KENTUCKY SYSTEM
WEATHER NORMALIZED
AND PEAKS (MW)

	SUMMER PEAK (MW)	WINTER PEAK (MW)
2006	897	756
2007	862	749
2008	871	749
2009	875	725
2010	879	719

Section 7.(7).a

VARIABLE	DESCRIPTION
@ISPERIOD("6/11/1976")	QUALITATIVE VARIABLE - JUNE 11, 1976
@ISPERIOD("6/18/1976")	QUALITATIVE VARIABLE - JUNE 18, 1976
@ISPERIOD("1/27/1977")	QUALITATIVE VARIABLE - JANUARY 27, 1977
@ISPERIOD("1/28/1977")	QUALITATIVE VARIABLE - JANUARY 28, 1977
@ISPERIOD("7/5/1993")	QUALITATIVE VARIABLE - JULY 5, 1993
@ISPERIOD("7/5/1999")	QUALITATIVE VARIABLE - JULY 5, 1999
@ISPERIOD("8/13/1999")	QUALITATIVE VARIABLE - AUGUST 13, 1999
@ISPERIOD("8/17/1999")	QUALITATIVE VARIABLE - AUGUST 17, 1999
@ISPERIOD("1/23/2003")	QUALITATIVE VARIABLE - JANUARY 23, 2003
@ISPERIOD("7/7/2010")	QUALITATIVE VARIABLE - JULY 7, 2010
@ISPERIOD("1980M02")	QUALITATIVE VARIABLE - FEBRUARY, 1980
@ISPERIOD("1982M06")	QUALITATIVE VARIABLE - JUNE, 1982
@ISPERIOD("1986Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 1986
@ISPERIOD("1986Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 1986
@ISPERIOD("1988Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 1988
@ISPERIOD("1988Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 1988
@ISPERIOD("1990Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 1990
@ISPERIOD("1991M03")	QUALITATIVE VARIABLE - MARCH, 1991
@ISPERIOD("1991M04")	QUALITATIVE VARIABLE - APRIL, 1991
@ISPERIOD("1991M06")	QUALITATIVE VARIABLE - JUNE, 1991
@ISPERIOD("1991M11")	QUALITATIVE VARIABLE - NOVEMBER, 1991
@ISPERIOD("1991Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 1991
@ISPERIOD("1991Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 1991
@ISPERIOD("1991Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 1991
@ISPERIOD("1992Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 1992
@ISPERIOD("1992Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 1992
@ISPERIOD("1993M09")	QUALITATIVE VARIABLE - SEPTEMBER, 1993
@ISPERIOD("1993M10")	QUALITATIVE VARIABLE - OCTOBER, 1993
@ISPERIOD("1993M11")	QUALITATIVE VARIABLE - NOVEMBER, 1993
@ISPERIOD("1993Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 1993
@ISPERIOD("1993Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 1993
@ISPERIOD("1994M02")	QUALITATIVE VARIABLE - FEBRUARY, 1994
@ISPERIOD("1994M05")	QUALITATIVE VARIABLE - MAY, 1994
@ISPERIOD("1994Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 1994
@ISPERIOD("1995M04")	QUALITATIVE VARIABLE - APRIL, 1995
@ISPERIOD("1995M05")	QUALITATIVE VARIABLE - MAY, 1995
@ISPERIOD("1995M08")	QUALITATIVE VARIABLE - AUGUST, 1995
@ISPERIOD("1996Q2")	QUALITATIVE VARIABLE – SECOND QUARTER, 1996
@ISPERIOD("1996Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 1996
@ISPERIOD("1997Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 1997
@ISPERIOD("1998M05")	QUALITATIVE VARIABLE - MAY, 1998
@ISPERIOD("1998M07")	QUALITATIVE VARIABLE - JULY, 1998
@ISPERIOD("1998M10")	QUALITATIVE VARIABLE - OCTOBER, 1998
@ISPERIOD("1998Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 1998
@ISPERIOD("1998Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 1998
@ISPERIOD("1999M02")	QUALITATIVE VARIABLE - FEBRUARY, 1999
@ISPERIOD("1999M06")	QUALITATIVE VARIABLE - JUNE, 1999
@ISPERIOD("1999M10")	QUALITATIVE VARIABLE - OCTOBER, 1999
@ISPERIOD("1999M11")	QUALITATIVE VARIABLE - NOVEMBER, 1999
@ISPERIOD("1999M12")	QUALITATIVE VARIABLE - DECEMBER, 1999
@ISPERIOD("1999Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 1999
@ISPERIOD("1999Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 1999

@ISPERIOD("2000M01")	QUALITATIVE VARIABLE - JANUARY, 2000
@ISPERIOD("2000M04")	QUALITATIVE VARIABLE - APRIL, 2000
@ISPERIOD("2000M05")	QUALITATIVE VARIABLE - MAY, 2000
@ISPERIOD("2000M06")	QUALITATIVE VARIABLE - JUNE, 2000
@ISPERIOD("2000M07")	QUALITATIVE VARIABLE - JULY, 2000
@ISPERIOD("2000M08")	QUALITATIVE VARIABLE - AUGUST, 2000
@ISPERIOD("2000M10")	QUALITATIVE VARIABLE - OCTOBER, 2000
@ISPERIOD("2000M12")	QUALITATIVE VARIABLE - DECEMBER, 2000
@ISPERIOD("2000Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 2000
@ISPERIOD("2000Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 2000
@ISPERIOD("2000Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 2000
@ISPERIOD("2000Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2000
@ISPERIOD("2001M01")	QUALITATIVE VARIABLE - JANUARY, 2001
@ISPERIOD("2001M02")	QUALITATIVE VARIABLE - FEBRUARY, 2001
@ISPERIOD("2001M03")	QUALITATIVE VARIABLE - MARCH, 2001
@ISPERIOD("2001M04")	QUALITATIVE VARIABLE - APRIL, 2001
@ISPERIOD("2001M05")	QUALITATIVE VARIABLE - MAY, 2001
@ISPERIOD("2001M06")	QUALITATIVE VARIABLE - JUNE, 2001
@ISPERIOD("2001M07")	QUALITATIVE VARIABLE - JULY, 2001
@ISPERIOD("2001Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 2001
@ISPERIOD("2001Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 2001
@ISPERIOD("2001Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2001
@ISPERIOD("2002M02")	QUALITATIVE VARIABLE - FEBRUARY, 2002
@ISPERIOD("2002M04")	QUALITATIVE VARIABLE - APRIL, 2002
@ISPERIOD("2002M05")	QUALITATIVE VARIABLE - MAY, 2002
@ISPERIOD("2002M06")	QUALITATIVE VARIABLE - JUNE, 2002
@ISPERIOD("2002M07")	QUALITATIVE VARIABLE - JULY, 2002
@ISPERIOD("2002M08")	QUALITATIVE VARIABLE - AUGUST, 2002
@ISPERIOD("2002M10")	QUALITATIVE VARIABLE - OCTOBER, 2002
@ISPERIOD("2002M12")	QUALITATIVE VARIABLE - DECEMBER, 2002
@ISPERIOD("2002Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 2002
@ISPERIOD("2002Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 2002
@ISPERIOD("2002Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 2002
@ISPERIOD("2003M01")	QUALITATIVE VARIABLE - JANUARY, 2003
@ISPERIOD("2003M12")	QUALITATIVE VARIABLE - DECEMBER, 2003
@ISPERIOD("2003Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 2003
@ISPERIOD("2003Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 2003
@ISPERIOD("2003Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2003
@ISPERIOD("2004M01")	QUALITATIVE VARIABLE - JANUARY, 2004
@ISPERIOD("2004M03")	QUALITATIVE VARIABLE - MARCH, 2004
@ISPERIOD("2004M05")	QUALITATIVE VARIABLE - MAY, 2004
@ISPERIOD("2004M06")	QUALITATIVE VARIABLE - JUNE, 2004
@ISPERIOD("2004M11")	QUALITATIVE VARIABLE - NOVEMBER, 2004
@ISPERIOD("2004M12")	QUALITATIVE VARIABLE - DECEMBER, 2004
@ISPERIOD("2004Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 2004
@ISPERIOD("2004Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2004
@ISPERIOD("2005M01")	QUALITATIVE VARIABLE - JANUARY, 2005
@ISPERIOD("2005M02")	QUALITATIVE VARIABLE - FEBRUARY, 2005
@ISPERIOD("2005M03")	QUALITATIVE VARIABLE - MARCH, 2005
@ISPERIOD("2005M08")	QUALITATIVE VARIABLE - AUGUST, 2005
@ISPERIOD("2005Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 2005
@ISPERIOD("2005Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2005
@ISPERIOD("2006M02")	QUALITATIVE VARIABLE - FEBRUARY, 2006
@ISPERIOD("2006M09")	QUALITATIVE VARIABLE - SEPTEMBER, 2006

@ISPERIOD("2006M10")	QUALITATIVE VARIABLE - OCTOBER, 2006
@ISPERIOD("2007M02")	QUALITATIVE VARIABLE - FEBRUARY, 2007
@ISPERIOD("2007M04")	QUALITATIVE VARIABLE - APRIL, 2007
@ISPERIOD("2007M05")	QUALITATIVE VARIABLE - MAY, 2007
@ISPERIOD("2007M06")	QUALITATIVE VARIABLE - JUNE, 2007
@ISPERIOD("2007M10")	QUALITATIVE VARIABLE - OCTOBER, 2007
@ISPERIOD("2007Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2007
@ISPERIOD("2008M10")	QUALITATIVE VARIABLE - OCTOBER, 2008
@ISPERIOD("2008Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 2008
@ISPERIOD("2008Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 2008
@ISPERIOD("2008Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2008
@ISPERIOD("2009M05")	QUALITATIVE VARIABLE - MAY, 2009
@ISPERIOD("2009Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 2009
@ISPERIOD("2009Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 2009
@ISPERIOD("2010M02")	QUALITATIVE VARIABLE - FEBRUARY, 2010
@ISPERIOD("2010M03")	QUALITATIVE VARIABLE - MARCH, 2010
@ISPERIOD("2010M05")	QUALITATIVE VARIABLE - MAY, 2010
@ISPERIOD("2010M10")	QUALITATIVE VARIABLE - OCTOBER, 2010
@ISPERIOD("2010Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 2010
@ISPERIOD("2010Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 2010
@ISPERIOD("2010Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2010
@MONTH=1	QUALITATIVE VARIABLE - JANUARY
@MONTH=10	QUALITATIVE VARIABLE - OCTOBER
@MONTH=11	QUALITATIVE VARIABLE - NOVEMBER
@MONTH=12	QUALITATIVE VARIABLE - DECEMBER
@MONTH=2	QUALITATIVE VARIABLE - FEBRUARY
@MONTH=3	QUALITATIVE VARIABLE - MARCH
@MONTH=4	QUALITATIVE VARIABLE - APRIL
@MONTH=5	QUALITATIVE VARIABLE - MAY
@MONTH=6	QUALITATIVE VARIABLE - JUNE
@MONTH=7	QUALITATIVE VARIABLE - JULY
@MONTH=8	QUALITATIVE VARIABLE - AUGUST
@MONTH=9	QUALITATIVE VARIABLE – SEPTEMBER
@QUARTER=1	QUALITATIVE VARIABLE - FIRST QUARTER
@QUARTER=2	QUALITATIVE VARIABLE - SECOND QUARTER
@QUARTER=3	QUALITATIVE VARIABLE - THIRD QUARTER
@QUARTER=4	QUALITATIVE VARIABLE - FOURTH QUARTER
AMLOW	MINIMUM HOURLY TEMPERATURE - MORNING
AMPEAK	QUALITATIVE VARIABLE - MORNING PEAK
APGIND_OH_KY	SERVICE AREA AVERAGE PRICE OF GAS FOR INDUSTRIAL CUSTOMERS
APGOPA_OH_KY	SERVICE AREA AVERAGE PRICE OF GAS FOR OPA CUSTOMERS
APPLSTK_EFF_OH_KY	EFFICIENT APPLIANCE STOCK
BASE	BUTLER COUNTY BASE AMOUNT OF MWH SALES - INDUSTRIAL - PRIMARY METAL INDUSTRIES
CDD_OH_KY_65	COOLING DEGREE DAYS
CDDB_OH_KY_65	BILLING COOLING DEGREE DAYS
CDDB_OH_KY_65_0_100	=MINIMUM(CDDB_OH_KY,100)
CDDB_OH_KY_65_100	=MAXIMUM(CDDB_OH_KY-100,0)
CPI	CONSUMER PRICE INDEX (ALL URBAN) - ALL ITEMS
CUSRES_OH_KY	SERVICE AREA ELECTRIC CUSTOMERS - RESIDENTIAL
D_072180_091498	QUALITATIVE VARIABLE - JULY 21, 1980 TO SEPTEMBER 14, 1998
D_080107_082907	QUALITATIVE VARIABLE - AUGUST 1, 2007 TO AUGUST 29, 2007
D_1965M01_2001M12	QUALITATIVE VARIABLE - JANUARY, 1965 THRU DECEMBER, 2001
D_1965M01_2002M12	QUALITATIVE VARIABLE - JANUARY, 1965 THRU DECEMBER, 2002

D_1965M01_2007M09	QUALITATIVE VARIABLE - JANUARY, 1965 THRU SEPTEMBER, 2007
D_1965Q1_1985Q4	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO FOURTH QUARTER, 1985
D_1965Q1_1986Q4	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU FOURTH QUARTER, 1986
D_1965Q1_1990Q4	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU FOURTH QUARTER, 1990
D_1965Q1_1995Q4	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO FOURTH QUARTER, 1995
D_1965Q1_1998Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO SECOND QUARTER, 1998
D_1965Q1_2001Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO SECOND QUARTER, 2001
D_1965Q1_2001Q3	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU THIRD QUARTER, 2001
D_1965Q1_2005Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU FIRST QUARTER, 2005
D_1976M01_1984M12	QUALITATIVE VARIABLE - JANUARY, 1976 THRU DECEMBER, 1984
D_1976Q1_1989Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1976 TO SECOND QUARTER, 1989
D_1980Q1_2005Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1980 TO SECOND QUARTER, 2005
D_1987Q1_1991Q3	QUALITATIVE VARIABLE - FIRST QUARTER, 1987 THRU THIRD QUARTER, 1991
D_1998Q3_2001Q2	QUALITATIVE VARIABLE - THIRD QUARTER, 1998 THRU SECOND QUARTER, 2001
D_1999Q1_2001Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1999 THRU SECOND QUARTER, 2001
D_2000M08_2001M12	QUALITATIVE VARIABLE - AUGUST, 2000 THRU DECEMBER, 2001
D_2000Q3_2001Q2	QUALITATIVE VARIABLE - THIRD QUARTER, 2000 THRU SECOND QUARTER, 2001
D_2001M09_2002M06	QUALITATIVE VARIABLE - SEPTEMBER, 2001 THRU JUNE, 2002
D_2002M07_2003M01	QUALITATIVE VARIABLE - JULY, 2002 THRU JANUARY, 2003
D_DJF	=(@MONTH=12+@MONTH=1+@MONTH=2)
D_JJA	=(@MONTH=6+@MONTH=7+@MONTH=8)
DAYS	NUMBER OF DAYS IN THE MONTH
DS_KW_IND_OH_KY	SERVICE AREA DS RATE FOR DEMAND FOR INDUSTRIAL CUSTOMERS
DS_KW_OPA_OH_KY	SERVICE AREA DS RATE FOR DEMAND FOR OTHER PUBLIC AUTHORITIES CUSTOMERS
DS_KWH_COM_OH_KY	SERVICE AREA DS RATE FOR USAGE FOR COMMERCIAL CUSTOMERS
DS_KWH_IND_OH_KY	SERVICE AREA DS RATE FOR USAGE FOR INDUSTRIAL CUSTOMERS
DS_KWH_OPA_OH_KY	SERVICE AREA DS RATE FOR USAGE FOR OTHER PUBLIC AUTHORITIES CUSTOMERS
E90X_OH_KY	SERVICE AREA EMPLOYMENT - STATE AND LOCAL GOVERNMENT
ECOM_OH_KY	SERVICE AREA EMPLOYMENT - COMMERCIAL
EFF_CAC_OH_KY	EFFICIENCY OF CENTRAL AIR CONDITIONING UNITS IN SERVICE AREA
EFF_EHP_OH_KY	EFFICIENCY OF ELECTRIC HEAT PUMP UNITS IN SERVICE AREA
EFF_RAC_OH_KY	EFFICIENCY OF WINDOW AIR CONDITIONING UNITS IN SERVICE AREA
HDDB_OH_KY_59	BILLING HEATING DEGREE DAYS
HDDB_OH_KY_59_0_500	=MINIMUM(HDDB_OH_KY,500)
HDDB_OH_KY_59_500	=MAXIMUM(HDDB_OH_KY-500,0)
JQINDN311_312_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - FOOD AND PRODUCTS
JQINDN322_326_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - PAPER AND PRODUCTS
JQINDN325_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - CHEMICALS AND PRODUCTS
JQINDN331_BUTLER	BUTLER COUNTY INDUSTRIAL PRODUCTION INDEX - PRIMARY METAL INDUSTRIES
JQINDN331_CMSA	CINCINNATI CMSA INDUSTRIAL PRODUCTION INDEX - PRIMARY METAL INDUSTRIES
JQINDN332_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - FABRICATED METALS
JQINDN333_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - INDUSTRIAL MACHINERY & EQUIPMENT
JQINDN334_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - COMPUTER AND ELECTRONICS
JQINDN335_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - ELECTRICAL EQUIPMENT
JQINDN3364_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - AIRCRAFT AND PARTS
JQINDN361_62_63_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - MOTOR VEHICLES AND PARTS
JQINDNAOI_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION - ALL OTHER INDUSTRIES
JULY4WEEK	QUALITATIVE VARIABLE FOR THE WEEK OF JULY 4TH
KWHCOM_OH_KY	SERVICEA KWH SALES - COMMERCIAL
KWHOPALWP_OH_KY	SERVICE AREA KWH SALES - OPA LESS WATER PUMPING
KWHOPAWP_OH_KY	SERVICE AREA KWH SALES - OPA WATER PUMPING
KWHRES_OH_KY	SERVICE AREA KWH SALES - RESIDENTIAL
KWHSEND_OH_KY_WN	SERVICE AREA KWH SENDOUT – WEATHER NORMALIZED
KWHSL_OH_KY	SERVICE AREA KWH SALES – STREET LIGHTING
MAUG	QUALITATIVE VARIABLE - AUGUST
MDEC	QUALITATIVE VARIABLE - DECEMBER
MFEB	QUALITATIVE VARIABLE - FEBRUARY
MJAN	QUALITATIVE VARIABLE - JANUARY
MJUL	QUALITATIVE VARIABLE - JULY
MJUN	QUALITATIVE VARIABLE - JUNE

MMAR	QUALITATIVE VARIABLE - MARCH
MP_RES_OH_KY	MARGINAL PRICE OF ELECTRICITY - RESIDENTIAL
MSEP	QUALITATIVE VARIABLE - SEPTEMBER
MWHN311_312_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - FOOD AND PRODUCTS
MWHN322_326_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - PAPER AND PRODUCTS
MWHN325_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - CHEMICALS AND PRODUCTS
MWHN331_BUTLER	BUTLER COUNTY MWH SALES - INDUSTRIAL - PRIMARY METAL INDUSTRIES
MWHN331LBUTLER_OH_KY	SERVICE AREA MWH SALES LESS BUTLER COUNTY - INDUSTRIAL - PRIMARY METAL INDUSTRIES
MWHN332_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - FABRICATED METALS
MWHN333_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - INDUSTRIAL MACHINERY AND EQUIPMENT
MWHN334_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - COMPUTER AND ELECTRONICS
MWHN335_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - ELECTRICAL EQUIPMENT
MWHN3361_62_63_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - MOTOR VEHICLES AND PARTS
MWHN3364_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - TRANSPORTATION EQUIPMENT OTHER THAN MOTOR VEHICLES AND PARTS
MWHNAOI_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - ALL OTHER INDUSTRIES
MWSPEAK_OH_KY	SERVICE AREA MW PEAK - SUMMER
MWWPEAK_OH_KY	SERVICE AREA MW PEAK - WINTER
N_OH_KY	SERVICE AREA TOTAL POPULATION
PMHIGH	MAXIMUM HOURLY TEMPERATURE - AFTERNOON
PMHUMIDATHIGH	HUMIDITY - AFTERNOON
PMLOW	MINIMUM HOURLY TEMPERATURE - EVENING
PMPEAK	QUALITATIVE VARIABLE - EVENING PEAK
PRECIP_OH_KY	SERVICE AREA PRECIPITATION
PREVPMHIGH	MAXIMUM HOURLY TEMPERATURE - PREVIOUS AFTERNOON
PREVPMLOW	MINIMUM HOURLY TEMPERATURE - PREVIOUS AFTERNOON
SAT_CAC_EFF	=EFF_CAC_OH_KY*(SAT_EHP_OH_KY+SAT_CACNHP_OH_KY)
SAT_CACNHP_OH_KY	SERVICE AREA SATURATION OF CENTRAL AIR CONDITIONING WITHOUT HEAT PUMP
SAT_EH_EFF	=(SAT_ER_OH_KY+(SAT_EHP_OH_KY*EFF_EHP_OH_KY))
SAT_EHP_OH_KY	SERVICE AREA SATURATION OF ELECTRIC HEAT PUMPS - RESIDENTIAL
SAT_ER_OH_KY	SATURATION RATE OF ELECTRIC RESISTANCE HEATERS IN SERVICE AREA
SAT_RAC_EFF	=EFF_RAC_OH_KY*SAT_RAC_OH_KY
SAT_RAC_OH_KY	SERVICE AREA SATURATION OF WINDOW AIR CONDITIONING SERVICE AREA
SAT_SL_OH_KY	=(0.5*SATMERC_OH_KY)+(0.5*SATSODVAP_OH_KY)
SATMERC_OH_KY	SERVICE AREA SATURATION OF MERCURY VAPOR STREET LIGHTING
SATSODVAP_OH_KY	SERVICE AREA SATURATION OF SODIUM VAPOR STREET LIGHTING
TS_KW_IND_OH_KY	SERVICE AREA TS RATE FOR DEMAND FOR INDUSTRIAL CUSTOMERS
TS_KWH_IND_OH_KY	SERVICE AREA TS RATE FOR USAGE FOR INDUSTRIAL CUSTOMERS
WINDAM	WIND SPEED - MORNING
WPI0561	WHOLESALE PRICE INDEX FOR CRUDE PETROLEUM
XMAS	QUALITATIVE VARIABLE - CHRISTMAS WEEK
YP_OH_KY	SERVICE AREA PERSONAL INCOME

Duke Energy®

Kentucky

The Duke Energy Kentucky 2011 Integrated Resource Plan

July 1, 2011

Appendix C – Energy Efficiency & Demand Side Management

APPENDIX C – ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT

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C. DEMAND-SIDE MANAGEMENT RESOURCES

1. INTRODUCTION

Since the previous IRP filed in 2007, Duke Energy Kentucky has devoted its DSM[3] efforts to the implementation of the following eleven programs that have been developed in conjunction with the DSM Collaborative:

Program 1: Residential Conservation and Energy Education
Program 2: Residential Home Energy House Call
Program 3: Residential Comprehensive Energy Education Program (NEED)
Program 4: Program Administration, Development & Evaluation Funds
Program 5: Payment Plus
Program 6: Power Manager
Program 7: Energy Star® Products
Program 8: Energy Efficiency Website
Program 9: Personal Energy Report (PER)
Program 10: C&I High Efficiency Incentive (for Businesses and Schools)
Program 11: PowerShare®

There are two collaborative groups: a Residential DSM Collaborative and a Commercial and Industrial DSM Collaborative. Both contain local stakeholders as well as other parties interested in the development and implementation of DSM or conservation EE and DR programs.

The Commission has been kept appraised of the activities and progress made on these programs with the DSM collaborative process through annual status reports filed with the Commission in the Fall of each year.

[3] Kentucky Revised Statutes (KRS) § 278.010 define Demand Side Management as "any conservation, load management, or other utility activity intended to influence the level or pattern of customer usage or demand including home energy assistance programs." KY. REV. STAT. ANN. § 278.010 (Michie 2007).

Under the current DSM Agreement and prior Commission Orders, all of these programs will remain in effect through December 31, 2012, as Ordered in Case No. 2009-00444.

Duke Energy Kentucky is also seeking approval to implement a new energy efficiency program called Residential Smart Saver as further described below.

2. COST-EFFECTIVENESS OF PROGRAMS

All energy efficiency programs are screened for cost-effectiveness. The Company's measures and programs are analyzed using DSMore, a financial analysis tool designed to evaluate the costs, benefits and risk of energy efficiency programs and measures. DSMore estimates the value of an energy efficiency measure at an hourly level across distributions of weather and/or energy costs or prices. By examining energy efficiency performance and cost effectiveness over a wide variety of weather and cost conditions, the Company is better positioned to measure the risks and benefits of employing energy efficiency measures in the same way traditional generation capacity additions are vetted, and further, to ensure that demand-side resources are compared to supply-side resources on a comparable basis.

The analysis of energy efficiency cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test (UCT), Rate Impact Measure (RIM) Test, Total Resource Cost (TRC) Test, and Participant Test. DSMore provides the results of these tests for any type of energy efficiency program (demand response and/or energy conservation).

- The UCT compares utility benefits (avoided energy and capacity related costs) to utility costs incurred to implement the program such as marketing, customer incentives, and measure offset costs, but does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, and the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs and load (line) losses.

- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.
- The TRC test compares the total benefits to the utility and participants relative to the costs of utility program implementation and costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test (below), however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC though some precedent exists in other jurisdictions to consider non-energy benefits in this test.
- The Participant Test compares the benefits to the participant through bill savings and incentives from the utility, relative to the costs to the participant for implementing the energy efficiency measure. The costs can include capital cost, as well as increased annual operating costs, if applicable.

The use of multiple tests can ensure the development of a reasonable set of DSM/EE programs and indicate the likelihood that customers will participate. It should also be noted that none of the tests described above include external benefits to participants and non-participants that can also offset the costs of the programs.

Table C-1 summarizes the cost effectiveness results for current programs as of the most recent Annual Update filing.

Table C-1
Cost Effectiveness Test Results

Program	UCT	TRC	RIM	Participant
Residential Conservation and Energy Education	1.40	1.40	0.92	NA
Refrigerator Replacement	0.95	0.95	0.53	NA
Residential Home Energy House Call	0.98	1.19	0.58	NA
Residential Comprehensive Energy Education Program (NEED)	0.37	0.37	0.30	NA
Power Manager	1.95	2.20	1.95	NA
Energy Star Products	6.25	3.56	0.89	NA
Energy Efficiency Website	2.51	3.32	0.73	NA
Personal Energy Report (PER)	4.19	8.87	0.83	NA
C&I High Efficiency Incentive (for Businesses and Schools)				
Lighting	4.72	2.00	1.30	2.41
HVAC	1.08	1.57	0.72	3.54
Motors	19.57	10.91	1.63	12.35
Other	1.67	0.90	0.86	1.44
Custom Incentives for Schools	4.20	0.41	1.41	0.43
PowerShare	2.92	2.92	1.15	NA

3. CURRENT DSM PROGRAMS

This section provides a description of each current program DSM program offered by Duke Energy Kentucky:

Program 1: Residential Conservation and Energy Education

The Residential Conservation and Energy Education program is designed to help the Company's income-qualified customers reduce their energy consumption and lower their energy cost. This program specifically focuses on LIHEAP (Low Income Home Energy Assistance Program) customers that meet the income qualification level (*i.e.*, income below 130% of the federal poverty level). This program uses the LIHEAP intake process as well as other community outreach to improve participation. The program provides direct installation of weatherization and energy-efficiency measures and educates Duke Energy Kentucky's income-qualified customers about their energy usage and other opportunities to reduce energy consumption and lower their costs. The program has provided weatherization services to 251 homes in 2000; 283 in 2001; 203 in

2002; 252 in 2003; 252 in 2004; 130 in 2005; 232 in 2006; 252 in 2007; 265 in 2008 and 222 in 2009. For the fiscal year 2010[4], 199 homes were weatherized.

The program is structured so that the homes needing the most work, and having the highest energy use per square foot, receive the most funding. The program does this by placing each home into one of two "Tiers." This allows the implementing agencies to spend the limited budgets where there is the most significant potential for savings that is also cost effective. For each home in Tier 2, the field auditor uses the National Energy Audit Tool (NEAT) to determine which specific measures are cost effective for that home. The specific services provided within each Tier are described below.

The tier structure is defined as follows:

	Therm / square foot	kWh use/ square foot	Investment Allowed
Tier 1	0 < 1 therm / ft2	0 < 7 kWh / ft2	Up to $600
Tier 2	1 + therms / ft2	7 + kWh / ft2	All SIR* ≥ 1.5 up to $4K

*SIR = Savings - Investment Ratio

Tier One Services

Tier 1 services are provided to customers by Duke Energy Kentucky, through its subcontractors. Customers are considered Tier 1, if they use less than 1 therm per square foot per year or less than 7 kWh per square foot per year based on the last year of usage (weather adjusted) of Company supplied fuels. Square footage of the dwelling is based on conditioned space only, whether occupied or unoccupied. It does not include unconditioned or semi-conditioned space (non-heated basements). The total program dollars allowed per home for Tier One services is $600.00 per home.

Tier One services are as follows:

- Furnace Tune-up & Cleaning
- Furnace replacement if investment in repair over $500

[4] July 1, 2009 to June 30, 2010.

- Venting check & repair
- Water Heater Wrap
- Pipe Wrap
- Waterbed mattress covers
- Cleaning of refrigerator coils
- Cleaning of dryer vents
- Compact Fluorescent Light (CFL) Bulbs
- Low-flow shower heads and aerators
- Weather-stripping doors & windows
- Limited structural corrections that affect health, safety, and energy up to $100
- Energy Education

Tier Two Services

Duke Energy Kentucky will provide Tier Two services to a customer, if they use at least 1 therm or at least 7 kWh per square foot per year based on the last year of usage of Duke Energy Kentucky supplied fuels.

Tier Two services are as follows:

- Tier One services plus:
- Additional cost-effective measures (with SIR $\geq$ 1.5) based upon the results of the NEAT audit. Through the NEAT audit, the utility can determine if the cost of energy saving measures pay for themselves over the life of the measure as determined by a standard heat loss/economic calculation (NEAT audit) utilizing the cost of gas and electric as provided by Duke Energy Kentucky. Such items can include but are not limited to attic insulation, wall insulation, crawl space insulation, floor insulation and sill box insulation. Safety measures applying to the installed technologies can be included within the scope of work considered in the NEAT audit as long as the SIR is greater than 1.5 including the safety changes.

Regardless of placement in a specific tier, Duke Energy Kentucky provides energy education to all customers in the program.

To increase the cost-effectiveness of this program and to provide more savings and bill control for the customer, the Collaborative and Duke Energy Kentucky proposed in the September 27, 2002, filing in Case No. 2002-00358, and subsequently received approval to expand this program, to include refrigerators as a qualified measure in owner-occupied homes. To determine replacement, the program weatherization provider performs a two-hour meter test of the existing refrigerator unit. If it is a high-energy consuming refrigerator, as determined by this test, the unit is replaced. The program replaces about half of the units tested. Replacing with a new Energy Star qualified refrigerator, which uses approximately 400 kWh, results in an overall savings to the average customer typically in excess of 1,000 kWh per year.

Refrigerators tested and replaced:

- 2003 = 116 tested and 47 replaced
- 2004 = 163 tested and 73 replaced
- 2005 = 115 tested and 39 replaced
- 2006 = 116 tested and 52 replaced
- 2007 = 136 tested and 72 replaced
- 2008 = 173 tested and 85 replaced
- 2009 = 153 tested and 66 replaced
- 2010 = 167 tested and 92 replaced

The existing refrigerator being replaced is removed from the home and destroyed in an environmentally appropriate manner to assure that the units are not used as a second refrigerator in the home or do not end up in the secondary appliance market.

Program 2: Residential Home Energy House Call

The Home Energy House Call (HEHC) program is administered by Duke Energy Kentucky contractor Wisconsin Energy Conservation Corporation, Inc. (WECC). WECC has been administering and implementing programs for 25 years. It is one of the largest program operators in the region. WECC's knowledge of home energy audits comes from years of experience administering weatherization programs for income eligible customers and implemented through subcontractor Thermal Scan Inspections, Inc. (TSI). TSI is located in Carmel, Indiana. TSI has been in the business of providing a wide array of inspection services to commercial and industrial businesses, municipalities, contractors and homeowners to identify, repair and protect homes, buildings, equipment and structures from moisture, leaks, corrosion and inefficient energy usage since 1979. They received the **Energy Star** for Homes **Outstanding Achievement Award** two years in a row recognizing the important contribution they make to energy efficient construction and environmental protection. Together, WECC and TSI provide the administration, marketing, staff, tracking, systems, logistics, training, customer service, scheduling and technical support required to support Duke Energy Kentucky's HEHC program. The HEHC program provides a comprehensive walk through in-home analysis by a qualified home energy specialist to identify energy savings opportunities in homes. The energy specialist analyzes the total home energy usage, checks the home for air infiltration, examines insulation levels in different areas of the home, and checks appliances and heating/cooling systems. A comprehensive report specific to the customer's home and energy usage is then provided to the customer at the time of the audit. The report focuses on the building envelope improvements as well as low-cost and no-cost improvements to save energy. At the time of the home audit, the customer receives a kit containing several energy saving measures at no cost. The measures include a low-flow showerhead, two aerators, outlet gaskets, and three compact fluorescent bulbs. The auditors will offer to install these measures, if approved by the customer, so that the customer can begin realizing an immediate savings on their electric bill, and to help insure proper installation and use.

For the period of July 1, 2009 through June 30, 2010, a total of 482 audits were completed in Kentucky. During this filing period, direct mail brochures were mailed to customers in an effort to acquire the proposed participation for this program process. To date, customer satisfaction ratings for the program continue to remain high.

The auditors carry laptop computers on-site and can enter the data collected into the software directly, eliminating error from third party interpretation, and also allowing a customer to receive their energy audit information immediately on site.

Program 3: Residential Comprehensive Energy Education

The Residential Comprehensive Energy Education program is operated under subcontract by the National Energy Education Development (NEED). Launched in 1980, NEED promotes student understanding of the scientific, economic, and environmental impacts of energy. The program is currently available in 50 states, and the U.S. territories. NEED operates on a limited basis internationally. The program has provided comprehensive information on all energy sources and issues, with an emphasis on efficiency and conservation in both the residential and institutional market. State standards-based Energy curriculum and hands-on kits, emphasizing inquiry science and the application of energy knowledge, are provided to teachers for use in their classrooms. Teachers can utilize the kits and curriculum over many years. In addition, Home Energy Efficiency Kits are delivered to families to install energy efficiency measures and to record energy savings. All students that participated in the curriculum are eligible for the Home Energy Efficiency kits. Energy Workshops are designed to provide educators (teaching grades K-12) with the content knowledge and process skills to return to their classrooms and communities, energize and educate their students and provide outreach to families and to conduct energy education programs that assist families in implementing behavioral changes that reduce energy consumption.

The Kentucky NEED Project has been active in the Commonwealth's schools for 14 years. Kentucky NEED delivers curriculum, teacher training, and school support services to local schools. In addition, Kentucky NEED manages the overall implementation for the Duke Energy Kentucky program and works with individual schools, teachers, and students to gain the maximum impact for the program. Kentucky NEED has received numerous accolades for its support of energy efficiency and conservation in local schools, for its support of Energy Star's Change the World Campaign, and for the integration of a student/family approach to conservation education. Overall, the program has reached teachers and students across the service territory. In 2009-10, three teacher workshops were held in Northern Kentucky reaching 86 teachers who teach 9,326 students.

Due to efforts of the Kentucky NEED Project, energy and facility managers with the Kenton County School District implemented a voluntary program that garnered national recognition for their energy management plans - incorporating student energy teams and classroom energy education. This led to the construction of a Leadership in Energy and Environmental Design (LEED) certified school building and the design and construction of additional high performance schools in the county and elsewhere in the Commonwealth. Kenton County's latest project is the new Turkey Foot Middle School, designed to be a net-zero energy school with the installation of the required number of solar panels and other energy conservation and efficiency features. NEED Curriculum is being implemented at the school and supports a STEM (Science, Technology, Engineering and Mathematics) focus. In addition to providing safe and effective learning environments that are more efficient and cost effective than traditional schools, these schools are also designed as 'learning laboratories.' Students work with architects, engineers and contractors to learn about the buildings before, during and after construction. Once in the building, the students on the energy team lead tours of the buildings for visitors and community members.

Kentucky NEED's partnership with the Kentucky Department for Energy Development and Independence (DEDI) has expanded to include funds to hire four regional energy education coordinators to assist with the facilitation of energy programming and the development of student energy teams across the Commonwealth. The coordinator for Northern Kentucky works with schools, teachers and students requesting energy education and curriculum integration assistance. The DEDI partnership continues to promote high performance school construction and the implementation of low cost measures as a foundation for larger, more cost-saving projects. The program addresses: (1) building energy efficiency improvements through retrofits financed by use of energy saving performance contracts (ESPC) and improved new construction; (2) school transportation practices; (3) educational programs; (4) procurement practices; and (5) linkages between school facilities and activities within the surrounding community. This program is now called Kentucky High Performance Sustainable Schools Program and the training programs for it are supported by Kentucky NEED. During the 2008-09 school year, this program expanded the partnership to include KEEPS (KY Energy Efficiency Program for Schools) and Kentucky School Plant Management Association (KSPMA). These workshops focused more on energy saving operations and maintenance opportunities that included establishing school energy teams consisting of maintenance/custodial staff, teacher advisor(s) and student energy teams. The student teams are encouraged to focus their efforts on developing an energy plan for their schools to encourage energy saving behaviors by all members of the school community. In July of 2010, a fifth partner joined the team. DEDI provided funding for the Kentucky School Energy Managers Project (SEMP) that provides support for school districts to hire energy managers. Kentucky NEED works closely with the energy managers across the state, to assist in the development of student energy teams, and integration of energy curriculum that addresses energy behaviors in their schools in partnership with the district level energy team.

To improve and better document the energy savings associated with the program, a change was made in 2004 adding a new survey instrument for use in the classroom and a Saving Energy at Home and School Kit that serves as a companion to the Home Energy Efficiency Kits delivered to families in the Duke Energy Kentucky service area. A curriculum was developed, piloted, improved with teacher feedback, and delivered to schools participating in the Duke Energy sponsored program. In addition to the curriculum content delivered, the program includes household surveys, to allow teachers and families to encourage and implement in-home adoption of energy efficiency measures. Data collected from the home survey is provided to Duke Energy annually. Setting metrics and collecting the data has shown that the measures included in the Home Energy Efficiency Kits are being installed and utilized. The Home Energy Efficiency Kits include CFL bulbs, low-flow shower heads, faucet aerators, water temperature gauge, outlet insulation pads, and a flow meter bag. During the 2009-10 school year, 488 kits were distributed.

In partnership with DEDI, NEED continues to promote school participation in ENERGY STAR's Change the World, Start with Energy Star campaign. To support, recognize and encourage student energy leadership, Kentucky NEED hosts the annual Kentucky NEED Youth Awards for Energy Achievement Luncheon in Frankfort each May, honoring teams of students who have successfully planned and facilitated energy projects in their schools and communities. One hundred twenty-seven students participated on these teams, reaching 7,148 students and 40,664 community members. Students and teachers from Phillip Sharp Middle School, Tichenor Middle School, and Summit View Elementary School attended the 30th Annual NEED Youth Awards for Energy Achievement to represent Kentucky's success.

Program 4: Program Administration, Development, & Evaluation

This program is responsible for designing, implementing and capturing costs related to the administration, evaluation and support of the Collaborative and Duke Energy Kentucky's overall DSM effort. Program development funds are utilized for the redesign of programs and for the development of new programs, or program enhancements, such as the refrigerator replacement portion of the Residential Conservation and Energy Education program. Evaluation funds are used for cost effectiveness analysis and evaluation, impact evaluation and process evaluation of program activities. Funds going forward will be used to monitor, evaluate and analyze these programs to improve cost effectiveness and program design. Therefore, Duke Energy Kentucky expects, and has planned for, the continuation of funding for this program to cover evaluation study costs for the current year's activities as well as future evaluations. Duke Energy Kentucky strives to optimize and balance the use of these program funds, such that program development and redesign continues, that all programs are analyzed every year for cost effectiveness, and that programs are generally afforded the opportunity for a full scale impact evaluation and energy savings assessment once every two to three years. Duke Energy Kentucky believes that it is unnecessary to spend funds on impact evaluations every year for all programs, but also understands that all programs must undergo impact evaluation scrutiny and review at least once every two to three years.

Program 5: Payment Plus

Over the past few years, the Residential Collaborative and Duke Energy Kentucky have tested an innovative home energy assistance program called Payment Plus. The program was designed to impact participants' behavior (*e.g.*, encourage meeting utility bill payments as well as eliminate arrearages) and to generate energy conservation impacts. That program was extended with the Commission's Order in Case No. 2004-00389 to include both the early participants and new participants each year.

The program has three parts:

1. Energy & Budget Counseling – to help customers understand how to control their energy usage and how to manage their household bills, a combined education/counseling approach is used.
2. Weatherization – participants in this program are required to have their homes weatherized as part of the normal Residential Conservation and Energy Education (low-income weatherization) program unless weatherized in past program years.
3. Bill Assistance – to provide an incentive for these customers to participate in the education and weatherization, and to help them get control of their bills, payment assistance credits are provided to each customer when they complete the other aspects of the program. The credits are: $200 for participating in the EE counseling, $150 for participating in the budgeting counseling, and $150 to participate in the Residential Conservation and Energy Education program. If all of the requirements are completed, a household could receive up to a total of $500. This allows for approximately 125 homes to participate per year as some customers do not complete all three steps or have already had the weatherization completed prior to the program.

This program is offered over six winter months per year, starting in October. Customers are tracked and the energy savings is evaluated after two years to see if customer energy consumption dropped, and whether changes in bill paying habits have occurred. Previous participants' energy savings have been evaluated and compared to a control group of customers with similar arrearages and incomes. This analysis is the longest-running impact and process evaluation in the country looking at both energy savings and arrearages from a single program. From this analysis, there is long-term evidence that the program is effective at reducing energy usage and arrearages. Given the positive evaluation results, the Collaborative proposed and the Commission approved in May 2007 continuation of the program at a cost of $150,000 per year through 2009; this was extended through December 31, 2012, in Case No. 2009-00444. Follow-up educational reinforcement took place for all participants beginning in the fall of 2007. For the filing period beginning in the fall of 2009, 90 participants attended energy education counseling, 66 participants attended budget counseling and 44 participant homes have been weatherized.

Program 6: Power Manager®

The purpose of the Power Manager® program is to reduce demand by controlling residential air conditioning usage during peak demand conditions in the summer months. It is available to residential customers with central air conditioning. Duke Energy Kentucky attaches a load control device to the outdoor unit of a customer's air conditioner. This enables Duke Energy Kentucky to cycle the customer's air conditioner off and on when the load on Duke Energy Kentucky's system reaches peak levels.

Customers participating in this program receive a one-time enrollment incentive and a bill credit for each Power Manager® event. Customers who select Option A, which cycles their air conditioner to achieve a 1 kW reduction in load, receive a $25 credit at installation. Customers selecting Option B, which cycles their air conditioner to achieve a 1.5 kW load reduction, receive a $35 credit at installation. For both options, a Variable Daily Event Incentive based upon marginal costs is also provided for each cycling event.

The load control devices have built-in safe guards to prevent the "short cycling" of the air-conditioning system. The air-conditioning system will always run the minimum amount of time required by the manufacturer. The cycling simply causes the air-conditioning system to run less, which is no different than what it does on milder days. Additionally, the indoor fan will continue to run and circulate air during the cycling event.

Given our supply position in Kentucky, the Company did not actively promote Power Manager® to our customers during the July 2009 through June 2010 fiscal year. Without directly marketing the program, 86 customers enrolled in Power Manager® during the past fiscal year. For these new participants and for replacements of existing load control devices, we continue to use switches manufactured by Cooper Power Systems/Cannon Technologies. With the Cannon devices we are achieving an average reduction of .99 kW per switch.

During the past fiscal year we continued quality control testing, consisting of a general inspection of the air conditioner and switch installation, and retrieval of the event performance data stored in the switch. Over 2400 devices were checked; and of these, slightly over 500 were found to be not performing properly and were replaced. This ongoing quality management effort provides assurance that the program is operating as intended, and at a load reduction level that continues to be cost effective. These quality assurance efforts will continue.

Ongoing measurement and verification is conducted through a sample of Power Manager® customers with switches that record hourly run-time of the air conditioner unit and with load research interval meters that measure the household kWh usage in 15-minute intervals. Annual operability studies are used to measure the performance of Power Manager® load control devices in Kentucky. While the 2010 study was focused on Cannon switches, we will update our 2009 study of CSE devices in 2011. Switch performance is assessed by analysis of scan data showing the contents of key switch registers. An initial collection of scan data for the full sample was completed in July, 2010. Before final operability results are determined, there will be a second scan data collection at the end of the control season for some devices in the sample.

Program 7: ENERGY STAR Products

As approved in Order 2004-00389, the ENERGY STAR Products program provides incentives and market support through manufacturer and retailer partners to build market share and usage of ENERGY STAR products, particularly CFLs. Incentives to buyers, along with educational materials, stimulate demand for the products, and make it easier for partners to participate. The program targets residential customers' purchase of specified ENERGY STAR technologies at local retail stores.

Price continues to be the primary market barrier to CFL adoption. While the average price of CFL's has dropped slightly in the last 12 months, the cost of a CFL is generally much higher than traditional incandescent alternatives (*e.g.*, \$2.50 vs. \$.75). This cost difference is more exaggerated for specialty CFLs such as "can lights," 3-way bulbs and outdoor lights.

In the fall of 2009, Duke Energy Kentucky partnered with GE offering customers discount coupon offers. Mailing discount coupons directly to customers' homes allows Duke Energy Kentucky to reach customers beyond those customers who had previously participated in prior promotions.

The GE campaign kicked-off on September 10th, 2009, with coupons valid through December 31st, 2009. The goal of this campaign was to encourage more customers to participate, by presenting an offer that allowed those customers to use the coupons at the retailer of their choice, further expanding the program's reach. Working closely with our manufacturing partner, GE, Duke Energy Kentucky identified the most popular package size that gave the greatest variety to customers, while at the same time encouraged customers to purchase and install multiple CFL bulbs. Duke Energy Kentucky customers received a coupon mailer with four coupons each offering $3 off the purchase of two GE CFL 2-packs. In addition to having retailer options, this promotional offer gave customers the chance to purchase the wattage and bulb style of their choice, at a discount.

Program 8: Energy Efficiency Website, On-line Energy Assessment

As approved in Order 2004-00389, Duke Energy Kentucky is authorized to offer opportunities for customers to assess their energy usage and obtain recommendations for more efficient use of energy in their homes at the Duke Energy Kentucky website. This Kentucky program fits suitably into our new multi-state program design now referred to as our Residential Energy Assessment Program.

Duke Energy Kentucky customers visiting their Online Services account at duke-energy.com are encouraged to take a short Energy Efficiency survey (EE survey). Participants receive an immediate, online, printable Energy Efficiency report (EE report) and are also sent a package of six, free Compact Fluorescent Light (CFL) bulbs. The customized online EE report gives the customer information on the home's energy usage, providing the customer energy tips and information regarding how they use energy and what simple, low cost/no cost measures can be undertaken to lower their energy bill. The report also contains information on month-to-month comparisons of energy usage, a trend chart showing usage of electric and/or gas by kWh/ccf by month, a disaggregation of how the customer uses electricity and/or gas in the most important appliances, and customized energy tips based on the customer's answers to questions in the survey.

After several months of revising the Duke Energy Kentucky website to include new content from our energy efficiency website vendor, ACLARA™, the online EE Survey and free CFL offer was rolled out to Duke Energy Kentucky customers in March of 2010. From March through June, 314 Duke Energy Kentucky customers completed the online EE Survey and received a pack of six CFLs.

Participants in this program respond to an online offer that appears when they visit their Online Services account. The offer shows up for any Online Services customer who has not yet participated in this program. It should be noted that another Duke Energy program called the Personalized Energy Report (PER) is similar, but involves a mailed offer instead of an online offer (see Program 9).

Program 9: Personalized Energy Report (PER)

The PER program provides Duke Energy Kentucky customers with a customized Energy Efficiency report aimed at helping them better manage their energy costs. This is similar to the online EE Survey and CFL offer described in Program 8, except that this program utilizes a mailed offer for those who do not have computer access or choose not to use the online programs. The EE report and six CFLs are mailed to those customers who mail in a completed survey.

This program targets single family residential customers in the Duke Energy Kentucky market that have not received measures through the Home Energy House Call home audit or Residential Conservation & Energy Education programs within the last three years. Duke Energy Kentucky has been working with ACLARA™ software to coordinate the customer's energy efficiency experiences between the online offer, described under the Online Energy Assessment program above, and this mailed version, or "paper" offer. (Marketing activities under this program were suspended in 2008 and 2009 pending the reorganization and harmonization of the website with the new vendor ACLARA™. The PER program rolled out in May 2010 to Kentucky customers.)

To receive the paper version of the EE report (*i.e.*, the PER), a customer completes an EE survey that generates the PER. The EE survey stimulates the customer to think about how they use energy, and then the mailed report provides them with tools and information to lower their energy costs. The program commences with a letter to the customer, offering the PER if they would return the enclosed short, energy survey about their home. The survey asks very simple questions such as age of home, number of occupants, types of fuel used to cool, heat, and cook. Once the survey is returned, the information is used to generate a customized PER. The PER contains the same information as the EE survey described under the Online Energy Assessment program above, but is mailed to the home instead of viewed online. To lower mailing costs, customers who receive the mailed survey and PER offer are encouraged to visit Duke Energy Kentucky's website instead and fill in the same survey online instead of returning the paper survey and waiting for the mailed PER report. The online report is immediately available in a printable format. The online option saves costs in the long run, and provides a source for customers to reprint their report, if desired. All participants also receive a free package of six CFLs. The bulbs are two different sizes to accommodate different lighting needs in the home.

The Kentucky PER offer was mailed to 53,000 customers on May 25, 2010. Results for this campaign will be divided into two reporting periods. For the period of July 2009 through June 2010, there were 7,010 participants. Between July 1, 2010 and November 1, 2010, there were an additional 3664 participants for a campaign total of 10,374. This represents an outstanding response rate of about 20%. Of the 10,374 participants, 1926 or about 19% of all responses chose to use the online survey and view the online report instead of requesting the mailed report.

Program 10: C&I High Efficiency Incentive (Business and Schools)

The Commission's Order in Case No. 2004-00389 approved a program for Duke Energy Kentucky to provide incentives to small commercial and industrial customers to install high efficiency equipment in applications involving new construction, retrofit, and replacement of failed equipment. The approval included a portfolio of nearly 100 lighting, HVAC, Motors/Pumps/VFDs, Process, Food Services equipment and Energy Star Commercial clothes washers.

Program operations began in October of 2005. However, the portfolio was downsized to some degree until a similar expanded program was approved in either Indiana or Ohio to gain efficiencies in administration costs. Results in the first 9 month of program rollout were beyond expectation. Thirty-six applications were processed totaling $313,350 in incentives. Duke Energy Kentucky attributed this to a pent-up demand in the marketplace and the installation of the High Bay T-8 and T-5 lighting fixtures. In response to the market, the following adjustments were made to the program in order to serve more customers and remain cost effective:

- Incentives for T-8, T-5 and High Bay fixtures were no longer eligible in a "new construction" application, only retrofit applications. The new construction market was utilizing these technologies as the standard so incentives were no longer necessary.
- The incentive levels for T-8 High Bay and T-5 High Output High Bay fixtures were adjusted to align with price changes in the market.
- A cap of $50,000 per facility per calendar year was implemented in an effort to serve more customers.
- A reservation system was instituted during the proposal stage, to ensure that customers will receive their incentives once the project is complete.

In April of 2007, the program funds had exhausted again and Duke had to carryover $81,248 in incentives for customers until the new fiscal year budget became available. On May 15, 2007, the Commission approved Duke Energy Kentucky's application to increase funding for 100% with an additional $451,885 for a Kentucky Schools program.

Duke Energy Kentucky continues to contract with WECC to provide the back office support for implementation of this program. This program is jointly implemented with the Duke Energy Indiana and Duke Energy Ohio territories to reduce administrative costs and leverage promotion. WECC, located in Madison, Wisconsin, has 25 years experience in delivering programs similar to this. They have an office in the Midwest and are able to support Duke Energy programs in this region. The primary delivery of the program is through the existing market channels, equipment providers and contractors. WECC had an existing network of relationships with Vendors and Trade

Ally organizations in Duke Energy Kentucky's service territory that have helped promote the sale of energy efficient equipment during these difficult economic times.

During the reporting period July 2009 through June 2010, the Kentucky Smart Saver program continued to be successful. Eighty customers received $411,606 in incentives.

Schools: assessments, prescriptive and custom efforts

The Schools program, approved on May 15, 2007, provides schools funding for facility assessments, custom and prescriptive measures rebates and EE education from the NEED organization.

Between July 2009 and June 2010, two school districts took advantage of incentives through the custom incentive application. Kenton County School District received $118,307 in incentives for a total of 24 energy efficiency projects at 15 different facilities, and Ft. Thomas School District received $3,800 in incentives for a project at Highland Middle School.

Duke Energy Kentucky Schools Custom Program was well-received. It provided an additional funding source for EE measures that are not included in Duke Energy Kentucky's portfolio of Prescriptive Incentives. The program helped motivate additional custom EE within schools.

Upon receiving a Custom Incentive application, Duke Energy Kentucky reviews the application and performs a technical evaluation as necessary to validate energy savings. Measures submitted by the customer are then modeled in DSMore to determine an acceptable incentive that ensures cost effectiveness to the program overall, given the energy savings, and improves a customer's payback to move them to invest in energy efficiency. Evaluation follow-up and review includes application review, site visits and/or onsite metering and verification of baseline energy consumption, customer interviews, and/or use of loggers/sub-meters. As use of Custom Incentives increases, Duke Energy Kentucky will evaluate applications and determine if additional measures can be included in the Prescriptive Incentives program. Including measures that repeatedly arise in Custom Incentive applications in the Prescriptive Incentives makes planning and applying for measure incentives easier for customers.

Program 11: PowerShare®

PowerShare® is the brand name given to Duke Energy Kentucky's Peak Load Management Program (Rider PLM, Peak Load Management Program KY.P.S.C. Electric No. 2, Sheet No. 77). The PLM Program is voluntary and offers customers the opportunity to reduce their electric costs by managing their electric usage during the Company's peak load periods. Customers and the Company will enter into a service agreement under this Rider, specifying the terms and conditions under which the customer agrees to reduce usage. There are two product options offered for PowerShare® called CallOption® and QuoteOption®:

- CallOption®
  - A customer served under a CallOption® product agrees, upon notification by the Company, to reduce its demand.
  - Each time the Company exercises its option under the agreement, the Company will provide the customer a credit for the energy reduced.
  - There are two types of events.
    - Economic events are primarily implemented to capture savings for customers and not necessarily for reliability concerns. Participants are not required to curtail during economic events. However, if participants do not curtail, they must pay a market based price for the energy not curtailed. This is called "buy through energy."
    - Emergency events are implemented due to reliability concerns. Participants are required to curtail during emergency events.
  - If available, the customer may elect to buy through the reduction at a market-based price. The buy through option is not always available as specified in the 2010 PowerShare® Agreements. During Midwest ISO declared emergency events, customers are not provided the option to buy through.
  - In addition to the energy credit, customers on the CallOption® will receive an option premium credit.

- For 2010, there are three different enrollment choices for customers to select between. All three choices require curtailment availability for up to five emergency events per Midwest ISO requirements for capacity participation. Economic events vary among the choices. Customers can select exposure of zero, five, or ten economic events.
- Only customers able to provide a minimum of 100 kW load response qualify for CallOption®.

- QuoteOption®
  - Under the QuoteOption® products, the customer and the Company agree that when the average wholesale market price for energy during the notification period is greater than a pre-determined strike price, the Company may notify the customer of a QuoteOption® event and provide a Price Quote to the customer for each event hour.
  - The customer will decide whether to reduce demand during the event period. If they decide to do so, the customer will notify the Company and provide an estimate of the customer's projected load reduction.
  - Each time the Company exercises the option, the Company will provide the customer an energy credit.
  - There is no option premium for the QuoteOption® product since customer load reductions are voluntary.
  - Only customers able to provide a minimum of 100 kW load response qualify for QuoteOption®.

Rider PLM was approved pursuant as part of the settlement agreement in Case No. 2006-00172. In the Commission's Order in Case No. 2006-00426, approval was given to include the PowerShare® program within the DSM programs.

PowerShare® 2010

Duke Energy Kentucky's customer participation goal for 2010 was to retain all customers that currently participate and to promote customer migration to the CallOption® program. As seen in the table below, QuoteOption participation decreased this year. Due to a switch in system vendors, it became necessary for QuoteOption customers to enroll in the Energy Profiler Online product. This product carries a small monthly fee. The small monthly fee is the primary reason customers left the program.

The table below compares account participation levels for 2009 and 2010, as well as MW's enrolled in the program. The MW values are Duke Energy Kentucky's estimate of the curtailment capability across the summer of 2010.

Table C-2 Kentucky PowerShare Participation Update

Kentucky PowerShare® Participation Update					
Enrolled Customers					
CallOption			QuoteOption		
2009	2010	Change	2009	2010	Change
10	**12**	**2**	**33**	**23**	**-10**
Summer Curtailment Capability (MW's)*					
CallOption			QuoteOption		
2009	2010	Change	2009	2010	Change
12.2	**13.6**	**1.4**	**6.1**	**6.3**	**0.2**

*Capability for QuoteOption is 80% of enrolled load curtailment estimate

CallOption numbers reported are adjusted for losses

During the summer of 2010, there were five CallOption® events and no QuoteOption® events. All CallOption events were economic events. There were no CallOption emergency events. The table below summarizes event participation.[5]

Table C-3 Duke Energy Kentucky PowerShare CallOption Economic Events

Duke Energy Kentucky - PowerShare® CallOption Economic Events						
Summer 2010 Activity						
Date	Event Hours	Participants	Participants Reducing Load Partially or Fully	Average Hourly Load Reduction Available - Before Losses	Average Hourly Load Reduction - Before Losses	Average Hourly Load Reduction - After Losses
7/7/2010	Noon to 8 PM	12	6	15.4	2.7	2.8
7/23/2010	Noon to 8 PM	12	9	15.4	1.1	1.2
8/10/2010	Noon to 8 PM	12	7	16.6	1.7	1.8
8/12/2010	Noon to 8 PM	12	5	16.5	1.1	1.1
8/13/2010	Noon to 8 PM	12	5	16.1	1.6	1.7

For PowerShare® 2010, there were several significant changes implemented as anticipated last year. These changes included:

- An earlier start to the enrollment period to accommodate Duke Energy Kentucky and Midwest ISO requirements;

[5] "PowerShare CallOption participants are presented with the option to "buy-through" economic events since system reliability is not a concern during economic events. As can be seen above, several customers took full advantage or partial advantage of this option given that actual curtailment amounts are less than the available amounts. For energy consumed under this buy-through option, customers pay a market based price for energy. Buy-through is not available during emergency events."

- The new CallOption 0/5 added to customer participation choices; and
- Annual testing requirements for participants using a generator as the source of their load curtailment.

For PowerShare® 2011, Duke Energy Kentucky currently is not anticipating any changes from the 2010 program structure. It should be noted that Duke Energy Kentucky is currently researching the changes that may be needed to the programs in order to transition from MISO to PJM starting on January 1, 2012. Changes to the PowerShare® program structure for this transition are not fully known at this time but will be detailed in next year's filing.

4. PROPOSED DSM PRODUCTS

In addition to the above approved DSM products, Duke Energy Kentucky is currently seeking approval of a new Product, Residential Smart Saver.

Proposed Program 12: Residential Smart Saver

Duke Energy Kentucky, along with the support of the Residential Collaborative (with the exception of the Office of the Attorney General, who abstained) is seeking authority from the Commission for Duke Energy Kentucky to implement a new Residential Energy Efficiency/ DSM program, the Residential Smart Saver, and to recover costs including net lost revenues and incentives related to this program. The Company has requested that the program be implemented for an initial three year term through December 31, 2013. The objective of this program is to offer additional incentives to qualifying residential customers in support of the Kentucky Housing Corporation's Kentucky Home Performance conservation program.

Program details are as follows:

a. **Background:** The Kentucky Housing Corporation, KHC, is launching a statewide single family energy conservation program called Kentucky Home Performance (KYHP). KYHP takes a whole-house approach to improve energy efficiency, health, and comfort. This state-wide program targets households at or above 200% of poverty in order to initiate energy conservation and to stimulate the residential home improvement market.

KHC aims to increase whole-house energy efficiency and renewable energy improvements to residences across the Commonwealth.

b. **<u>Partnership:</u>** Duke Energy Kentucky has partnered with KHC to support the establishment and growth of KYHP within the Company's Kentucky service area. The new program, Residential Smart Saver, will be complimentary to KYHP by offering incentives on a suite of energy home improvements that support the objectives of KYHP. The program encourages the customer to install the improvement measures that are not only right for their home, but also provide the greatest opportunity for energy savings.

c. **<u>Measures:</u>** Improvement measures in the program are the envelope improvements of attic insulation and air sealing, duct sealing and tune-ups for central air conditioning and heat pump equipment. For those customers who need more than an equipment tune-up, the program offers incentives for the installation of high efficiency heat pumps or air conditioners in both existing homes and new construction.

d. **<u>Target Market:</u>** Eligible customers are those Duke Energy Kentucky customers living in owner occupied residences. Duke Energy Kentucky will offer incentives to customers when one or more of the qualifying energy efficient improvements are installed in their home by a qualified contractor. While customers are encouraged to participate in the KYHP program, it is not a requirement in order to receive the Duke Energy Kentucky Residential Smart Saver incentive.

e. **<u>Incentives:</u>** Incentives are paid for the installation of qualifying and defined energy home improvement measures. The table below outlines the incentive structure:

Table C-4 Incentive Structure

Qualifying Improvement Measure	Customer Incentive	Contractor Incentive
Attic Insulation and air sealing	$250	
Duct Sealing	$100	
Heat Pump Tune Up	$50	
Air Conditioner Tune Up	$50	
High Efficiency Heat Pump *	$200	$100
High Efficiency Central Air Conditioner*	$200	$100

*In new homes the builder can apply to receive the entire $300 incentive

f. **<u>Expected Savings/ Benefits</u>:** Projected energy savings and demand reductions are estimated based on the anticipated number of installations of various types of energy efficient measures. The estimated effects of T& D losses are included and Free riders are included. The projected total program benefits at the end of the three-year period are an energy savings of 5,532,146 KWh.

g. **<u>Implementation Plan</u>:** Duke Energy Kentucky will employ third party companies to administrator (Program Administrator) the Residential Smart Saver program. The Program Administrator Company is responsible for working with "Trade Allies" such as heating contractors or insulation companies who are in direct contact with the residential customers. Once the customer decides to purchase a qualifying improvement measure, an incentive application is prepared by the "Trade Ally" and sent to the Program Administrator where it is processed and verified. The verification includes the confirmation that the applicant is a Duke Energy Kentucky customer and that the improvement installed is a part of the program. Once this is complete, the incentive payments are made by the Program Administrator to the customer and contractor as applicable. A third party vendor, Customer Link, is employed by Duke Energy Kentucky to handle customer calls on the program, answering the questions and or directing the caller to the proper person.

h. Annual budget:

	Projected Program Costs	Lost Revenues	Shared Savings	Energy Impacts
2011	$448,520	$533,499	$53,822	971,550 kWh
2012	$747,007	$1,134,748	$89,641	2,203,503 kWh
2013	$731,609	$1,138,283	$87,793	2,357,093 kWh

Table C-5 Response to Section 8 (3)(e)4

[redacted]

[redacted]

Table C-6 Response to Section 8 (3)(e)5

[redacted]

[redacted]

[redacted]

[redacted]

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Appendix D – Recommended Plan

APPENDIX D – RECOMMENDED PLAN
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Response to Section 8(3)(b)(12)a-c, e and g Capacity Factors, Average Heat Rates, Average Variable, and Total Production Costs

The required information is contained in the tables that follow, in redacted form. Duke Energy Kentucky considers this information to be trade secrets and confidential and competitive information. It will be made available to appropriate parties for viewing at Duke Energy offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order.

Figure 8.(3).(b)(12)a-c, e, g

[redacted]

[redacted]

Figure 8.(3).(b)(12)a-c, e, g

[redacted]

[redacted]

Figure 8.(3).(b)(12)a-c, e, g

[redacted]

[redacted]

Figure 8.(3).(b)(12)a-c, e, g

[redacted]

Figure 8.(3).(b)(12)a-c, e, g

[redacted]

[redacted]

Figure 8.(3).(b)(12)a-c, e, g

[redacted]

[redacted]

Figure 8.(3).(b)(12)a-c, e, g

[redacted]

Figure 8.(3).(b)(12)a-c, e, g

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Figure 8.(3).(b)(12)a-c, e, g

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Figure 8.(3).(b)(12)a-c, e, g

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Figure 8.(3).(b)(12)a-c, e, g

[redacted]

[redacted]

Figure 8.(3).(b)(12)a-c, e, g

[redacted]

[redacted]

[redacted]

Figure 8.(3).(b)(12)a-c, e, g

[redacted]

[redacted]

[redacted]

Figure 8.(3).(b)(12)a-c, e, g

[redacted]

[redacted]

[redacted]

Section 8(3)(b)(12)d, f Estimated Capital Costs of Planned Units, Escalation Rates

The required information is contained in the following table, in redacted form. As discussed in Volume I, Chapter 5, most of the specific technology parameters used in the screening process were based on information taken from several sources. EPRI considers its information to be trade secrets and proprietary and confidential. Duke Energy Kentucky and its consultants consider cost estimates provided by consultants to be confidential and competitive information. Duke Energy also considers its internal estimates to be confidential and competitive information. The information will be made available to appropriate parties for viewing at Duke Energy offices during normal business hours upon execution of appropriate confidentiality agreements or protective orders.

8(3)b)(12)d, f

[redacted]

[redacted]

Section 9(1) Present Value Revenue Requirements

The 2011 Present Value Revenue Requirement (PVRR) for the 2011 IRP is $[redacted] The effective after-tax discount rate used was 7.5%.

The modeling does not include the existing rate base (generation, transmission, or distribution).

The PVRR analysis is utilized to compare alternative resource options and portfolios. The impacts to customer rates were not determined as part of this analysis.

Duke Energy Kentucky considers the PVRR to be confidential and competitive information. It will be made available to appropriate parties for viewing at Duke Energy offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order.

Section 9(3) Yearly Revenue Requirements

The projections of yearly revenue requirements are shown on the following page, in redacted form. Duke Energy Kentucky considers these projections to be trade secrets and confidential and competitive information. They will be made available to appropriate parties for viewing at Duke Energy offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order.

Section 9(3)

[redacted]

[redacted]

Section 8(4)(b) and (c) Energy by Primary Fuel Type, Energy from Utility Purchases, and Energy from Non-utility Purchases

The following pages contain the information required.

Section 8(4)(b)
Duke Energy-Kentucky
Forecast Annual Energy (GWh)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 Energy Requirements	4,225	4,296	4,393	4,498	4,565	4,595	4,628	4,659	4,692	4,727	4,763	4,798	4,834	4,859	4,888	4,921	4,958	5,002	5,043	5,085	5,136

2 Energy By Fuel Type	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	4,599	4,040	4,560	3,673	3,341	2,923	3,377	3,245	3,378	3,254	3,376	3,244	3,377	3,254	3,377	3,244	3,377	3,254	3,378	3,246	3,378
Gas	195	283	158	272	758	1,212	1,020	1,068	1,032	1,082	1,019	1,061	1,012	1,049	984	1,032	1,100	1,145	1,084	1,124	1,200
Renewables	0	0	0	0	0	36	106	125	125	145	231	234	251	271	287	287	287	287	287	287	286

3 Firm Purchases From Other Utilities	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

4 Firm Purchases From Non-Utility	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
5 Reductions or Increases In Energy																					
DR	0	0	0	(0)	0	0	0	0	(0)	0	0	0	(0)	0	0	0	0	0	0	0	(0)
EE	(5)	(18)	(35)	(54)	(74)	(105)	(124)	(144)	(164)	(184)	(203)	(223)	(243)	(263)	(282)	(302)	(322)	(342)	(362)	(381)	(385)
Total	(5)	(18)	(35)	(54)	(74)	(105)	(124)	(144)	(164)	(184)	(203)	(223)	(243)	(263)	(282)	(302)	(322)	(342)	(362)	(381)	(385)

Net (Sales)/Purchaes	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Market	(575)	(45)	(360)	500	392	319	0	77	(7)	62	(67)	37	(49)	23	(42)	57	(128)	(27)	(68)	47	(114)

Section 8(4)(c)
Duke Energy-Kentucky
Total Energy Input and Total Generation by Primary Fuel Type (GWh)

Coal	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Energy (GWh)	4,599	4,040	4,560	3,673	3,341	2,923	3,377	3,245	3,378	3,254	3,376	3,244	3,377	3,254	3,377	3,244	3,377	3,254	3,378	3,246	3,378
Total (000 Tons)	2,094	1,848	2,054	1,689	1,531	1,339	1,547	1,486	1,547	1,490	1,546	1,486	1,547	1,490	1,546	1,486	1,547	1,490	1,547	1,486	1,547
(000 MBTUs) Consumed	48,084	42,273	47,700	39,166	35,215	30,791	35,574	34,181	35,579	34,277	35,565	34,173	35,573	34,278	35,569	34,169	35,576	34,280	35,581	34,186	35,583

Gas	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Energy (GWh)	195	71	91	95	90	104	95	106	111	130	125	134	125	129	138	155	143	151	147	132	130
Total (MCF)	3,035	4,963	2,876	5,055	7,557	12,290	9,590	10,231	9,631	10,394	9,491	10,131	9,440	10,016	9,166	9,906	9,494	10,180	9,479	10,081	10,041
(000 MBTUs) Consumed	3,114	5,092	2,951	5,186	7,754	12,610	9,839	10,497	9,882	10,664	9,737	10,394	9,685	10,277	9,404	10,163	9,741	10,445	9,725	10,343	10,302

Biomass	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Energy (GWh)	0	0	0	0	0	33	33	50	50	66	83	82	99	116	132	132	132	132	132	132	132
(000 MBTUs) Consumed	0	0	0	0	0	427	425	638	638	853	1,064	1,063	1,277	1,493	1,702	1,702	1,703	1,707	1,702	1,702	1,701

Wind and Solar	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Energy (GWh)	0	0	0	0	0	3	73	76	76	79	149	152	152	155	155	155	155	155	155	155	155

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Appendix E – Response to 2008 IRP Staff Comments

APPENDIX E – RESPONSE TO 2008 IRP STAFF COMMENTS

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Section 11(4) Response to Staff's Comments and Recommendations

The following pages contain the responses to the Staff Report of the Duke Energy Kentucky 2008 IRP.

2008 IRP Commission Response #1:

Report on how the change in base temperature for its Heating Degree Days (HDD) calculations and its use of a 10-year period in developing HDD and Cooling Degree Days (CDD) "normals" have impacted how its actual energy and demand levels compare to its forecasted levels.

This recommendation requests a comparison of the actual load to two forecasts.

- A forecast prepared using the weather variables included in the 2008 load forecast, HDD computed with a base temperature of 59 degrees and a ten year average for normal weather for HDD and CDD; and
- A forecast that uses HDD with a base of 65 degrees and a thirty year average for normal weather for HDD and CDD.

To assess this, the Company collected information on the actual energy usage of residential, commercial, industrial, and OPA customer classes for the years 2009 and 2010 and compared those loads to each of the forecasts for the sum of those classes. The table below summarizes the results of those comparisons. This shows the percent difference between the actual load and each of the forecasts. This reveals that for these two projected years (2009 and 2010), use of HDD with a base of 59 degrees and a ten year basis for normal weather produced forecasts closer to actual than a forecast using HDD with a base of 65 degrees along with a thirty year basis for normal weather.

	2008 Forecast Comparison of Actual to Forecast	
	Base 59 HDD 10 Year Normals	Base 65 HDD 30 Year Normals
2009	5.9%	7.5%
2010	0.8%	2.4%

2008 IRP Commission Response #2:

Examine and report on the potential impact of future environmental requirements (specifically carbon capture and sequestration and other green house gas mitigation requirements) and how these issues are incorporated into present forecasts and/or will be incorporated into future forecasts.

We are not currently incorporating carbon capture and sequestration or other green house gas mitigation requirements in the 2011 Duke Energy Kentucky load forecast. However, the load forecast includes the projected cost of CO_2 allowances and its impact on electric prices. As noted in Appendix B, electric prices are one of the variables used to forecast load.

2008 IRP Commission Response #3:

Report on the need, if any, to incorporate impacts occurring due to the expanding role of the Midwest ISOr into future forecasts

Duke Energy Kentucky does not believe that the expanding role of Midwest ISO has a material impact on future Duke Energy Kentucky load forecasts. However, the Company has complied with the process of providing a peak load forecast each month and comparing the weather normal actual load against the forecast. This comparison is performed to assess whether or not the forecast complied with the Midwest ISO one standard deviation variance requirement. The Duke Energy load forecasting team is currently participating in the Midwest ISO Load Forecasting Methodology Review meetings to stay informed on new or developing reporting requirements and best practices.

Duke Energy Kentucky will operate within PJM consistent with its intention to transfer the Duke Energy Kentucky transmission assets from the Midwest ISO to the PJM regional transmission organization effective January 1, 2012. Thus the IRP was developed assuming that Duke Energy Kentucky operates under the PJM organization as of the effective date.

2008 IRP Commission Response #4:

In the next IRP, Duke Kentucky should specifically discuss the existence of any cogeneration within its service territories and the consideration given to cogeneration in the resource plan.

Customers make cogeneration decisions based on their particular economic situations, so Duke Energy Kentucky does not attempt to forecast specific Megawatt levels of cogeneration activity in its service area. Cogeneration facilities built to affect customer energy and demand served by the utility are captured in the load forecast. Cogeneration built to provide supply to the electric network represents additional regional supply capability. As purchase contracts are signed, the resulting energy and capacity supply will be reflected in future plans.

An assessment was made of the Combined Heat and Power (CHP) potential in the Duke Energy Kentucky service territory. In this assessment, all potential customers were identified that use more than 1000 MWhr/yr, and then identified industries that are best suited for CHP. A summary of these industries are listed below.

SIC	Industry	% CHP Potential (US. Wide Average)
20	Food and Kindred Products	6.1%
26	Paper and Allied Products	29.9%
27	Printing, Publishing and Allied Industries	0.1%
28	Chemicals and Allied Products	16.3%
29	Petroleum Refining and Related Industries	25.4%
30	Rubber and Miscellaneous Plastic Products	0.3%
32	Nonmetallic Mineral Products	0.9%
33	Primary Metal Industries	2.5%
34	Fabricated Metal Products, Except Machinery & Transport Equipment	0.6%
35	Industrial and Commercial Machinery and Computer Equipment	0.4%
37	Transportation Equipment	0.1%
49	Waste Water Treatment Facilities	10.6%
80	Healthcare Facilities	10.6%
82	Colleges and Universities	10.6%

The United States CHP generation percentage of total electricity consumption with each industry was then compared to the 2010 consumption (KWh) of these Kentucky customers. The CHP potential was assessed assuming that a CHP plant would need to run at least 5000 hours/yr. Based on the results of this analysis the Duke Energy Kentucky CHP potential is 9.15 MW.

2008 IRP Commission Response #5:

Duke Kentucky should specifically identify and describe the net metering equipment and systems installed. A detailed discussion of the manner in which such resources are considered in its next IRP should also be provided.

Duke Energy Kentucky's net metering customers have a total connected capacity of 0.47 MW. All of this capacity is supplied by inverter-based photovoltaic (PV) generation. Of the 17 customers that are net metered, 11 are single-family residential, two are multi-unit residential, two are schools, and two are commercial businesses. The largest PV system, at 0.39 MW, is at one of the schools. Except for the other school, all the other customers have generating capacities less than 10 kW.

In 2010, nine Duke Energy Kentucky customers installed photovoltaic systems, which is more than twice the total number of Duke Energy Kentucky customers who installed systems in the years 2006-2009. It is expected that in 2011, figures will be in line with those of 2010.

2008 IRP Commission Response #6:

Duke Kentucky should provide a detailed discussion of the consideration given to distributed generation in its next IRP.

This was addressed in the System Optimizer Portfolio Analysis in Chapter 8. To simulate the potential impact on the long term resource plan of increased distributive generation, the amount of solar was increased from 0.25% to 1% of retail sales. Based on a review of other states that have implemented a Renewable Energy Portfolio Standard (REPS), the 1% target represents an aggressive but reasonable expectation of what could be achieved. The inclusion of an increased solar requirement delayed the long term capacity need from 2027 to 2028, and advantages CT generation over CC generation in that timeframe.

2008 IRP Commission Response #7:

Duke Kentucky should provide a specific discussion of the improvements to and more efficient utilization of transmission and distribution facilities as required by 807 KAR section 8 (2)(a). This information should be provided for the past three years and should address Duke Kentucky's plans for the next three years.

The response to this comment is addressed in Appendix F Section 3.

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The Duke Energy Kentucky 2011 Integrated Resource Plan

July 1, 2011

Appendix F – Transmission & Distribution

APPENDIX F – TRANSMISSION & DISTRIBUTION
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1. PREFACE

This Appendix contains information that addresses the Transmission and Distribution requirements of 807 KAR 5:058 relative to the Duke Energy Kentucky 2011 Integrated Resource Plan.

The information included in this Appendix discusses a plan summary and resource assessment and acquisition plan relative to Transmission and Distribution assets in Duke Energy Kentucky.

2. SECTION 5 PLAN SUMMARY RESPONSES

Response to 5. (4) Planned Resource Acquisition Summary – Transmission System

There are no currently in-progress or planned transmission system projects affecting any Duke Energy Kentucky transmission facilities that are intended to provide or are associated with the provision of additional resources. No new interconnections with other utilities are planned.

3. SECTION 8. RESOURCE ASSESSMENT AND ACQUISITION PLAN

a. Response to 8. (2) (a) Options Considered for Inclusion

Changes to the Duke Energy Kentucky transmission and distribution systems are based on meeting planning criteria, which are intended to provide reliable system performance in a cost-effective manner. Loss reduction is a secondary goal, which may be considered, when appropriate, in deciding between various alternatives, which serve the primary purpose of maintaining system performance. In general, projects, which are solely intended to reduce losses, are not cost-effective. The costs for such projects are high, and the loss impacts are too small to materially affect the resource plan.

The following improvements were made to the Duke Energy Kentucky transmission system in 2008, 2009 and 2010 for the purposes of increasing capacity and/or reliability:

2008

No transmission system improvements were implemented.

2009

No transmission system improvements were implemented.

2010

No transmission system improvements were implemented.

The following transmission system improvements are planned for 2011, 2012, and 2013:

2011

No transmission system improvements are planned.

2012

No transmission system improvements are planned.

2013

No transmission system improvements are planned.

The following improvements were made to the Duke Energy Kentucky distribution system in 2008, 2009 and 2010 for the purposes of increasing capacity and/or reliability:

2008

Dayton Substation – Install new 138-12 kV, 22.4 MVA transformer

Dayton 41, 42 & 43 – Establish three new 12 kV distribution feeders

White Tower Substation – Install new 69-12 kV, 10.5 MVA transformer

White Tower 42 – Establish new 12 kV distribution feeder

Covington Substation – Install new 69-12 kV, 22.4 MVA transformer

Covington 42 & 43 – Establish two new 12 kV distribution feeders

2009

Hebron Substation – Install new 138-12 kV, 22.4 MVA transformer

Hebron 43, 44 & 45 – Establish three new 12 kV distribution feeders

2010

Kentucky University Substation – Install new 138-12 kV, 22.4 MVA transformer

Kentucky University 43 – Establish new 12 kV distribution feeder

The following distribution system improvements are planned for 2011, 2012, and 2013:

2011

2012

Kentucky University 45 – Establish new 12 kV distribution feeder.

2013

2. Response to 8. (3) (a) Map of Facilities

Maps and transmission line thermal capacity table are considered critical energy infrastructure information (CEII). The information will be provided to the KyPSC Staff under seal, not to be released to the general public.

Table F-1 2009-2010 Electric Property Comparison Table

THE DUKE ENERGY OHIO & DUKE ENERGY KENTUCKY CORPORATIONS
CINCINNATI, OHIO

2009 - 2010 ELECTRIC PROPERTY COMPARISON

JANUARY 2011

	NUMBER OF SUBSTATIONS		KVA CAPACITY	
THE DUKE ENERGY OHIO CORP.	2009	2010	2009	2010
DISTRIBUTION SUBSTATIONS	214	214	6,851,449	6,873,849
TRANSMISSION SUBSTATIONS	31	31	14,369,773	14,369,773
CCD AND CD SUBSTATIONS (NOTE 1)			2,850,167	2,850,167
	245	245		
TOTAL DE-OHIO SUBSTATIONS (NOTE 2)	227	227	24,071,389	24,093,789
THE DUKE ENERGY KENTUCKY CORP.				
DISTRIBUTION SUBSTATIONS	36	36	1,177,128	1,199,528
TRANSMISSION SUBSTATIONS	4	4	600,000	600,000
	40	40		
TOTAL DE-KENTUCKY SUBSTATIONS (NOTE 3)	37	37	1,777,128	1,799,528
TOTAL SUBSTATIONS AND KVA CAPACITY (NOTE 4)	262	262	25,848,517	25,893,317
NET INCREASE IN KVA CAPACITY				44,800

NOTES:

1. THIS TOTAL REPRESENTS DE-OHIO'S SHARE OF THE JOINTLY OWNED GENERATOR STEP-UP TRANSFORMER CAPACITY OF W. C. BECKJORD TB 6, MIAMI FORT TB 7 AND TB 8, ZIMMER TB 1LP AND TB 1HP, CONESVILLE TB 4, STUART TB 1, TB 2, TB 3, AND TB4, AND STUART SUBSTATION TRANSFORMERS TB 7 AND TB 16.

2. THIS NUMBER REPRESENTS THE TOTAL COUNT OF INDIVIDUAL DE-OHIO SUBSTATIONS AND DIFFERS FROM THE ABOVE SUM BY THE NUMBER OF DUAL PURPOSE SUBSTATIONS (16) WHICH WERE COUNTED TWICE PLUS TWO JOINTLY OWNED SUBSTATIONS COUNTED TWICE.

3. THIS NUMBER REPRESENTS THE TOTAL COUNT OF INDIVIDUAL DE-KENTUCKY SUBSTATIONS AND DIFFERS FROM THE ABOVE SUM BY THE NUMBER OF DUAL PURPOSE SUBSTATIONS (3) WHICH WERE COUNTED TWICE.

4. THERE ARE TWO SUBSTATIONS WITH DE-OHIO AND DE-KENTUCKY CAPACITY. THEREFORE, THE TOTAL NUMBER OF SUBSTATIONS IS TWO LESS THAN THE SUM OF THE INDIVIDUAL COMPANY TOTALS.

5. THE DE-OHIO DISTRIBUTION SUBSTATION COUNT REMAINED THE SAME, REFLECTING NO ADDITIONS, NO REMOVAL, AND NO RECLASSIFICATION.
THE DE-OHIO TRANSMISSION SUBSTATION COUNT REMAINED THE SAME, REFLECTING NO ADDITIONS, NO REMOVALS, NO RECLASSIFICATION.

6. THE DE-KENTUCKY DISTRIBUTION SUBSTATION COUNT REMAINED THE SAME, REFLECTING NO ADDITION, NO REMOVAL, NO RECLASSIFICATIONS.
THE DE-KENTUCKY TRANSMISSION SUBSTATION COUNT REMAINED THE SAME, REFLECTING NO ADDITIONS, NO REMOVALS, NO RECLASSIFICATIONS.

Table F-2 2010 Transmission FERC Form 1

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	69KV TRANSMISSION POOL		69.00	69.00	POLE	102.14	3.04	
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	102.14	3.04	

Name of Respondent Duke Energy Kentucky, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
	1,094,542	11,020,302	12,114,844	81,675	299,358	1,934,700	2,315,733	1
								2
								3
								4
								5
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								31
								32
								33
								34
								35
	1,094,542	11,020,302	12,114,844	81,675	299,358	1,934,700	2,315,733	36

Table F-3 2010 Distribution FERC Form 1

THE UNION LIGHT, HEAT AND POWER COMPANY	An Original	DEC. 31, 2007

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j) and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and account affected in respondent's books of accounts. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In kV) (Note) Primary (c)	Secondary (d)	Tertiary (e)
1	ALEXANDRIA SOUTH-CAMPBELL CO.	UNATTENDED - D	69.0	13.2	0.0
2	AUGUSTINE-COVINGTON, KY.	UNATTENDED - D	138.0	13.2	0.0
3	BEAVER-BOONE CO.	UNATTENDED - D	69.0	13.2	0.0
4	BELLEVUE-CAMPBELL CO.	UNATTENDED - D	138.0	13.2	0.0
5	BLACKWELL - GRANT CO	UNATTENDED - T	138.0	69.0	0.0
6	BUFFINGTON-KENTON CO.	UNATTENDED - T & D	138.0	69.0	13.2
7	CLARYVILLE-CAMPBELL CO.	UNATTENDED - D	69.0	13.2	0.0
8	COLD SPRING-KENTON CO.	UNATTENDED - D	138.0	13.2	0.0
9	CONSTANCE-KENTON CO.	UNATTENDED - D	138.0	13.2	0.0
10	COVINGTON - KENTON CO.	UNATTENDED - D	69.0	13.2	0.0
11	CRITTENDEN- GRANT CO.	UNATTENDED - D	69.0	13.2	0.0
12	CRESCENT-KENTON CO.	UNATTENDED - D	138.0	13.2	0.0
13	DAYTON - CAMPBELL CO.	UNATTENDED - D	138.0	13.2	0.0
14	DECOURSEY-KENTON CO.	UNATTENDED - D	69.0	13.2	0.0
15	DIXIE-BOONE CO.	UNATTENDED - D	69.0	13.2	0.0
16	DONALDSON-KENTON CO.	UNATTENDED - D	138.0	13.2	0.0
17	DRY RIDGE - GRANT CO.	UNATTENDED - D	69.0	13.2	0.0
18	EMPIRE - BOONE CO.	UNATTENDED - D	69.0	13.2	0.0
19	FLORENCE-BOONE CO.	UNATTENDED - D	138.0	13.2	0.0
20	GRANT-GRANT CO.	UNATTENDED - D	69.0	13.2	0.0
21	HANDS-KENTON CO.	UNATTENDED - D	138.0	13.2	0.0
22	HEBRON- BOONE CO.	UNATTENDED - D	138.0	13.2	0.0
23	KENTON-KENTON CO.	UNATTENDED - T & D	138.0	13.2	0.0
24	KY.UNIVERSITY-CAMP. CO.	UNATTENDED - D	138.0	13.2	0.0
25	LIMABURG-BOONE CO.	UNATTENDED - D	69.0	13.2	0.0
26	LONGBRANCH-BOONE CO.	UNATTENDED - D	138.0	13.2	0.0
27	MARSHALL-CAMPBELL CO.	UNATTENDED - D	69.0	13.2	0.0
28	MT ZION - BOONE CO.	UNATTENDED - D	138.0	13.2	0.0
29	OAKBROOK-BOONE CO	UNATTENDED - D	69.0	13.2	0.0
30	RICHWOOD-BOONE CO.	UNATTENDED - D	69.0	13.2	0.0
31	THOMAS MORE - KENTON CO	UNATTENDED - D	69.0	13.2	0.0
32	VERONA - KENTON CO.	UNATTENDED - D	69.0	13.2	0.0
33	VILLA-CRESTVIEW HLS.,KY.	UNATTENDED - D	69.0	13.2	0.0
34	WHITE TOWER-KENTON CO.	UNATTENDED - D	69.0	13.2	0.0
35	WILDER-WILDER, KY.	UNATTENDED - T & D	138.0	69.0	13.2
36	YORK-NEWPORT, KY.	UNATTENDED - D	138.0	13.2	0.0
37	1 STATION UNDER 10 MVA	UNATTENDED - D	69.0	4.3	0.0
38	Summary of Listed Stations Above (By Function)				
39	not including Commonly Owned Substations				
40					
41					
42					

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SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)	Line No.
10.500	1	0				1
72.400	2	0				2
21.000	2	0				3
44.800	2	0				4
150.000	1	0				5
328.400	5	0				6
31.500	3	0				7
32.900	2	0				8
44.800	2	0				9
22.400	1	0				10
21.000	2	0				11
44.800	2	0				12
22.400	1	0				13
10.500	1	0				14
42.400	2	0				15
44.800	2	0				16
10.500	1	0				17
24.500	2	0				18
67.200	3	0				19
21.000	2	0				20
44.800	2	0				21
44.800	2	0				22
164.578	3	0				23
44.800	2	0				24
31.500	3	0				25
22.400	1	0				26
10.500	1	0				27
22.400	1	0				28
22.400	1	0				29
31.500	3	0				30
22.400	1	0				31
10.500	1	0				
44.800	2	0				32
21.000	2	0				33
167.200	3	0				34
22.400	1	0				35
3.750	1	0				36
						37
						38
						39
						40
						41
						42

THE UNION LIGHT, HEAT AND POWER COMPANY | An Original | DEC. 31, 2007

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j) and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and account affected in respondent's books of accounts. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (in kV) (Note) Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)	Line No.
1	UNATTENDED - T & D					660.178						1
2	UNATTENDED - D					989.350						2
3	UNATTENDED - T					150.000						3
4	ATTENDED - T & D					0.000						4
5	ATTENDED - D					0.000						5
6	ATTENDED - T					0.000						6
7						1799.528						7
8												8
9	Note: The voltages reported in columns (c), (d) and (e) are the highest and lowest in the substation but not necessarily											9
10	on the same transformer. Column (g) represents the number of three phase transformers											10
11	and/or transformer banks rather than the number of individual transformers.											11

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July 1, 2011

Appendix G – Index to Duke Energy Kentucky 2011 IRP

APPENDIX G – INDEX TO DUKE ENERGY KENTUCKY 2011 IRP
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Index to Duke Energy Kentucky 2011 IRP	242

Response to Section 4(2): Identification of Individuals Responsible for Preparation of the Plan

The following individuals are responsible for the preparation of this filing:

Name	Department
Robert A. McMurry	Integrated Resource Planning
Thomas J. Wiles	Market Analytics
Jose I. Merino	Load Forecasting
Edward O. Abbott	Generation Operations Support
Tammie C. Smith	Analytical Engineering
Jeff O. Turner	Transmission Planning
Tony J. Platz	Distribution Planning
Christopher D. Hallman/Michael W. Stroben	Environmental
Owen A. Smith	Renewables

Index to Duke Energy Kentucky 2011 IRP

Section	Location in DE-Kentucky 2011 IRP Document
Section 1	No Reponse Required
Section 2	No Reponse Required
Section 3	No Reponse Required
Section 4.(1)	No Reponse Required
Section 4.(2)	Appendix G; Response to Section 4.2
Section 5.(1)	Chapter 1, Section A
Section 5.(2)	Chapter 1, Section A, B; Chapter 2, Section B, C, D Chapter 8, Section B
Section 5.(3)	Chapter 3, Section B; Figures 3-1 through 3-3 Appendix B, Section 6; Figures B-1 Part 1 through B-12 Part 2
Section 5.(4)	Chapter 4 Chapter 5, Section B, C, D, E, F Chapter 8 Appendix C, Section F Appendix F
Section 5.(5)	Chapter 1, Chapter 8
Section 5.(6)	Chapter 1, Section A Chapter 8, Section B
Section 6	Chapter 1, Section B; Table 1-A Chapter 8, Section B; Figures 8-1 and 8-2 Appendix B; Figures B-3 through B-6 Appendix D
Section 7.(1)a Section 7.(1)b Section 7.(1)c Section 7.(1)d Section 7.(1)e Section 7.(1)f Section 7.(1)g	Appendix B; Figures B-1 Parts 1&2 through B-2 Parts 1& 2 Appendix B; Figures B-11 Parts 1&2 through B-12 Parts 1&2
Section 7.(2)a	Appendix B; Response to 7.(2)a
Section 7.(2)b	Appendix B; Response to 7.(2)b&c
Section 7.(2)c	Appendix B; Response to 7.(2)b&c
Section 7.(2)d	Chapter 5, Sections C, D, E
Section 7.(2)e	Chapter 5, Sections C, D, E
Section 7.(2)f	Appendix B Figures B-1 Parts 1&2 through B-2 Parts 1&2
Section 7.(2)g	Appendix C, Section 3; Chapter 4, Table 4-A
Section 7.(2)h	Chapter 3, Figures 3-1 through 3-3
Section 7.(3)	Chapter 8, Figure 8-7
Section 7.(4)a	Appendix B; Figures B-1 Part 1 through B-2 Part 2
Section 7.(4)b	Appendix B; Figures B-4 through B-6
Section 7.(4)c	Appendix B; Figures 8-9 Part 1 through 8-12 Part 2
Section 7.(4)d	Chapter 3, Figures 3-1 through 3-3; Chapter 4, Table 4-A
Section 7.(4)e	Appendix B Figures 8-7 & 8-8
Section 7.(5)(a)1	WAIVER RECEIVED
Section 7.(5)(a)2	WAIVER RECEIVED
Section 7.(5)(b)1	WAIVER RECEIVED
Section 7.(5)(b)2	WAIVER RECEIVED
Section 7.(7)a	Appendix B Response to Section 7.(7)a
Section 7.(7)b	Appendix B, Sections 2 & 3
Section 7.(7)c	Appendix B, Sections 3, 4, 5
Section 7.(7)d	Appendix B Figures 8-7 & 8-8
Section 7.(7)(e)1 Section 7.(7)(e)2 Section 7.(7)(e)3	Appendix B, Sections 2 through 6
Section 7.(7)(e)4	Appendix C, Section 4
Section 7.(7)(e)4(f)	Appendix B, Sections 4 through 6
Section 7.(7)(e)4(g)	Appendix B, Section 4 and 6

Section	Location in DE-Kentucky 2011 IRP Document
Section 8.(2)a	Appendix F
Section 8.(2)b	Appendix C, Section 4
Section 8.(2)c	Chapter 1, Chapter 5, Section F, Chapter 8
Section 8.(2)d	Chapter 1 Chapter 8 Appendix E
Section 8.(3)a	Appendix F; Response to Section 8.(3)a (under seal)
Section 8.(3)(b)1	Appendix D
Section 8.(3)(b)2	Appendix D
Section 8.(3)(b)3	Appendix D
Section 8.(3)(b)4	Appendix D
Section 8.(3)(b)5	Appendix D
Section 8.(3)(b)6	Appendix D
Section 8.(3)(b)7	Appendix D
Section 8.(3)(b)8	Appendix D
Section 8.(3)(b)9	Appendix D
Section 8.(3)(b)10	Appendix D
Section 8.(3)(b)11	Appendix D
Section 8.(3)(b)12a.	Appendix D
Section 8.(3)(b)12b.	Appendix D
Section 8.(3)(b)12c.	Appendix D
Section 8.(3)(b)12d.	Appendix D
Section 8.(3)(b)12e.	Appendix D
Section 8.(3)(b)12f.	Appendix D
Section 8.(3)(b)12g.	Appendix D
Section 8.(3)c	Chapter 8 Appendix D
Section 8.(3)d	Chapter 8 Appendix D
Section 8.(3)(e)1	Appendix C
Section 8.(3)(e)2	Appendix C
Section 8.(3)(e)3	Appendix C
Section 8.(3)(e)4	Appendix C; Table C-5
Section 8.(3)(e)5	Appendix C; Table C-6
Section 8.(4)	Appendix C
Section 8.(4)(a)1	Chapter 8, Figure 8-1; Appendix D
Section 8.(4)(a)2	Chapter 8, Figure 8-1; Appendix D
Section 8.(4)(a)3	Chapter 8, Figure 8-1; Appendix D
Section 8.(4)(a)4	Chapter 8, Figure 8-1; Appendix D
Section 8.(4)(a)5	Chapter 8, Figure 8-1; Appendix D
Section 8.(4)(a)6	Chapter 4 Chapter 8, Figure 8-1
Section 8.(4)(a)7	Chapter 8, Figure 8-1
Section 8.(4)(a)8	Chapter 8, Figure 8-1
Section 8.(4)(a)9	Chapter 8, Figure 8-1
Section 8.(4)(a)10	Chapter 8, Figure 8-1
Section 8.(4)(a)11	Chapter 8, Figure 8-1
Section 8.(4)(b)1	Appendix D, Response to 8(4)b and c
Section 8.(4)(b)2	Appendix D, Response to 8(4)b and c
Section 8.(4)(b)3	Appendix D, Response to 8(4)b and c
Section 8.(4)(b)4	Appendix D, Response to 8(4)b and c
Section 8.(4)(b)5	Appendix D, Response to 8(4)b and c
Section 8.(4)c	Appendix D, Response to 8(4)b and c
Section 8.(5)(a)	Chapter 8, Section B
Section 8.(5)(b)	Chapter 8, Section B
Section 8.(5)(c)	Chapter 8, Section B; Appendix D
Section 8.(5)(d)	Chapter 8, Section B
Section 8.(5)(e)	Chapter 5, Section F
Section 8.(5)(f)	Chapter 6 Chapter 8, Section B
Section 8.(5)(g)	Chapter 8, Section B

Section	Location in DE-Kentucky 2011 IRP Document
Section 9.(1)	Appendix D, Response to Section 9(1)
Section 9.(2)	Appendix D, Response to Section 9(1)
Section 9.(3)	Appendix D, Response to Section 9(3)
Section 9.(4)	Appendix D, Response to Section 9(1)
Section 10.	No Response Required
Section 11.(1)	No Response Required
Section 11.(2)	No Response Required
Section 11.(3)	No Response Required
Section 11.(4)	Appendix E