DUKE ENERGY.

Mailing Address:
139 East Fourth Street
1212 Main / P.O. Box 960
Cincinnati, Ohio 45202

o: 513-287-4315
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**VIA OVERNIGHT MAIL DELIVERY**

July 30, 2014

RECEIVED

JUL 31 2014

PUBLIC SERVICE
COMMISSION

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

Re: Duke Energy Kentucky 2014 Integrated Resource Plan

Dear Mr. Derouen:

Enclosed please find an original and ten copies of the Public Version of Duke Energy Kentucky's 2014 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 2014 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 Ryan /AMF

Kristen Ryan
Senior Paralegal
kristen.ryan@duke-energy.com

cc: Jennifer Hans (w/enclosures)
Florence Tandy (w/enclosures)
Carl Melcher (w/enclosures)

573581

**James P. Henning**
President
Duke Energy Kentucky

139 E. $4^{th}$ Street
Room 1409-M
Cincinnati, OH 45202

513.287.4078
jim.henning@duke-energy.com

July 30, 2014

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

RE: Duke Energy Kentucky 2014 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 2014 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 2014 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 areas such as: 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, "Appendix 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 Scott Park, Integrated Resource Planning, at the offices of Duke Energy located at 400 South Tryon Street, Charlotte, NC 28202.

Yours truly,

James P. Henning

Duke Energy Kentucky, Inc.

2014 INTEGRATED RESOURCE PLAN

CERTIFICATE OF SERVICE

The undersigned states that he is the President of Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.; that he 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:

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

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.

James P. Henning
President, Duke Energy Ohio and Kentucky

7/30/2014
Date

## NOTICE OF FILING

Please take notice, that pursuant to 807 KAR 5:058, Section 1(2), Duke Energy Kentucky, Inc., has, this 30th day of July 2014, filed a copy of the Duke Energy Kentucky 2014 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 31 2014

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. 2014- |

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 13, respectfully requests the Commission to classify and protect certain information that is contained in Duke Energy Kentucky's 2014 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, and projected capacity and resource alternative capital costs; (3) supply side screening curves and resource evaluations; (4) third party owned and licensed modeling tools; and (5) 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 various compliance and other O&M expenses, capital costs, power market prices, and projected capacity cost - 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 competitor's 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 2014 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 power market prices, coal prices, gas prices, and oil prices developed by an independent third party, Energy Ventures Analysis, Inc., subject to confidentiality restrictions. Burns and McDonnell provided operating specifications and costs for potential future generating units, and Moody's Analytics provided economic forecasts, both subject to confidentiality agreements. 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 PJM Interconnection L.L.C., (PJM) 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. Duke Energy Kentucky does not object to limited disclosure of the confidential information described herein, pursuant to an acceptable protective agreement, the Attorney General or other intervenors with a legitimate interest in reviewing the same for the purpose of participating in this case.

6. This information was, and remains, integral to Duke Energy Kentucky's effective execution of business decisions. And such information is generally regarded as confidential or proprietary. Indeed, as the Kentucky Supreme Court has found, "information concerning the inner workings of a corporation is 'generally accepted as confidential or

proprietary.'" *Hoy v. Kentucky Industrial Revitalization Authority*, Ky., 904 S.W.2d 766, 768 (Ky. 1995).

7. In accordance with the provisions of 807 KAR 5:001, Section 13(3), the Company is filing one copy of the Confidential Information separately under seal, and ten copies without the confidential information included.

8. Duke Energy Kentucky respectfully requests that the Confidential Information be withheld from public disclosure for a period of ten years. This will assure that the Confidential Information – if disclosed after that time – will no longer be commercially sensitive so as to likely impair the interests of the Company or its customers if publicly disclosed.

9. To the extent the Confidential information becomes generally available to the public, whether through filings required by other agencies or otherwise, Duke Energy Kentucky will notify the Commission and have its confidential status removed, pursuant to 807 KAR 5:001 Section 13(10)(a).

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)
Associate General Counsel
Amy B. Spiller (85309)
Deputy General Counsel
Duke Energy Business Services, LLC
139 East Fourth Street, 1303 Main
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e-mail:rocco.d'ascenzo@duke- energy.com
*Counsel for Duke Energy Kentucky, Inc.*

## 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 2014 Integrated Resource Plan was served on the following by overnight mail, this 30TH day of July 2014.

Rocco O. D'Ascenzo

Jennifer Hans
The Office of the Attorney General
Utility Intervention and Rate Division
1024 Capital Center Drive, Suite 200
Frankfort, Kentucky 40601

DUKE ENERGY.

*Kentucky*

# The Duke Energy Kentucky 2014 Integrated Resource Plan

## Public Version



## July 31, 2014

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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 138,000 customers in its approximate 300 square mile service territory. 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's resource planning process utilizes quantitative analysis and qualitative considerations to identify the best options to serve customers' future energy and capacity needs. Quantitative analysis provides insights into future risks and uncertainties associated with the load forecast, fuel and energy costs, and renewables. Qualitative considerations, such as fuel diversity, the Company's environmental profile, emerging environmental regulations, and the progress of emerging technologies, are also important factors. The result is an Integrated Resource Plan (IRP) that serves as an important tool to guide business decisions about customers' near-term and long-term energy needs. The overall objective of the IRP process is to develop a robust and reliable economic strategy for meeting the needs of customers in a very dynamic and uncertain environment.

Significant updates and changes in the Company's 2014 IRP from the 2011 IRP are:

<u>EXPECTED RETIREMENT OF MIAMI FORT 6</u>

The 2014 IRP is consistent with the 2011 IRP planning assumption that Miami Fort Unit 6 (Miami Fort 6) may need to retire by May 31, 2015, due primarily to the recently upheld Mercury and Air Toxic Standards (MATS) rule. The likely impact and cost of other emerging environmental regulations such as 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 (NAAQS), also contributed to the retirement decision. The possible retirement of

Miami Fort 6 results in a capacity need in 2015, which places the emphasis of this IRP on how to best meet this need.

UNCERTAINTY IN A CARBON CONSTRAINED FUTURE

Limits on the amount of carbon dioxide ($CO_2$) emissions have gained momentum with the release of proposed greenhouse gas (GHG) regulation *(Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units)* by the US Environmental Protection Agency (EPA) on June 2, 2014. While many of the details needed to make this regulation effective are to be determined, the proposed rule adds credibility to the analysis of a carbon constrained future. As a proxy for $CO_2$ regulation, this IRP assumes a price on carbon emission beginning in 2020. Given the short period of time between the release of the proposed rule and the submission date of this IRP, the IRP modeling and analysis continues to use this assumption.

PROPOSED GHG RULE

The impact of EPA's $CO_2$ regulation for existing Electric Utility Generating Units (EGUs) is unknown. The schedule in the proposed rule calls for EPA to finalize its rule by June 1, 2015. Then, the states will develop their own regulations to implement those emissions guidelines and submit those plans to EPA for approval. Duke Energy Kentucky will not know the specific regulatory requirements that will apply to its facilities until the State of Kentucky rule is completed and approved by EPA. The President directed EPA to require that states submit their rules to EPA for approval by June 30, 2016, but actual EPA approval is not likely to occur until sometime in 2017. In addition, those entities who propose to participate in multistate efforts do not have to file plans until 2018. Approval from EPA is set for no later than one year after plan submittal. In addition, the final rule and states' efforts to implement the rule are subject to court challenges. At this time, given the protracted timeframe and the potential for changes and challenges to the proposed rule, no prediction can be made about the final regulatory requirements. Duke Energy Kentucky has therefore not attempted to model this regulation, but believes that the $CO_2$ prices, energy efficiency (EE), and renewables assumptions used in our analyses can act as reasonable placeholders for the related costs that may be incurred.

LOAD FORECAST

The load forecast has changed slightly from the 2011 IRP, with peak demand forecasted to grow at an average annual rate of 0.6% vs 0.7% previously. The forecasted growth for net energy growth is expected to be the same at 0.6% per year. Detailed discussion of the load forecast is in Chapter 3 of this document.

FUEL PRICES

The coal and gas prices for both existing and new units were developed using a combination of observable forward market prices and long-term commodity price fundamentals. The Duke Energy Corporation (Duke Energy) long-term fundamental forecast is a proprietary product developed for Duke Energy by Energy Ventures Analysis (EVA), a leading energy consulting firm. The assumptions used in the development of the Duke Energy fundamental forecast were developed by EVA and Duke Energy in-house subject matter experts. In general, projections of long-term coal and gas prices have fallen 15% to 20% since the 2011 IRP.

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, 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.

The need for additional resources in 2015 is due primarily to the possibility of retirement of Miami Fort 6. Miami Fort 6 summer Maximum Net Dependable Capacity (MNDC) is 163 megawatts (MWs) and represents approximately 15% of the Duke Energy Kentucky generation resources. The base planning assumptions included in the 2014 resource plan include:

- Demand Side Management (DSM) – The energy efficiency (EE) DSM programs are projected to reduce energy consumption by approximately 378,000 MWh and 55 MW by 2029. The demand response (DR) DSM programs are projected to reduce peak load by approximately 39 MW by 2029. The direct load control program (Power Manager) is projected to reduce peak demand by 12 MW and the PowerShare® program another 26 MW by 2029. The total peak reduction across all programs is about 93 MW by 2029.

- Renewable Energy – Currently there is no Kentucky or federal renewable energy portfolio standard (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. This IRP assumes that 5% of retail sales would be met with renewable energy sources beginning in 2019, increasing 0.5% per year through 2028.
- Carbon Constrained Future – A $CO_2$ cap-and-trade regulatory construct was evaluated to assess the impact of potential climate change legislation.
- Reserve Margin – Using historical outage data, the reserve margin based on installed capacity, and the percentage that PJM Interconnection L.L.C. (PJM) is coincident with the Duke Energy Kentucky peak, the Reserve Margin used for this IRP is 13.7%.

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 2034. An overview of the recommended resource plan is outlined below and summarized on Table A.1.

Short Term: To meet the capacity and energy need created by the potential retirement of Miami Fort 6, the recommended replacement option is the installation or purchase of up to 195 MW of coal capacity in 2015.

Long Term: With the addition of up to 195 MW of the composite coal unit, renewable energy resources and DSM programs are sufficient to meet long term capacity and energy requirements. A portfolio was evaluated that considered an unspecified event that forced coal generation to retire in 2027. Depending upon the assumption regarding $CO_2$ regulation, combustion turbine (CT) generation was selected in the no carbon scenario and combined cycle (CC) generation was selected in the carbon scenario.

| Table 1-A Duke Energy Kentucky 2014 Resource Plan | | | | |
|---|---|---|---|---|
| Year | DSM[1] (EE & DR) | Unit Additions / Purchases / Retirements | Renewables (Wind / Solar / Biomass)[2] | Net Cumulative Additions |
| 2015 | -3 MW | Retire 163 MW MF6<br>Add 195 MW Coal | | 29 MW |
| 2016 | 6 MW | | | 34 MW |
| 2017 | 7 MW | | | 42 MW |
| 2018 | 6 MW | | | 48 MW |
| 2019 | 6 MW | | 5 MW | 59 MW |
| 2020 | 3 MW | | 5 MW | 68 MW |
| 2021 | 3 MW | | 5 MW | 77 MW |
| 2022 | 3 MW | | 5 MW | 85 MW |
| 2023 | 3 MW | | 7 MW | 95 MW |
| 2024 | 3 MW | | 3 MW | 102 MW |
| 2025 | 3 MW | | 5 MW | 111 MW |
| 2026 | 3 MW | | 2 MW | 116 MW |
| 2027 | 3 MW | | 5 MW | 125 MW |
| 2028 | -7 MW | | 5 MW | 124 MW |
| 2029 | 3 MW | | | 126 MW |
| 2030 | 3 MW | | | 129 MW |
| 2031 | 15 MW | | | 144 MW |
| 2032 | -10 MW | | | 134 MW |
| 2033 | 3 MW | | | 137 MW |
| 2034 | 0 MW | | 3 MW | 140 MW |

1. Incremental additions to 33 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 describes the objectives of, and the process used to develop, the 2014 Duke Energy Kentucky IRP. In the 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 define a robust strategy to furnish electric energy services to Duke Energy Kentucky customers in an adequate, efficient, and reasonable manner while considering the uncertainty of the current environment. The planning process must be dynamic and adaptable to changing conditions. The IRP represents the most robust and economic outcome based upon various assumptions and sensitivities. Due to current and future regulatory, economic, environmental and operating uncertainties, Duke Energy Kentucky performed sensitivity analyses to evaluate these. As circumstances change, the IRP will be monitored and adjusted as necessary and practical to reflect emerging information.

The 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 IRP presented in this filing are:

- Provide adequate, efficient, reasonable service that is economic 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 2014-2034, 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 potential retirement. This technique was used to focus on the near-term need while recognizing that as the environment changes, the IRP may be adjusted as needed. 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 $CO_2$ restriction impacts.

Two different scenarios were evaluated to assess the impact of potential $CO_2$ regulation. Detailed descriptions of these constructs are in Chapter 8.

1. $CO_2$ Regulation (Reference Case): $CO_2$ price curve beginning in 2020 represents the potential for future federal climate change legislation. The cost for emitting 1 ton of CO2 is assumed to be $17/ton in 2020, increasing to $53/ton in 2034. Given the timing of this IRP and the recently proposed rule for GHGs, this case serves as a proxy for the proposed rule. Once the proposed rule is better understood, the impacts of that regulation will be more specifically modeled.
2. No $CO_2$ regulation (No $CO_2$ Case): $CO_2$ emissions have no cost in this scenario. The total cost can be compared to the Reference Case as an approximation of the cost of carbon regulation.

The planning reserve margin used for the 2014 resource plan is 13.7%. The IRP models utilize the full capacity of the unit ratings to perform dispatch, so the reserve margin must be determined on that basis, 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 Duke Energy Ohio Kentucky (DEOK) Zone. DEOK is the PJM zone applicable to the Duke Energy Kentucky service territory. Based on future years the Forecast Pool Requirement is 9.2%.
2. The Forecast Pool Requirement based on UCAP is translated to a reserve margin by accounting for the Duke Energy Kentucky effective forced outage rate. The effective forced outage rate based on historical data is 8.3%, and the resulting reserve margin based on installed capacity is 19.1%. This is the reserve margin that would be applied to the Duke Energy Kentucky peak that is coincident with the PJM peak.

3. PJM's forecast assumes that the DEOK zone is 95.5% coincident with the PJM peak. Translating the 19.1% coincident reserve margin into a non-coincident reserve margin results in a reserve margin of 13.7% for planning purposes.

## D. PLANNING PROCESS

The development of the IRP 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. See Chapter 3.
- Identification of DSM options. See Chapter 4.
- Identification and economic screening for the cost-effectiveness of supply-side resource options. See Chapter 5.
- Integration of DSM, renewable, and supply-side options with the existing system and electric load forecast to develop potential resource portfolios that meet the reserve margin criteria. See Chapter 8.
- Performance of detailed modeling of potential resource portfolios to determine which one exhibits the lowest cost (lowest net present value of costs) to customers over a wide range of alternative futures. See Chapter 8.
- Evaluation of the ability of the selected resource portfolio to minimize price and reliability risks to customers. See 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 process 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 affiliated utilities, using the same methodology. Duke Energy Kentucky does not perform joint load forecasts with affiliated utility companies, and the forecast is prepared independently of the forecasting efforts of affiliated utilities. The load forecast is one of the most important parts of the IRP process. Customer demand provides the basis for the resources and plans chosen to supply the load.

## B. FORECAST METHODOLOGY

The general framework includes a national economic forecast, a service area economic forecast, and the electric load forecast. The national economic forecast predicts the 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. Moody's Analytics (Moody's), a national economic consulting firm, provides the national economic forecast. Similarly, the history and forecast of key economic and demographic concepts for the service area economy is obtained from Moody's. 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. Sales projections and electric system losses are combined to produce a net energy forecast.

Tables 3-A and 3-B show the forecasted annual growth rates before and after the impacts of EE programs. Both tables reflect peak load projections before the impacts of DR programs.

**TABLE 3-A**

**ELECTRIC ENERGY AND PEAK LOAD**

**FORECAST: ANNUAL GROWTH RATES BEFORE EE**

| | **2014 to 2034** |
|---|---|
| Residential MWh | 1.1% |
| Commercial MWh | 0.8% |
| Industrial MWh | 0.9% |
| Net Energy MWh | 0.9% |
| Summer Peak MW | 0.9% |
| Winter Peak MW | 0.8% |

**TABLE 3-B**

**ELECTRIC ENERGY AND PEAK LOAD**

**FORECAST: ANNUAL GROWTH RATES AFTER EE**

| | **2014 to 2034** |
|---|---|
| Residential MWh | 0.8% |
| Commercial MWh | 0.3% |
| Industrial MWh | 0.9% |
| Net Energy MWh | 0.6% |
| Summer Peak MW | 0.6% |
| Winter Peak MW | 0.7% |

Figure 3-1 depicts the energy forecast graph. Figure 3-2 depicts the summer and winter peak forecasts. These forecasts provide the starting point for the development of the IRP.

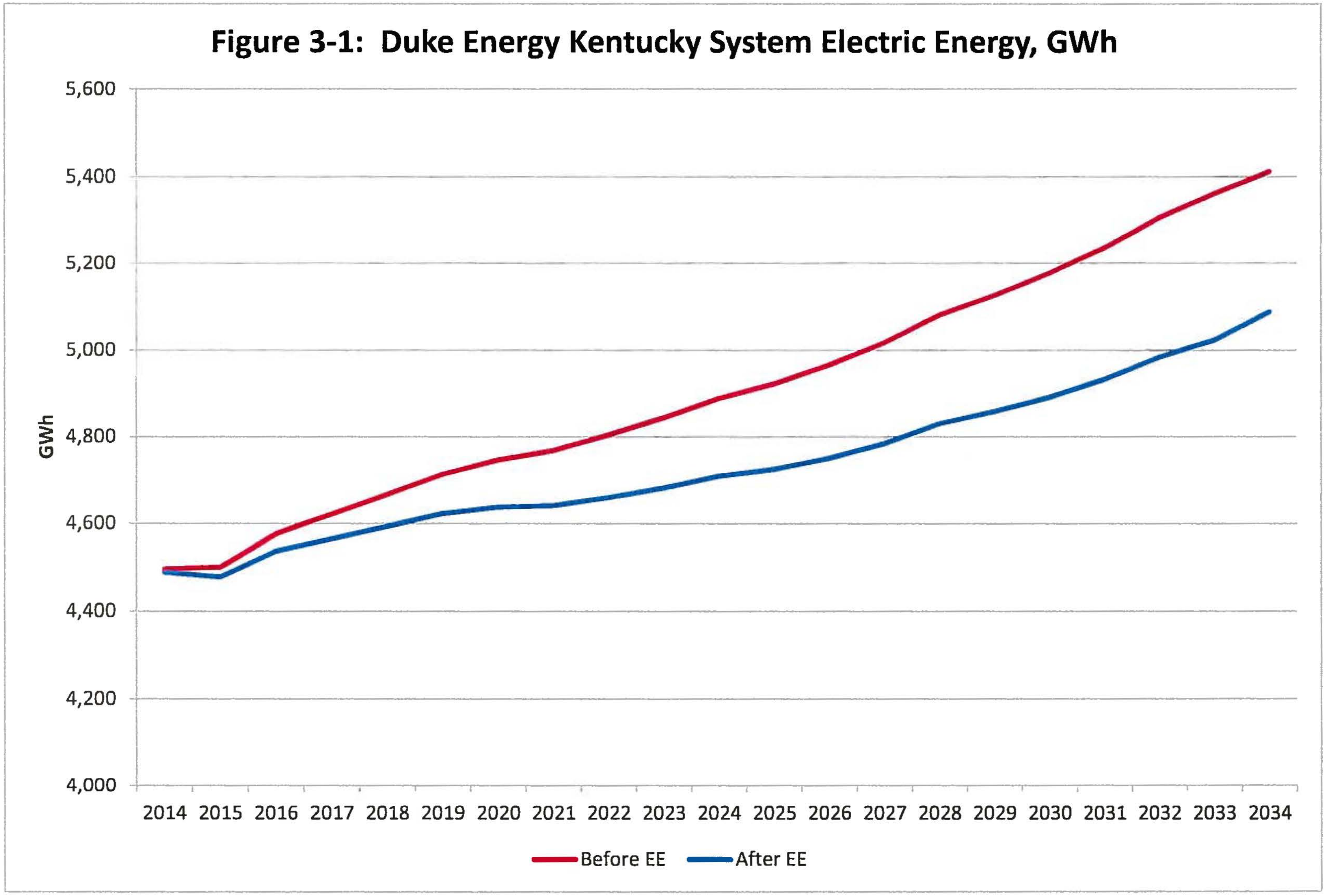


Figure 3-1: Duke Energy Kentucky System Electric Energy, GWh
5,600
5,400
5,200
5,000
4,800
4,600
4,400
4,200
4,000
GWh
2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034
Before EE
After EE

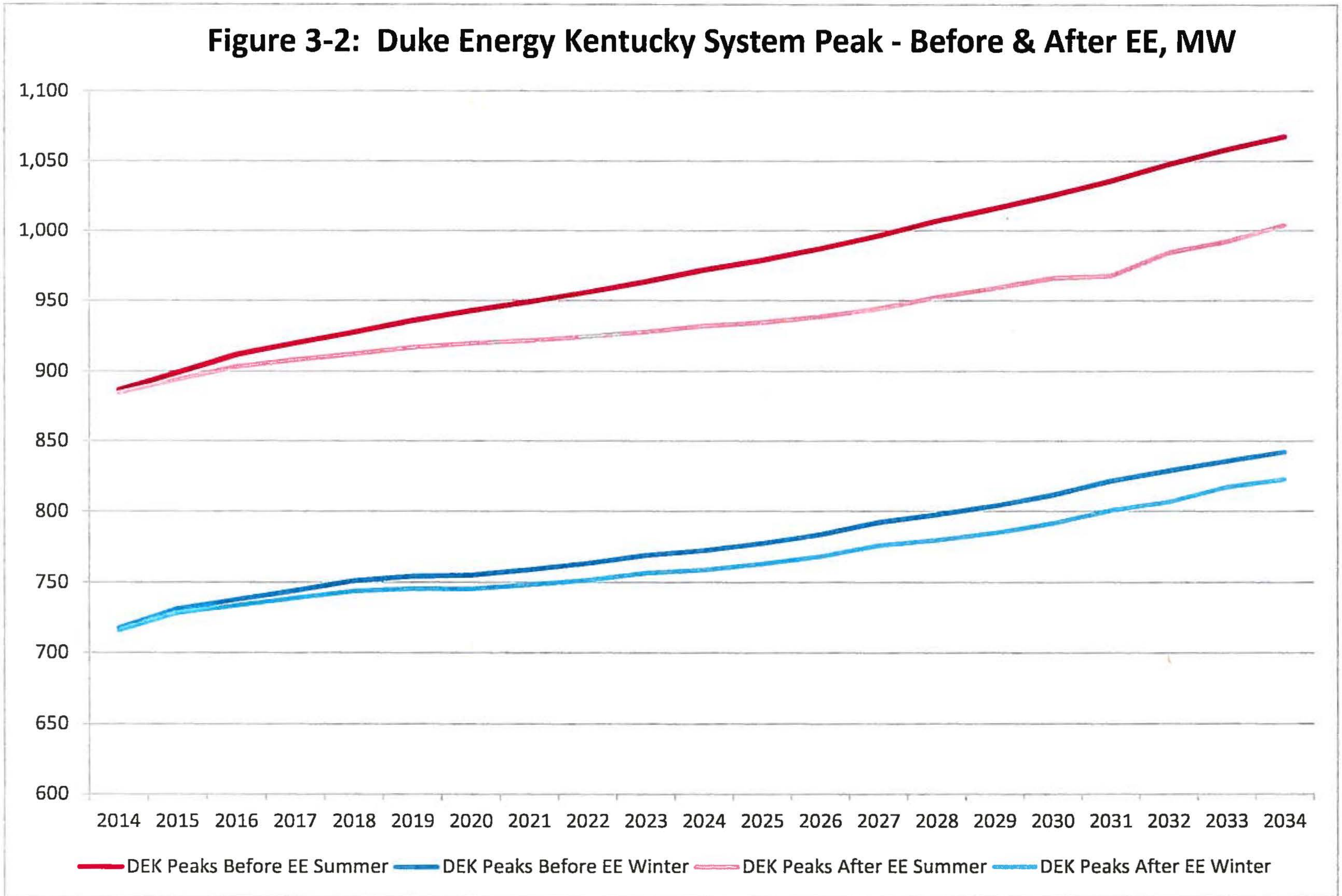


Figure 3-2: Duke Energy Kentucky System Peak - Before & After EE, MW
1,100
1,050
1,000
950
900
850
800
750
700
650
600
2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034
DEK Peaks Before EE Summer
DEK Peaks Before EE Winter
DEK Peaks After EE Summer
DEK Peaks After EE Winter

**Actual vs. Forecast**

Table 3-C compares the actual and forecast energy and peak demands (after DR program impacts) to the forecast developed in the Spring of 2008.

**TABLE 3-C**

**ELECTRIC ENERGY AND PEAK LOAD**

**COMPARISON: ACTUAL VS. FORECAST**

| | Energy - MWH | | Internal Peak - MW | |
|---|---|---|---|---|
| Year | Actual | Forecast | Actual | Forecast |
| 2009 | 4,016,170 | 4,262,536 | 808 | 948 |
| 2010 | 4,246,725 | 4,298,510 | 899 | 956 |
| 2011 | 4,197,454 | 4,345,291 | 886 | 899 |
| 2012 | 4,182,359 | 4,337,805 | 871 | 900 |
| 2013 | 4,312,505 | 4,330,328 | 871 | 903 |

All numbers are after EE.
(Actual energy data is from Table B-2, actual peak data is from Table B-4, in App B.)

**Changes In Methodology**

In 2013, the Company incorporated Itron's Statistically Adjusted End-Use (SAE) modeling process for the development of its energy and peak forecasts. The Company also uses the latest historical data available and relies on recent economic data and forecasts from Moody's.

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

Consistent with the Commission's IRP analytical requirements and the Commission's Order in Case No. 2008-408, Duke Energy Kentucky continuously evaluates and considers opportunities for DSM to meet its resource needs, and specifically as part of this IRP.[1] Duke Energy Kentucky's DSM programs include traditional conservation EE programs and 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 described in greater detail in Appendix C:

- Residential Smart $aver®
- Residential Energy Assessments Program
- Energy Efficiency Education Program for Schools Program
- Low Income Services Program
- Residential Direct Load Control - Power Manager Program
- Smart $aver® Prescriptive Program
- Smart $aver® Custom Program
- Peak Load Manager (Rider PLM) - PowerShare® Program
- Appliance Recycling Program
- Low Income Neighborhood Program
- My Home Energy Report Program

### B. DSM PROGRAMS AND THE IRP

The projected impacts of DSM programs have been included in this IRP. The conservation DSM programs are projected to reduce energy consumption by approximately 378,000 MWh and 55 MW by 2029. The Residential Direct Load Control Program (Power Manager) is projected to reduce peak demand by 12 MW and the PowerShare® program another 26 MW by 2029. This brings the total peak reduction across all programs to approximately 93 MW by 2029. Table 4-A summarizes the projected load impacts included in this IRP analysis.

[1] *In the Matter of the Consideration of the New Federal Standards of the Energy Independence and Security Act,* Case No. 2008-00408, Order at p. 18 (July 24, 2013).

**Table 4-A**

**Projected DSM Impacts**

| | | | DR Impacts - MW | | | Total DSM Impacts - MW |
|---|---|---|---|---|---|---|
| Year | EE Impacts - MWh | EE Impacts - MW | Power Share | Power Manager | Total | Total |
| 2014 | 20,291 | 2.4 | 21.3 | 11.2 | 32.5 | 34.9 |
| 2015 | 41,924 | 6.3 | 14.7 | 11.9 | 26.6 | 32.9 |
| 2016 | 64,858 | 10.6 | 16.9 | 12.1 | 29.0 | 39.6 |
| 2017 | 88,176 | 15.0 | 20.8 | 12.2 | 33.0 | 48.0 |
| 2018 | 112,340 | 19.6 | 23.5 | 12.2 | 35.7 | 55.3 |
| 2019 | 136,503 | 23.7 | 26.3 | 12.2 | 38.5 | 62.2 |
| 2020 | 160,667 | 28.2 | 26.3 | 12.3 | 38.6 | 66.8 |
| 2021 | 184,830 | 32.9 | 26.3 | 12.3 | 38.6 | 71.5 |
| 2022 | 208,994 | 37.5 | 26.3 | 12.3 | 38.6 | 76.1 |
| 2023 | 233,157 | 42.1 | 26.3 | 12.3 | 38.6 | 80.7 |
| 2024 | 257,321 | 46.6 | 26.3 | 12.3 | 38.6 | 85.2 |
| 2025 | 281,485 | 51.4 | 26.3 | 12.3 | 38.6 | 90.0 |
| 2026 | 305,648 | 44.2 | 26.3 | 12.3 | 38.6 | 82.8 |
| 2027 | 329,812 | 47.8 | 26.3 | 12.3 | 38.6 | 86.4 |
| 2028 | 353,975 | 51.3 | 26.3 | 12.3 | 38.6 | 89.9 |
| 2029 | 378,139 | 55.0 | 26.3 | 12.3 | 38.6 | 93.6 |
| 2030 | 402,303 | 58.6 | 26.3 | 12.3 | 38.6 | 97.2 |
| 2031 | 426,466 | 62.2 | 26.3 | 12.3 | 38.6 | 100.8 |
| 2032 | 450,630 | 65.7 | 26.3 | 12.3 | 38.6 | 104.3 |
| 2033 | 474,793 | 69.5 | 26.3 | 12.3 | 38.6 | 108.1 |

Note: the EE MW impacts are coincident to the Summer Peak.

# 5. SUPPLY-SIDE RESOURCES

A wide variety of supply-side resource options were considered in the screening process. These generally included 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 considered to meet customers' energy needs. These options include continuing service or repowering of existing generating units; 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 system needs by considering their technical feasibility, fuel availability and price, length of contract or life of resource, construction or implementation lead time, capital and operations and maintenance (O&M) cost, reliability, and environmental effects.

## B. EXISTING UNITS

### 1. Description

The total installed net summer generation capability owned by Duke Energy Kentucky is 1,069 MW. This capacity consists of 577 MW of coal-fired steam capacity and 492 MW of natural gas-fired peaking capacity, as described in Table A-3.

The steam capacity consists of two coal-fired units located at the East Bend Unit 2 Generating Station (East Bend) and Miami Fort 6, located at the Miami Fort station. The peaking capacity consists of six natural gas-fired CTs located at the Woodsdale station. These units have propane as a back-up fuel. East Bend is jointly owned with The 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). 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 essential for reliable, low cost service. The following list 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.

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

In addition to the regularly scheduled maintenance outages, a program of "availability outages" is conducted. These are unplanned, opportunistic, proactive short-duration outages for enhancing 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. Generating station performance is measured by station equivalent availability, equivalent forced outage rate, and a comparison of the station cost to the market price of electricity. Plant-by-plant assessments of the causes of all forced outages 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.

## 4. Fuel Supply

### Coal

Coal is procured by the Company's Regulated Fuels Group (Regulated Fuels) to provide a reliable supply in quantities sufficient to meet generating requirements at the lowest reasonable cost. The "cost" of the coal is the evaluated cost, which includes the purchase price of the coal "free on board" at the shipping point, transportation to the station, the cost of emissions based on the sulfur content, and the effects of coal quality on station equipment operations.

Regulated Fuels uses set broad fuel procurement policies such as hedging guidelines and inventory levels that aid in contract negotiations. These policies are combined with economic and market forecasts and probabilistic dispatch models to aid in the procurement strategy for fuel purchasing. The strategy provides a guide for maintaining a reliable supply of low cost fuel.

To provide coal supply reliability, Regulated Fuels utilizes a mix of term contract and spot market purchases from a variety of proven suppliers in a dispersed geographic area and maintains coal stockpiles at each station to account for possible short-term supply disruptions. Disruptions that could affect coal supply are evaluated according to their potential duration and probability. Sufficient coal is kept on hand to maintain adequate supply these potential disruptions.

The coal supply currently comes primarily from the states of Ohio, Kentucky, West Virginia, Pennsylvania, and Illinois. These states are projected to have decades of remaining economically recoverable reserves.

Long-term coal supply agreements provide approximately 70% to 80% of annual coal requirements. 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 long-term commitment. Dedicated, proven reserves assure coal supply of the specified quantity and quality. Specified pricing, delivery schedules, and contract length provide suppliers with the financial stability for capital investment and labor requirements and provide protection from market price fluctuations. This is accomplished using a combination of low fixed-escalation, market price re-openers, and contract extension options. The remainder of the coal need is filled with spot purchases to:

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

**Natural Gas**

Natural gas for electric generating purposes has been limited to peaking applications. 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. This Agreement allows Duke Energy Kentucky to purchase gas supply from a 3rd party if Sequent does not provide an agreeable price.

**Propane**

Propane is used at Woodsdale as back-up fuel in case natural gas is unavailable and as a hedge against high natural gas prices. Woodsdale maintains about 10,000 barrels of onsite propane storage at the station. A Propane Services Agreement with Enterprise TE Products Pipeline Company LLC (Enterprise) provides Duke Energy Kentucky with additional use of 48,000 barrels of offsite storage space at the Todhunter caverns, and the ability to purchase propane at market prices. Per this agreement, Woodsdale can pull propane stored offsite via pipeline from inventory owned by Duke Energy Kentucky, and/or use up to 40,000 barrels from Enterprise on loan for replacement within 45 days. However, Enterprise declared *force majeure* in December 2013 and claims it is unable to perform its contract obligations. Duke Energy Kentucky management and legal teams are currently reviewing this situation. Natural gas was never unavailable to Woodsdale during the unusually cold winter of 2013/14, so the lack of Enterprise services did not cause fuel-related unit outages.

**Oil**

East Bend and Miami Fort 6 use 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.

**Fuels Research**

Regulated Fuels monitors potential changes in the fuel industry such as mining methodologies and the availability of different fuels. The focus of Duke Energy Kentucky's fuel-related research and development efforts is to develop leading-edge technologies and provide information, assessments, and decision-making tools to support fuel cost reduction and environmental risk management.

### 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 NYMEX and fuel contracts and price quotes from fuel providers in response to regular Duke Energy fuel supply requests for proposals. The Duke Energy long-term fundamental forecast is a proprietary product developed for Duke Energy by EVA, a leading energy consulting firm. The assumptions used in the development of the Duke Energy fundamental forecast were developed by both EVA and Duke Energy in-house subject matter experts. The Duke Energy long-term fundamental forecast is approved annually by Duke Energy Leadership 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, 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 time. Routine maintenance projects that may maintain or increase the efficiency of generating stations are planned within the context of such requirements. Any changes in plant capacity, operating and maintenance cost, or efficiency due to environmental controls are accounted for in the IRP process.

**8. Age of Units**

Miami Fort 6 is 54 years old and East Bend is 33 years old. As previously mentioned, Miami Fort 6 is slated for possible retirement as early as May 31, 2015. The primary driver for the possible near term retirement date is the lack of advanced $SO_2$ and NOx controls needed to comply with the recently updated MATS Rule that becomes effective for purposes of compliance in mid-April 2015. However, the multiple emerging environmental regulations (including new water quality standards, fish impingement and entrainment standards, Coal Combustion Residuals (CCR) rule and the new $SO_2$, Particulate Matter (PM) and Ozone NAAQS together drive the likely retirement of Miami Fort 6.

Generating unit age alone is not the sole identifier for the likelihood of equipment failure. 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, operated, and maintained, all impact 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 long-term performance 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 resulting loss of unit availability. Examples of such practices 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 destructive examinations such as taking boiler tube samples or high-energy piping "boat" samples. These monitoring methods 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. 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).

Finally, few technological breakthroughs have occurred relating to coal-fired steam units since the early-1950s, before which 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, the emergence of other generating technologies were not enough to force technological obsolescence of coal generation.

## 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 and/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 MW 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

On January 1, 2012, Duke Energy Kentucky generation and transmission assets were transferred from the Midcontinent Independent System Operator (MISO) to PJM. As a condition of joining PJM, Duke Energy Kentucky signed the PJM Reliability Assurance Agreement (RAA). Rather than participate fully in the PJM Capacity market, and under Commission directive, Duke Energy Kentucky satisfies its capacity obligation for the RAA under the Fixed Resource Requirement (FRR) alternative. As an FRR entity, Duke Energy Kentucky owns or contracts for specific generation to meet its yearly PJM defined capacity obligation, and submits an FRR Capacity Plan annually to demonstrate compliance. In addition, Duke Energy Kentucky engages in short term energy and capacity transactions within the PJM market for the benefit of its customers, as well as investigates the long term purchase/sale of capacity as an alternative to the construction/operation of additional generation facilities.

Duke Energy's three Midwest utility operating companies[2] (collectively Duke Energy Midwest) are 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.

## E. NON-UTILITY GENERATION AS FUTURE RESOURCE OPTIONS

It is Duke Energy Kentucky's practice to cooperate with potential cogenerators and independent power producers. However, a major concern 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 has two cogeneration tariffs available to customers but does not currently have any contracts for cogeneration. In practice, Duke Energy Kentucky supplies any customer interested in cogeneration with a copy of these tariffs and discusses 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. 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 MW levels of this activity. Cogeneration facilities built to affect customer energy and demand served

[2] Duke Energy's three Midwest utility operating companies are Duke Energy Kentucky, Duke Energy Ohio, and Duke Energy Indiana, Inc.

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, 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 carbon capture sequestration, Integrated Gasification Combined Cycle (IGCC) with carbon capture sequestration, CTs, CC units, and nuclear units. In addition, renewable technologies such as wind, municipal waste landfill gas, and solar were considered in this year's screening analysis.

Technology types were screened within their own general category of baseload/intermediate, peaking, and renewable, the goal of which is to pass the best alternatives from each category to the integration process. The initial screening analysis determines 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 expansion model (described in detail in Chapter 8).

### 1. Process Description

#### Information Sources

The cost and performance data for each technology are based primarily on the Burns & McDonnell (B&M) Generic New Unit study. B&M is an architecture and engineering (A&E) active in the electric utility industry. The B&M study was benchmarked against research and information from internal subject matter experts, the Electric Power Research Institute (EPRI) Technology Assessment Guide (TAG®), and studies performed by and/or information gathered from external sources. In addition, fuel and operating cost estimates are developed internally by Company personnel, and/or from other sources such as those mentioned above. The B&M 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, efforts are made to ensure 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 consistent across a variety of technology types in today's construction material, manufactured equipment, and commodity markets, remains challenging.

#### 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 energy storage technologies*** (Lead acid, Lithium-ion, Sodium Ion, Zinc Bromide, Flywheels, pumped storage, etc.) remain relatively expensive compared to conventional generation sources, but the benefits to a utility such as the ability to shift load and firm renewable generation are obvious. Research, development, and demonstration continue within Duke Energy. Duke Energy Generation Services has installed a 36 MW advanced acid lead battery at the Notrees wind farm in Texas that began commercial operation in December 2012. In Indiana, Duke Energy has installed a 75 kilowatt (kW) battery which is integrated with solar generation and electric vehicle charging stations. Duke Energy also has other storage system tests within its Envision Energy demonstration in Charlotte, which includes two Community Energy Storage (CES) systems of 24 kW and three substation demonstrations each less than 1 MW.
- ***Compressed Air Energy Storage*** (CAES), although demonstrated on a utility scale and generally commercially available, is not a widely applied technology and remains relatively expensive. The high capital requirements for these resources arise from the fact that suitable sites that possess the proper geological formations and conditions necessary for the compressed air storage reservoir are relatively scarce.
- ***Small modular nuclear reactors*** (SMR) are generally defined as having capabilities of less than 300 MW. While the U.S. Department of Energy (DOE) solicited bids in 2012 for companies to participate in a small modular reactor grant program with the intent to "promote the accelerated commercialization of SMR technologies to help meet the nation's economic energy security and climate change objectives," SMRs are still conceptual in design and are developmental in nature. Currently, there is no industry experience with developing this technology outside of the conceptual phase. Duke Energy will be monitoring the progress of the SMR project for potential consideration and evaluation for future resource planning. Even if technically feasible, the state moratorium on nuclear power prevents the use of SMRs.
- ***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 ranges from a few kW to tens of MW 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 and swine waste digesters*** remain relatively expensive and face operational and/or permitting challenges. Research, development, and demonstration continue, but these technologies remain generally too expensive or face obstacles that make them impractical energy choices outside of specific mandates calling for their use. Such projects are typically small and so would not materially impact the IRP.
- ***Woody Biomass*** was not included new construction of such units is relatively expensive compared to other traditional and renewable generating sources. Economics for woody biomass typically become more favorable for boiler conversion and co-firing where fuel is readily available. Comparing conversion costs would not be consistent with the new construction costs modeled for the other generating technologies. This technology is limited by fuel availability and access to delivery by truck, so the unit must be in close proximity to its fuel sources. This limits site availability for this generating technology. Due to these unique criteria, biomass generation options are evaluated on a case by case basis.

The interest in clean air emissions has led to a deeper investigation of renewable technologies. Landfill gas, solar photovoltaic, and wind technologies were added to the screening analyses for this IRP.

**Economic Screening**

The prices for coal, gas, and emission allowance used in the supply-side screening analysis, were the same as those utilized in the System Optimizer analysis (discussed in Chapter 8). The technologies were screened using relative dollar per kW-year versus capacity factor. The screening within each general class used a confidential spreadsheet-based model developed 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 installed cost of the technology, *i.e.*, the Y-intercept on the graph (see Appendix A for individual graphs). Then the variable costs, such as fuel, variable O&M, and emission allowance prices associated with operating the technology 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. 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 are not 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[3]. The technologies were screened both with and without a projected cost of $CO_2$ emissions.

[3] 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.

**Baseload/Intermediate Technologies**

Figures A-1a (No $CO_2$) and A-1b (with $CO_2$) in Appendix A show the screening curves for baseload/intermediate generation. Natural gas CC with duct firing and inlet chilling is the least-cost technology compared to nuclear, super-critical pulverized coal (SCPC) with carbon capture and storage (CCS), and IGCC with CCS in both cases. The capital and operating costs of carbon capture technology are still the subjects of ongoing industry studies and research, along with the feasibility and costs of geological storage of $CO_2$ once it is captured. The baseload/intermediate technologies are:

1) 723 MW SCPC with CCS to 1100 lbs. $CO_2$/MWh
2) 525 MW IGCC with CCS to 1100 lbs. $CO_2$/MWh
3) 2 x 1,117 MW Nuclear
4) 688 MW 2x2x1 F-frame, Fired and Chilled CC
5) 866 MW 2x2x1 Advanced Class, Fired and Chilled CC
6) 1302 MW 3x3x1 Advanced Class, Fired and Chilled CC

**Peak Technologies**

Figures A-2a (No $CO_2$) and A-2b (with $CO_2$) in Appendix A show the screening curves for peak generation. The simple-cycle, heavy frame CT unit makes up the lower envelope of the curves across the entire capacity factor in the with $CO_2$ and no $CO_2$ cases. Both of these technologies are modeled with evaporative coolers and dual fuel capabilities. The peak technologies are:

1) 4 x 44 MW Simple-Cycle, Fast Start CTs
2) 4 x 200 MW Simple-Cycle, Heavy Frame CTs

**Renewable Technologies**

Figure A-3 in Appendix A shows the screening curves for renewable category generation. Busbar chart comparisons involving wind and solar resources can be somewhat misleading because they do not contribute their full installed capacity at the time of the system peak[4]. Since busbar charts attempt to levelize and compare costs on

[4] For purposes of this IRP, wind resources are assumed to contribute 13% of installed capacity at the time of peak and solar resources are assumed to contribute 38% of installed capacity at the time of peak.

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, $CO_2$ cost does not impact their operating cost. Solar appears to be the least cost renewable alternative through its maximum practical capacity factor range followed closely by wind. Landfill gas is the most costly renewable within the renewable category but provides a larger capacity factor range versus the wind and solar options. The renewable technologies are:

1) 150 MW Wind
2) 25 MW Solar Photovoltaic
3) 5 MW Landfill Gas Internal Combustion Engine

### 3. Unit Size

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

Project scope and estimated costs used for conventional technology types such as CTs and CCs were developed by B&M. EPRI TAG®, equipment vendors, and Duke Energy's experience were used for comparability. 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 each technology. 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 CTs is about three years, about four years for CCs, and approximately six and a half years for coal units. However, the time required to obtain regulatory approvals and environmental permits adds uncertainty, so judgment is used also.

### 6. R&D Efforts and Technology Advances

New energy and technology alternatives are needed to ensure a long-term sustainable electric future. Duke Energy's research and development (R&D) activities enable tracking of new options such as modular, 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 R&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's membership in EPRI provides an additional source of emerging R&D information.

### 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 environmental 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 ITS REPLACEMENT – CROSS STATE AIR POLLUTION RULE (CSAPR)

The EPA finalized its Clean Air Interstate Rule (CAIR) in May 2005. The CAIR limits total annual and ozone season $NO_X$ 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 and directing the Agency to continue administering the rule until a viable replacement rule was in place.

In August 2010, EPA proposed a replacement rule for CAIR, known as the Cross State Air Pollution Rule (CSAPR). The CSAPR was finalized in 2011. In the CSAPR, EPA established state-level annual $SO_2$ caps and annual and ozone season $NO_X$ caps that were to take effect in 2012. Further restrictions on $SO_2$ emissions for Phase II implementation were to take effect in 2014. In response to legal challenges to the rule, the CSAPR was vacated by the D.C. Circuit in 2012. Again, the court directed the EPA to continue administering the CAIR until a viable replacement rule for the CSAPR was in place. In 2013 the Supreme Court granted EPA's petition to review the D.C. Circuit decision. Oral arguments were held in December 2013. On April 29, 2014, the Supreme Court issued its decision overturning the D.C. Circuit Court's vacatur, and remanded the rule back to the Court for further proceedings. Duke Energy Kentucky cannot predict the outcome of those proceedings at this time. The CAIR Phase II annual and ozone season programs are set to take effect on January 1, 2015.

## B. MATS 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. The rule was vacated by the D.C Circuit in February 2008.

EPA published the MATS rule in May 2011 as the replacement for CAMR and finalized it in December 2011. The MATS rule regulates hazardous air pollutant emissions from new and existing coal or oil fired steam EGUs greater than 25 MWs in size. The compliance date is April 16, 2015. A source may request up to a one year extension of the compliance date from its state environmental regulator.

This rule is the primary reason for the potential retirement of Miami Fort 6, since the capital requirements for compliance are not economic.

## C. 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. In September 2011 the Obama Administration announced that EPA would not finalize the proposal ahead of the Agency's normal 5-year review cycle for the ozone standard. The EPA is expected to propose a revised ozone standard by the end of 2014, and finalize it in the fall of 2015. The EPA is again considering a standard in the 60 to 70 ppb range. Based on this schedule, compliance for any areas designated as nonattainment could come in the 2020 – 2023 timeframe depending on the severity of a nonattainment area's classification. Meanwhile, the EPA has moved ahead with implementation of the 75 ppb standard that it finalized in 2008. The EPA finalized area designations in April 2012. Parts of three counties in the Cincinnati area were designated as marginal nonattainment areas.

### 2. $SO_2$ Standard

On June 22, 2010 EPA finalized a 75 ppb 1-hour $SO_2$ NAAQS and revoked the annual and 24-hour $SO_2$ standards. On July 25, 2013 EPA made a limited number of final nonattainment designations. The EPA designated parts of two counties in Kentucky as nonattainment. Neither designation is expected to impact Duke Energy Kentucky operations.

The EPA issued a proposed rule in the spring of 2014 that describes requirements for state air agencies to characterize $SO_2$ concentrations through ambient monitoring or air quality modeling techniques in targeted areas around the country in which the largest sources of $SO_2$ emissions are located. The air quality information collected by air agencies will then be used to inform designations for areas not designated nonattainment in July 2013. The rule will reference appropriate guidance on monitoring and modeling techniques, and it will include timelines for air agencies to conduct the required analyses. The EPA has proposed that final area designations be made by December 2017 for areas in which states use modeling to characterize air quality, and by December 2020 for areas in which states use monitoring to characterize air quality.

## D. REGULATION OF GHG EMISSIONS

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 GHG emissions for determining when a source is potentially subject to Prevention of Significant Deterioration (PSD) permitting for GHGs. The Tailoring Rule took effect on January 2, 2011. Being subject to PSD permitting requirements for GHG emissions will require a Best Available Control Technology (BACT) analysis and the application of BACT for GHGs. Also, all potential modifications will be evaluated for compliance with NSR, including the potential for 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 January 8, 2014, the second version (EPA withdrew its first proposal) of EPA's proposed New Source Performance Standards (NSPS) for $CO_2$ emissions for new pulverized coal (PC), integrated gasification combined cycle (IGCC), and stationary natural gas-fired CTs and CCs was published in the federal register. The EPA proposed a limit of 1,100 lb $CO_2$/gross MWh for new PC and IGCC units, and 1,000 or 1,100 lb $CO_2$/gross MWh for stationary combustion turbines depending on unit size. EPA could finalize the rule in early 2015. Regardless of the final rule requirements, it will not impact any existing Duke Energy Kentucky electric generating facility.

The EPA proposed GHG emission guidelines for existing electric generating units on June 2, 2014, and is expected to finalize the guidelines by June 1, 2015. The EPA also issued a separate proposal that would establish CO2 emission limits that would only apply to an existing generating unit that undergoes a modification or is reconstructed. Once EPA finalizes emission guidelines, the states will be required to develop the regulations that will apply to covered sources, based on the emission performance standards established by EPA in its guidelines. It is still very early in this rulemaking process, so it is not known at this time how either of these proposals might impact Duke Energy Kentucky electric generating facilities. The final rules could be significantly different from the proposals.

Duke Energy Kentucky does not expect the U.S. Congress to pass federal climate change legislation limiting $CO_2$ emissions or otherwise setting a price on $CO_2$ emissions through a mechanism such as a tax or a cap-and-trade program in 2014.

## E. WATER QUALITY

### 1. <u>Clean Water Act Sections 316(a) and 316(b)</u>

Protection of single fish species and aquatic communities is a primary focus of water permitting for coal, oil, gas, and nuclear power plants and industrial facilities under the Clean Water Act Section 316(a) - heated cooling water discharges, and 316(b) – entrainment through cooling water intake systems and impingement on intake screens. East Bend 2 has minimal exposure to this requirement since it uses a closed loop cooling tower system, and Miami Fort 6 is likely to be retired before the rules are effective.

EPA signed the final rule implementing §316(b) of the Clean Water Act (CWA) on May 19, 2014. The rule is expected to be published in the Federal Register in June 2014 and effective 60-days afterwards. The rule establishes aquatic protection requirements for existing facilities and new on-site generation that are defined as existing facilities with a design intake flow of 2 million gallons per day (mgd) or more from waters of the U.S., utilize at least 25% of the water withdrawn for cooling purposes, and is defined as a point source under the CWA. The rule establishes mortality reduction requirements due to both fish impingement and entrainment and advances a two-phased approach for compliance. Under the first phase, Best Technology Available (BTA) for entrainment will need to be determined through a site-specific evaluation The installation of cooling towers was not specified as presumptive BTA. However, closed-cycle cooling and fine mesh screens must be evaluated as BTA for entrainment mortality reduction. Duke Energy has not observed significant impacts to the aquatic communities due to the operation of the cooling water intakes at the Kentucky stations. It is, therefore, unlikely that cooling towers would be warranted at Miami Fort 6. The environmental impacts from the operation of the cooling water intakes will be further evaluated, and the need for the installation of entrainment protective technologies, such as cooling towers, will be assessed over a 3 to 5 year time period as allowed under the rule. Under the second phase, the facility is allowed to select between one of seven compliance alternatives to demonstrate compliance with the impingement standard.

## 2. <u>Steam Electric Effluent Limitation Guidelines</u>

In September 2009, EPA announced plans to revise the steam electric effluent limitation guidelines. The steam electric effluent limitation guidelines are based on the capability of the best technology available. On April 19, 2013, the EPA Acting Administrator signed the proposed revisions to the Steam Electric Effluent Limitations Guidelines (ELGs). The proposal was published in the Federal Register on June 7, 2013, with comments due to EPA by the extended date of September 20, 2013. Duke Energy filed its comments on the proposed rule on September 19, 2013. Under the current revision of the consent decree, the EPA has agreed to issue a final rule by September 30, 2015. The EPA has proposed eight different regulatory options within the rule, of which four are listed as preferred by EPA. The eight regulatory options vary in stringency and cost, and propose revisions or development of new standards for seven waste streams, including wastewater from air pollution control equipment and ash transport water. The proposed revisions are focused primarily on coal generating units, but some revisions would be applicable to all steam electric generating units, including natural gas and nuclear-fueled generating facilities. After the final rulemaking, effluent limitation guideline requirements will be included in a station's National Pollutant Discharge Elimination System (NPDES) permit renewals. Portions of the rule would be implemented immediately after the effective date of the rule upon the renewal of wastewater discharge permits, while other portions of the rule will be implemented upon the renewal of the wastewater discharge permits after July 2017. EPA expects that all facilities will be in compliance with the rule by July 2022. These dates may be extended due to the extension of time for EPA to complete the rulemaking. The deadline to comply will depend upon each station's permit renewal schedule.

**3. <u>CCRs</u>**

In April 2000, EPA issued a regulatory determination for fossil fuel combustion wastes (65 FR 32214, May 22, 2000). The purpose of the determination was to decide whether certain wastes from the combustion of fossil fuels should remain exempt from subtitle C (management as hazardous waste) under the Resource Conservation and Recovery Act (RCRA). The Agency's decision was to retain the exemption from hazardous waste management for all of the fossil fuel combustion wastes. However, the Agency also determined and announced that waste management regulations under RCRA subtitle D (management as non-hazardous wastes) are appropriate for certain coal combustion wastes that are disposed in landfills and surface impoundments.

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 develope a rule to manage CCRs. CCRs include fly ash, bottom ash and FGD byproducts (including 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.

In June 2010, EPA issued its proposed rule regarding CCRs. The proposed rule offers two options: 1) a hazardous waste classification under RCRA Subtitle C and 2) a non-hazardous waste classification under RCRA Subtitle D, along with dam safety and alternative rules. Both options would include strict new requirements regarding the handling, disposal and potential re-use ability of CCRs. The proposal could result in more conversions to dry handling of ash, more landfills, closures of existing ash ponds and the addition of new wastewater treatment systems. Final regulations are not expected to be issued by EPA until December 2014 or later. EPA's regulatory classification of CCRs as hazardous or non-hazardous will be critical in developing plans for handling CCRs. The impact to Duke Energy Kentucky is unknown at this time. Based on a late 2014 final rule date, compliance with new regulations is generally expected to begin around 2020.

## F. EMISSION ALLOWANCE MANAGEMENT

CAIR is currently in effect. Under CAIR, $SO_2$ allowances utilize the 1990 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 2014 and forward CAIR $SO_2$ and $NO_x$ compliance; however there could be a need to purchase, or opportunity to sell, allowances based on variable unit operation.

East Bend Unit 2 has an SCR for $NO_x$ control and an FGD for $SO_2$ control and is generally positioned well for compliance. Miami Fort 6 does not have advanced $SO_2$ or $NO_x$ controls installed and will be challenged to meet compliance. Options to meet compliance may include purchasing $SO_2$ and $NO_x$ emission allowances from within the state of Ohio, switching to a lower sulfur coal, or limiting operation of the unit or some combination of these options.

The $NO_x$ and $SO_2$ allowance prices were obtained from near-term market indications from brokers and escalated for the out years. The $CO_2$ prices are per Duke Energy's carbon planning case. The emission prices 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** | **May 19, 2014** | Mid-2018 | 316(b) - regulates cooling water intake requirements |
| **Effluent Guidelines** | **June 7, 2013** | September 30, 2015 | 2018-2023 | |
| **Air** | | | | |
| **Cross State Air Pollution Rule** | **August 2, 2010** | **August 8, 2011** | Stayed and Litigated | Supreme Court overturned vacatur |
| **Mercury and Air Toxics Standards Rule** | **May 3, 2011** | **February 16, 2012** | April 16, 2015 | |
| **Waste** | | | | |
| **Coal Combustion Residuals Rule** | **June 21, 2010** | December 19, 2014 | 2019-2020 | |
| **Climate** | | | | |
| **Greenhouse Gas Regulation – New Source Performance Standards for Existing Units** | **June 2, 2014** | June 2015 | 2020 | Tailoring Rule in effect **Jan. 2, 2011** for PSD and Title V |

## Table 6-B - Estimated Environmental Impact Summary (2015-2020)

| | | **Miami Fort Unit 6** | **East Bend** |
|---|---|---|---|
| **Issue** | **Likely Impact Date** | **Potential Impacts to Duke Energy Kentucky Coal Units** | |
| MATS Rule | 2015 | Hg, PM, HCl Monitoring<br>ACI, DSI, Low Sulfur Coal for HAPs Control | Hg, PM, Monitoring |
| NAAQS $SO_2$ Std. | 2022-2025 | Low Sulfur Coal For $SO_2$ Reduction; Risk For $SO_2$ Scrubber Or Baghouse With DSI | |
| NAAQS Ozone Std. | 2020-2023 | Selective Non-Catalytic Reduction | SCR Upgrade Risk |
| 316(b) | 2018+ | Intake Screen Upgrades | Intake Screen Upgrades |
| Effluent Guidelines | 2018+ | Dry Fly Ash Handling Conversion; Waste Water Treatment Upgrade | Waste Water Treatment Upgrade |
| CCR Rule | 2019+ | Ash Pond Closure, New Waste Water Treatment, Dry Ash Handling Conversion, New Lined Landfill Risks | Ash Pond Closure, New Waste Water 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 describes the integration process, sensitivity analyses, selection of the 2014 IRP, and its general implementation.

At the end of this chapter, Figure 8-1 shows Duke Energy Kentucky's Load, Capacity, and Reserves table for 2014-2034. Figure 8-2 shows the Capacity and Energy mix in 2015.

## B. RESOURCE INTEGRATION PROCESS

The goal of the integration process was to take all of the pre-screened DSM, supply-side, and environmental compliance options and develop an IRP using a consistent method of evaluation. The tools used 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 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 (PAR) is a detailed production-cost model for simulation of the optimal operation an electric utility's generation facilities. Key inputs include generating unit, fuel, load, transaction, DSM, emission and allowance cost, and system operating data.

### *Engineering Screening Model*

Historically, Duke Energy Kentucky's in-house Engineering Environmental Compliance Planning and Screening Model (ESM) has been used to reduce a large number of air-emission control alternatives to the most economic options. Because East Bend is already well controlled, and since capital-intensive FGD or baghouse controls are not economic for Miami Fort 6, there are few remaining control options. As a result, no specific screening activity was performed. However, the model's functionality was useful to organize modeling information and provide modeling data for emission control alternatives to the System Optimizer and PAR models.

The ESM incorporates generating unit operating characteristics (net MW, heat rates, emission rates, emission control equipment removal rates, availabilities, variable operating and maintenance expenses, etc.) and market information (energy, emission allowance, and 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 free cash flow with the inclusion of capital costs.

The ESM also contains costs and operating characteristics of emission control equipment. For Miami Fort 6, primary possible alternatives include dry sorbent injection for hydrogen chloride (HCl) reduction; selective non-catalytic reduction (SNCR) for NOx removal; activated carbon injection (ACI) for mercury removal; and various fuel switching options with related capital costs (such as a switch to lower sulfur content coal with required fuel handling safety upgrades). The model also appropriately treats emission reduction co-benefits, such as increased mercury removal with the combination of controls such as SCR and FGD. The model is considered proprietary confidential and competitive information by Duke Energy Kentucky.

## 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, and nuclear units were limited to blocks of 35 MW, even though actual units utilizing these technologies are normally much larger. Using comparably sized units creates a level playing field so that choices will be made based on economics rather than unit size. 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, the capital costs on a $/kW basis would be much higher than the cost estimates used in this analysis. Duke Energy Kentucky can 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 for such a facility.

The number of renewable technology types was limited to allow the model to reach a solution more easily. Based on the results of the screening curve analysis, Biomass, Wind and Solar renewables were modeled since these were the most prevalent types of renewables.

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

**Table 8-A Technologies Considered**

| Technology | Cost Basis (MW) | Modeled (MW) | % Peak Contribution |
|---|---|---|---|
| Nuclear | 1,117 (2 units) | 35 | 100% |
| SCPC w/CCS 1,110 lb/MWh | 723 | 35 | 100% |
| Composite Coal | 195 | 195 | 100% |
| CT | 199 (4 units) | 35 | 100% |
| CC | 619 Unfired<br>68 Duct fired | 32 Unfired<br>3 fired | 100% |
| Wind | 150 | 12.5 | 13% |
| Solar | 25 | 8 | 42% |
| Biomass Landfill Gas | 5 | 2 | 100% |

Nuclear units were considered as resource alternatives even though Kentucky currently has a moratorium on nuclear power plants until a long-term federal disposal site becomes operational. This was done to provide insights into what kinds of resources may be needed in the future, especially given the potential for future constraints on carbon emissions. Also, a 195 MW Composite Coal unit was modeled based on the cost and operating characteristics of favorable coal-based proposals received in a recent request for proposal (RFP) for capacity.

DSM programs were modeled as load and energy reductions from the load forecast. DSM costs and impacts were assumed to continue throughout the planning period.

Any generic CTs and CCs selected by the model can be viewed as placeholders for peaking and baseload/intermediate duty market purchases. Similarly, any generic pulverized coal, 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-seven year period (2014-2040). The final detailed production costing modeling in PAR was performed over a twenty-one year period.

### 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 and in a range of risk sensitivity 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 resources configurations required to meet an annual 13.7% planning reserve margin while minimizing the long-run revenue requirements to customers, with differing operating (production) and capital costs. Nominal 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
- Projected load and generation resource need
- A menu of new generation resource options with corresponding costs and timing parameters
- An assumed level of NOx, $SO_2$ based on the CSAPR
- Assumed costs for $CO_2$ emissions

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 on the impacts of different carbon policies in the longer term.

The information shown on the following pages outlines the planning options considered in the portfolio analysis phase. Each portfolio contains DR, EE, and the estimated REPS impact. Currently there is no Kentucky or federal REPS. However, to assess the impact to the long-term resource need, it is prudent to plan for one. This IRP assumes that 5% of retail sales would be met with renewable energy sources beginning in 2019, increasing 0.5% annually through 2028.

## 4. Develop Scenarios and Portfolios

Two scenarios were chosen to illustrate the impacts of key risks and decisions.

**SCENARIOS**

1. $CO_2$ Regulation (Reference Case): $CO_2$ price curve beginning in 2020 represents the potential for future federal climate change legislation. The cost of emitting 1 ton of $CO_2$ is assumed to be $17/ton in 2020, increasing to $53/ton in 2034. Given the timing of this IRP and the recently proposed rule for GHGs, this case serves as a proxy for the proposed rule. Once the proposed rule is better understood, its impacts will be more specifically modeled.
2. No $CO_2$ regulation (No $CO_2$ Case): $CO_2$ emissions have no cost in this scenario. The total cost can be compared to the Reference Case as an approximation of the cost of carbon regulation.

**PORTFOLIOS**

Portfolio options were tested under the nominal set of inputs as well as a variety of risk scenarios and sensitivities, in order to understand the strengths and weaknesses of various resource configurations and evaluate the long-term costs to customers under various potential outcomes. The five portfolios analyzed are shown below and in Table 8-B:

- **Portfolio 1**: Miami Fort 6 retires in 2015 and is replaced with the composite coal unit
- **Portfolio 2**: Miami Fort 6 retires in 2020 and is replaced with the composite coal unit in 2015
- **Portfolio 3:** Miami Fort 6 retires in 2020 and is replaced with CC in 2020
- **Portfolio 4**: Miami Fort 6 retires and replaced with composite coal in 2015; All coal retires in 2027 and replaced with CC capacity in 2027
- **Portfolio 5:** Miami Fort 6 retires and replaced with composite coal in 2015; All coal retires in 2027 and replaced with CT capacity in 2027

## Table 8-B – Portfolios Evaluated

<table>
<tr><th>Year</th><th>Portfolio 1</th><th>Portfolio 2</th><th>Portfolio 3</th><th>Portfolio 4</th><th>Portfolio 5</th><th>Renewables (Same in all Portfolios)</th></tr>
<tr><td>2015</td><td>MF6 Retires 195 MW Coal</td><td>195 MW Coal</td><td></td><td>MF6 Retires 195 MW Coal</td><td>MF6 Retires 195 MW Coal</td><td rowspan="6">7 MW Solar<br>4 MW Wind</td></tr>
<tr><td>2016</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>2017</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>2018</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>2019</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>2020</td><td></td><td>MF6 Retires</td><td>MF6 Retires 170 MW CC</td><td></td><td></td></tr>
<tr><td>2021</td><td></td><td></td><td></td><td></td><td></td><td rowspan="5">20 MW Solar<br>6 MW Wind</td></tr>
<tr><td>2022</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>2023</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>2024</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>2025</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>2026</td><td></td><td></td><td></td><td></td><td></td><td rowspan="5">7 MW Solar<br>6 MW Wind</td></tr>
<tr><td>2027</td><td></td><td></td><td></td><td>East Bend 2 Retires 195 MW Coal Retires 490 MW CC</td><td>East Bend 2 Retires 195 MW Coal Retires 70 MW CC 455 MW CT</td></tr>
<tr><td>2028</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>2029</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>2030</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>2031</td><td></td><td></td><td></td><td></td><td></td><td rowspan="4">3 MW Solar</td></tr>
<tr><td>2032</td><td></td><td></td><td></td><td>35 MW CC</td><td>35 MW CC</td></tr>
<tr><td>2033</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>2034</td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

**SENSITIVITIES**

The sensitivities representing the highest future risks were evaluated in both scenarios:

- Coal prices
  - Higher Coal Prices (15% higher)
  - Lower Coal Prices (15% lower)
- Gas prices
  - Higher Gas Prices (15% higher)
  - Lower Gas Prices (15% lower)
- Capital Costs
  - Higher cost for traditional, wind, & solar generation
  - Lower cost for traditional, wind, & solar generation
- Renewables - A No-REPS sensitivity was performed to determine how much renewable energy would be selected as a least cost resource. This serves as a benchmark that allows for estimating the cost of an RPS.
- Purchases and Sales – The base assumption was to allow purchases and sales to develop the base portfolios. Since Duke Energy Kentucky is part of PJM, the opportunity to make economic sales and purchases provides value since it enables energy purchases from the PJM market when prices are low and energy sales when prices are high. The following model runs were also conducted as a way to quantify the benefit of participating in the energy markets and to show the source of that benefit:
  - No purchases or sales
  - Purchases only
  - Sales only

### 5. Quantitative Analysis Results

#### a. Evaluation of Retirement Decision at Miami Fort 6

This analysis evaluated the cost effectiveness of controls on Miami Fort 6 to meet anticipated environmental regulatory requirements versus retirement and replacement with CC generation. Per the System Optimizer evaluation, the optimal replacement for Miami Fort 6 was 195 MW of composite coal generation in 2015 in all scenarios.

Three portfolios were used to evaluate the cost effectiveness of installation of controls versus retirement of the unit and replacement and detailed in Table 8-C:

- **Portfolio 1:** Miami Fort 6 retires in 2015, replaced with the composite coal unit
- **Portfolio 2:** Miami Fort 6 retires in 2020, replaced with the composite coal unit in 2015
- **Portfolio 3:** Miami Fort 6 retires in 2020, replaced with CC in 2020

Each combination of scenario and portfolio was evaluated with 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 on a 21 and 10 year basis.

**Table 8-C PVRR Comparisons**

**21 Year Perspective**

| **Reference Case** | **Portfolio 1** | **Portfolio 2** | **Portfolio 3** |
|---|---|---|---|
| 21 Year PVRR (MM$) | 3,813 | 3,856 | 3,952 |
| Delta (MM$) | | 43 | 139 |

| **No CO2 Case** | **Portfolio 1** | **Portfolio 2** | **Portfolio 3** |
|---|---|---|---|
| 21 Year PVRR (MM$) | 2,896 | 2,940 | 3,174 |
| Delta (MM$) | | 44 | 277 |

**10 Year Perspective**

| **Reference Case** | **Portfolio 1** | **Portfolio 2** | **Portfolio 3** |
|---|---|---|---|
| 10 Year PVRR (MM$) | 1,799 | 1,841 | 1,877 |
| Delta (MM$) | | 43 | 79 |

| **No CO2 Case** | **Portfolio 1** | **Portfolio 2** | **Portfolio 3** |
|---|---|---|---|
| 10 Year PVRR (MM$) | 1,574 | 1,618 | 1,681 |
| Delta (MM$) | | 44 | 107 |

Portfolio 1 was the lowest cost option to customers versus installation of controls over a 21 year and 10 year time period in both scenarios. There is also a significant risk that additional environmental controls could be required at Miami Fort 6 as future regulatory requirements emerge. Based on the economics of retirement versus controlling Miami Fort 6 as well as the future risks, retiring the unit in 2015 and replacing it with the composite coal unit is the most cost effective option.

**b. Detailed Portfolio Analysis**

The focus of the detailed portfolio analysis was to determine the optimum resource selection assuming Miami Fort 6 is retired in 2015, and to identify the type and timing of future generation in the longer term under both scenarios. The potential resource planning strategies were tested under the Reference Case which includes a carbon cost and the No-Carbon case as well as variations in fuel and energy cost, capital costs and the presence of a REPS.

For both scenarios 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 21-year analysis time frame was used to fully capture the long-term impact of the technology selected to replace Miami Fort 6 if retired in 2015. Additionally, a 10 year perspective was also considered, when relevant, to add insight to the timing of value provided by the various assets. Table 8-D below shows the PVRR's for each portfolio in both scenarios.

In this analysis, the least cost portfolio in the Miami Fort 6 retirement analysis (Portfolio 1) was compared to two other plausible portfolios. Portfolio 2 was eliminated based on economics and risk profile. Specifically, those four portfolios are:

- **Portfolio 1:** Miami Fort 6 retires in 2015 and is replaced with the composite coal unit
- **Portfolio 3:** Miami Fort 6 retires in 2020 and is replaced with CC in 2020
- **Portfolio 4**: Miami Fort 6 retires and replaced with composite coal in 2015; All coal retires in 2027 & replaced with CC capacity in 2027

- **Portfolio 5:** Miami Fort 6 retires and replaced with composite coal in 2015; All coal retires in 2027 & replaced with CT capacity in 2027

In both scenarios on both a 21-year and 10-year basis, Portfolio 1 is most cost effective.

**Table 8-D**
**Comparison of Portfolios**
**(Cost in MM$)**

**21 Year Perspective**

| | Portfolio 1 | Portfolio 3 | Portfolio 4 | Portfolio 5 |
|---|---|---|---|---|
| **Reference Case** | 3,813 | 3,952 | 3,832 | NA |
| **No CO2 Case** | 2,896 | 3,174 | NA | 3,222 |

**10 Year Perspective**

| | Portfolio 1 | Portfolio 3 | Portfolio 4 | Portfolio 5 |
|---|---|---|---|---|
| **Reference Case** | 1,799 | 1,877 | 1,805 | NA |
| **No CO2 Case** | 1,574 | 1,681 | NA | 1,581 |

Scenario analysis is the first step in determining the preferred portfolio. Now that the portfolios have been evaluated in different internally consistent futures, the analysis moves to a framework where different risk factors, as measured by sensitivities, and portfolio attributes, are measured. While not currently expected, but possible, if some event triggers the retirement of coal resources in the 2027 time frame, it appears at this time that the addition of combined cycle generation would be the least cost option. This possibility will be evaluated in future IRP's.

## IMPACTS & COMMENTARY ON
## VARIOUS SENSITIVITIES & PORTFOLIO ATTRIBUTES

### c. Fuel Price Sensitivities

Sensitivities for coal and gas were performed independently to measure the responsiveness of the portfolios to changes in fuel prices. This was done in both scenarios and for the most plausible portfolios:

- **Portfolio 1:** Miami Fort 6 retires in 2015 and is replaced with the composite coal unit
- **Portfolio 3:** Miami Fort 6 retires in 2020 and is replaced with CC in 2020
- **Portfolio 4**: Miami Fort 6 retires and replaced with composite coal in 2015; All coal retires in 2027 & replaced with CC capacity in 2027
- **Portfolio 5:** Miami Fort 6 retires and replaced with composite coal in 2015; All coal retires in 2027 & replaced with CT capacity in 2027

**Table 8-E: HIGH COAL PRICE SENSITIVITY**

| | Portfolio 1 | Portfolio 3 | Portfolio 4 | Portfolio 5 |
|---|---|---|---|---|
| **Reference Case** | 4,018 | 4,123 | 3,994 | NA |
| **No $CO_2$ Case** | 3,100 | 3,349 | NA | 3,396 |

It is important to view sensitivities in the context of the scenario analysis. In the scenario analysis, Portfolio 1 was shown to be the most cost effective portfolio in both scenarios. The High Coal sensitivity adds perspective to that analysis and shows that in a future with carbon regulation and high coal prices, combined cycle generation would be a cost-effective replacement for the coal resources. In the No-$CO_2$ case, the composite coal unit is still preferred to gas generation. This serves as a sign post for future analysis to be mindful of the effects carbon and high coal prices have on the portfolio in the latter part of the 2020's.

**Table 8-F: LOW COAL PRICE SENSITIVITY**

| | Portfolio 1 | Portfolio 3 | Portfolio 4 | Portfolio 5 |
|---|---|---|---|---|
| **Reference Case** | 3,607 | 3,774 | 3,663 | NA |
| **No $CO_2$ Case** | 2,692 | 2,987 | NA | 3,048 |

The Low Coal sensitivity provides additional insights in that despite the additional cost born by coal generation as a result of a price on carbon, the benefit of lower coal prices maintain Portfolios 1's cost advantage. An important factor that comes out of the evolving GHG rule will be the impact that it has on the fuel markets. It is reasonable to believe that carbon regulation will exert downward pressure on coal prices, and this fuel price - carbon cost relationship will be important to monitor in future analysis.

**Table 8-G: HIGH GAS PRICE SENSITIVITY**

| | Portfolio 1 | Portfolio 3 | Portfolio 4 | Portfolio 5 |
|---|---|---|---|---|
| Reference Case | 3,818 | 4,021 | 3,913 | NA |
| No $CO_2$ Case | 2,910 | 3,243 | NA | 3,324 |

The High Gas sensitivity produces results that one would expect and as in the scenario analysis, Portfolio 1 is not affected as much by the higher gas prices and remains the most cost effective portfolio in both scenarios.

**Table 8-H: LOW GAS PRICE SENSITIVITY**

| | Portfolio 1 | Portfolio 3 | Portfolio 4 | Portfolio 5 |
|---|---|---|---|---|
| Reference Case | 3,802 | 3,861 | 3,729 | NA |
| No $CO_2$ Case | 2,883 | 3,091 | NA | 3,120 |

The Low Gas sensitivity shows the responsiveness of Portfolios 4 and 5 to changes in gas prices. In the Reference Case, lower gas prices provide a distinct advantage to gas generation in a carbon regulated future. But without the presence of a cost on carbon, the lower gas prices and less carbon intensive gas generation does not overcome the cost advantage of Portfolio 1.

This will be another key relationship to analyze with the evolving GHG rule. Despite the uncertainty around the final rule and how the commonwealth of Kentucky will implement it, it is reasonable to believe that the low coal price sensitivity and high gas price sensitivity are more likely; in both of these sensitivities Portfolio1is the most cost effective.

**d. Capital Cost Sensitivity**

Numerous capital cost sensitivities were modeled for a number of portfolios and varied the cost of traditional gas fired generation, solar and wind resources across both scenarios. A number of observations can be made based on the results:

- In general, renewable resources were not economic. This is a function of the relatively low capital costs of the composite coal resource vs. renewable energy resources as well as the lack of need for additional resources.
- As one would expect, the lower capital cost sensitivity for solar and wind resources results in additional generation with the majority of that being solar.

**e. Impact of REPS**

As previously mentioned, a primary assumption is the presence of a future REPS that would require the purchase of a minimum amount of renewable energy. The REPS adds approximately 1.5% to the cost of the preferred portfolio in the Reference Scenario. In the No $CO_2$ Regulation Scenario, the REPS adds approximately 3.2% to the cost of the preferred portfolio.

**f. Discussion of Market Purchases and Sales**

Participation in PJM affords the opportunity to purchase energy from the market during times when the market price is less than the cost of generation. Additionally, during times when the market price is higher than the cost of generation, excess energy can be sold into the market.

In both scenarios, these economic purchase and sales reduce the expected PVRR's by 10%-15%. Further investigation of this aspect of the portfolio shows that economic purchases account for approximately 80% of this savings.

**g. Short Term Implementation Plan**

Based on the economics of the scenario and sensitivity analysis, Duke Energy Kentucky will continue to pursue a coal acquisition as part of the current RFP process to replace the Miami Fort 6 capacity. Going forward, monitoring the evolution of the recently proposed GHG Rule will be an important activity. This will be a multi-year effort as the rule gets finalized on a federal level, state implementation plans need to be developed and approved, as well as the resolution of any legal challenges. The issue will be analyzed and included in future IRP's.

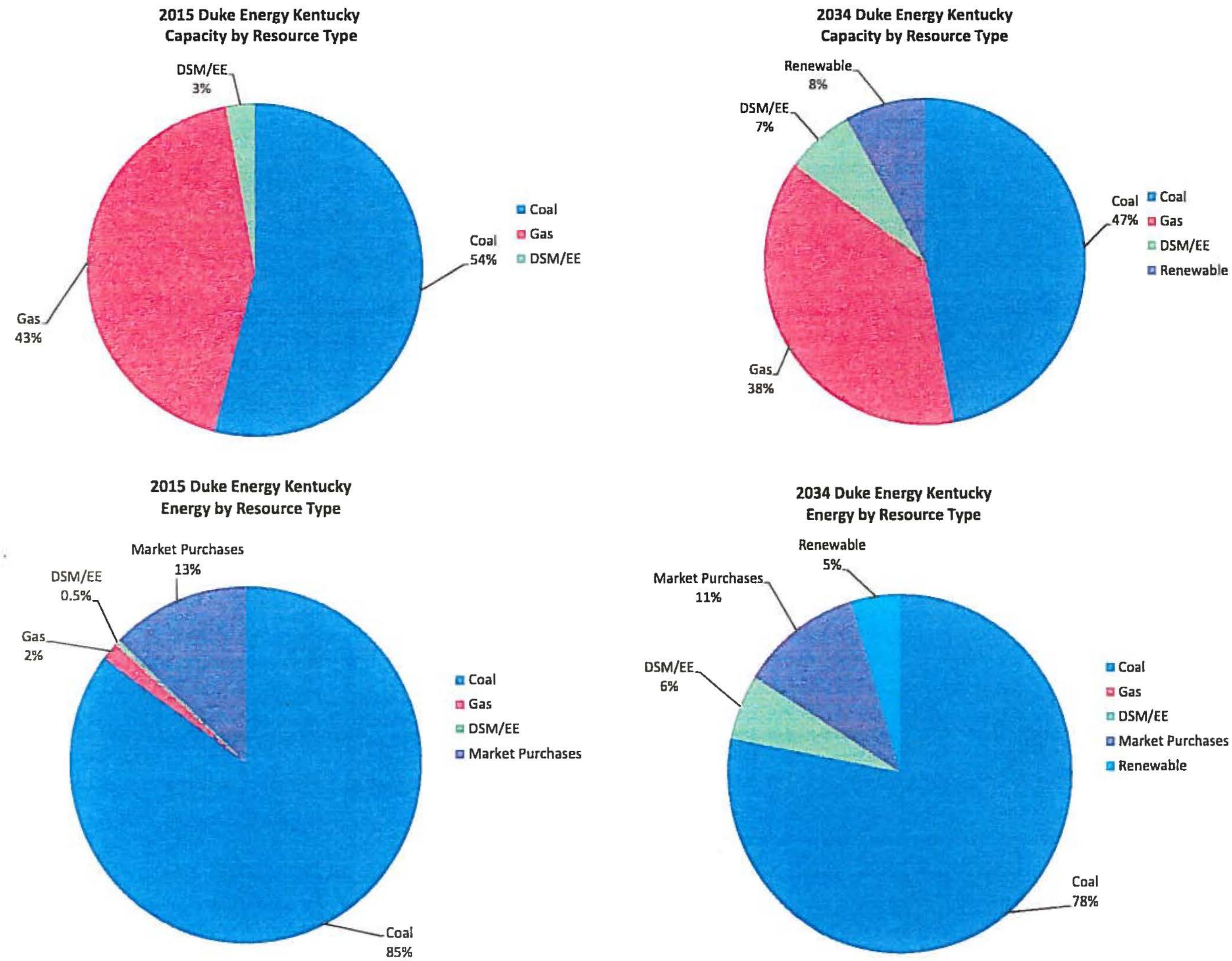
# Figure 8-1 Load, Capacity and Reserves Table

**Summer Projections of Load, Capacity, and Reserves**
**for Duke Energy Kentucky 2014 IRP**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast | | | | | | | | | | | | | | | | | | | | | |
| 1 Duke System Peak | 886 | 900 | 913 | 920 | 927 | 934 | 931 | 935 | 939 | 944 | 949 | 954 | 960 | 968 | 968 | 976 | 985 | 999 | 1,004 | 1,014 | 1,024 |
| Reductions to Load Forecast | | | | | | | | | | | | | | | | | | | | | |
| 2 New EE Programs | (2) | (5) | (8) | (11) | (14) | (17) | (21) | (24) | (27) | (31) | (34) | (38) | (41) | (44) | (38) | (40) | (43) | (58) | (48) | (51) | (51) |
| 3 Demand-Side Management | | | | | | | | | | | | | | | | | | | | | |
| Power Share | (21) | (15) | (17) | (21) | (24) | (26) | (26) | (26) | (26) | (26) | (26) | (26) | (26) | (26) | (26) | (26) | (26) | (26) | (26) | (26) | (26) |
| Power Manager | (11) | (12) | (12) | (12) | (12) | (12) | (12) | (12) | (12) | (12) | (12) | (12) | (12) | (12) | (12) | (12) | (12) | (12) | (12) | (12) | (12) |
| **4 Adjusted Duke System Peak** | **852** | **869** | **876** | **876** | **877** | **878** | **872** | **872** | **873** | **874** | **877** | **878** | **881** | **885** | **892** | **897** | **903** | **903** | **918** | **924** | **934** |
| Cumulative System Capacity | | | | | | | | | | | | | | | | | | | | | |
| 4 Generating Capacity | 1,067 | 1,067 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 |
| 5 Capacity Additions | 0 | 0 | 0 | 0 | 0 | 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 | (163) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 Cumulative Generating Capacity | 1,067 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 | 904 |
| 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 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 |
| Peaking/Intermediate | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewables | 0 | 0 | 0 | 0 | 0 | 5 | 11 | 16 | 21 | 28 | 32 | 37 | 39 | 44 | 50 | 50 | 50 | 50 | 50 | 50 | 53 |
| **13 Cumulative Production Capacity** | **1,067** | **1,099** | **1,099** | **1,099** | **1,099** | **1,104** | **1,109** | **1,115** | **1,120** | **1,127** | **1,130** | **1,135** | **1,137** | **1,143** | **1,148** | **1,148** | **1,148** | **1,148** | **1,148** | **1,148** | **1,152** |
| Reserves | | | | | | | | | | | | | | | | | | | | | |
| 14 Generating Reserves | 215 | 229 | 223 | 222 | 222 | 226 | 237 | 243 | 247 | 253 | 254 | 258 | 257 | 258 | 256 | 251 | 245 | 245 | 231 | 224 | 217 |
| **15 % Reserve Margin** | **25.3%** | **26.4%** | **25.4%** | **25.4%** | **25.3%** | **25.7%** | **27.2%** | **27.8%** | **28.3%** | **28.9%** | **28.9%** | **29.4%** | **29.2%** | **29.2%** | **28.7%** | **28.0%** | **27.1%** | **27.2%** | **25.1%** | **24.3%** | **23.3%** |
| 16 % Capacity Margin | 20.2% | 20.9% | 20.3% | 20.2% | 20.2% | 20.5% | 21.4% | 21.8% | 22.1% | 22.4% | 22.4% | 22.7% | 22.6% | 22.6% | 22.3% | 21.9% | 21.3% | 21.4% | 20.1% | 19.5% | 18.9% |

The figures below represent the changes in the capacity mix and energy mix between 2015 and 2034. The relative shares of renewables, energy efficiency, and gas all increase, while that of coal decreases.

**Figure 8-2 Generation Mix 2015 and 2034**



*Kentucky*

# The Duke Energy Kentucky 2014 Integrated Resource Plan

## July 1, 2014

## 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.

The data sources include the B&M Study and EPRI TAG®, which is licensed, trade secret material that is proprietary and confidential to B&M and EPRI, respectively. Duke Energy Kentucky and its consultants consider cost estimates provided by consultants to be confidential and competitive information. Duke Energy Kentucky also considers its internal cost estimates to be confidential and competitive information. The redacted information will be made available to appropriate parties upon execution of appropriate confidentiality agreements or protective orders

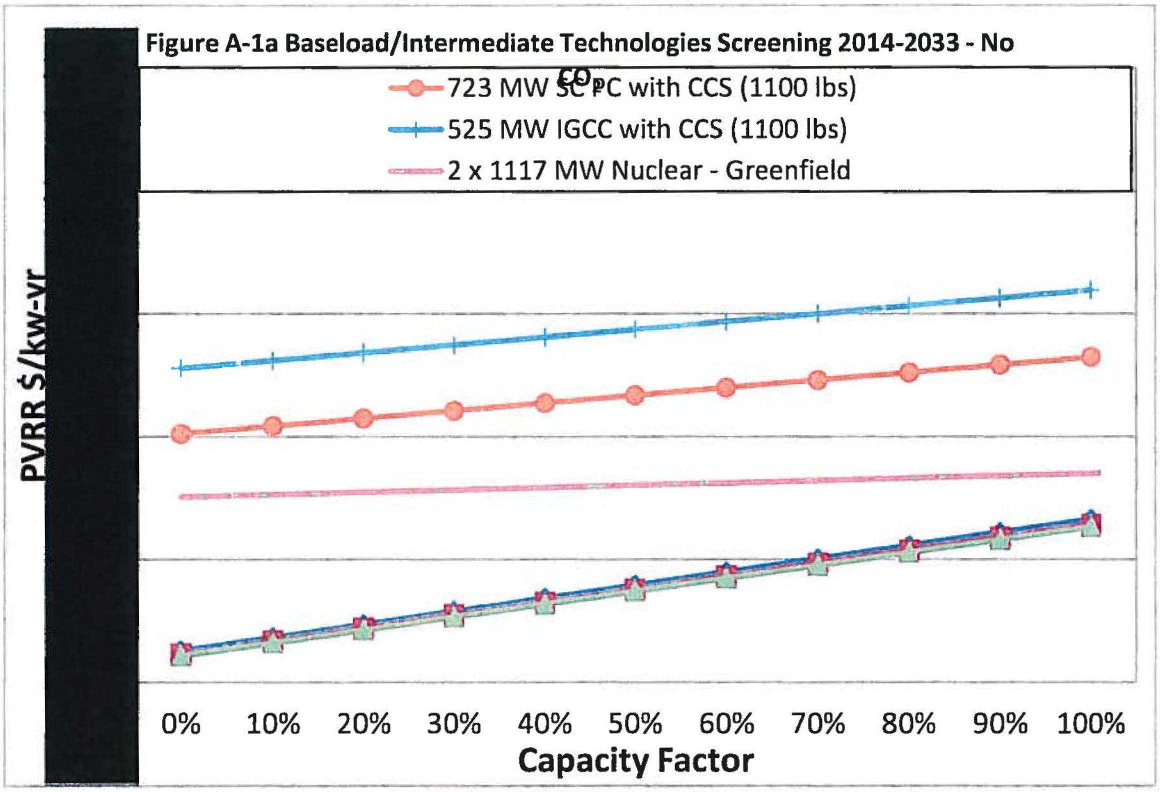
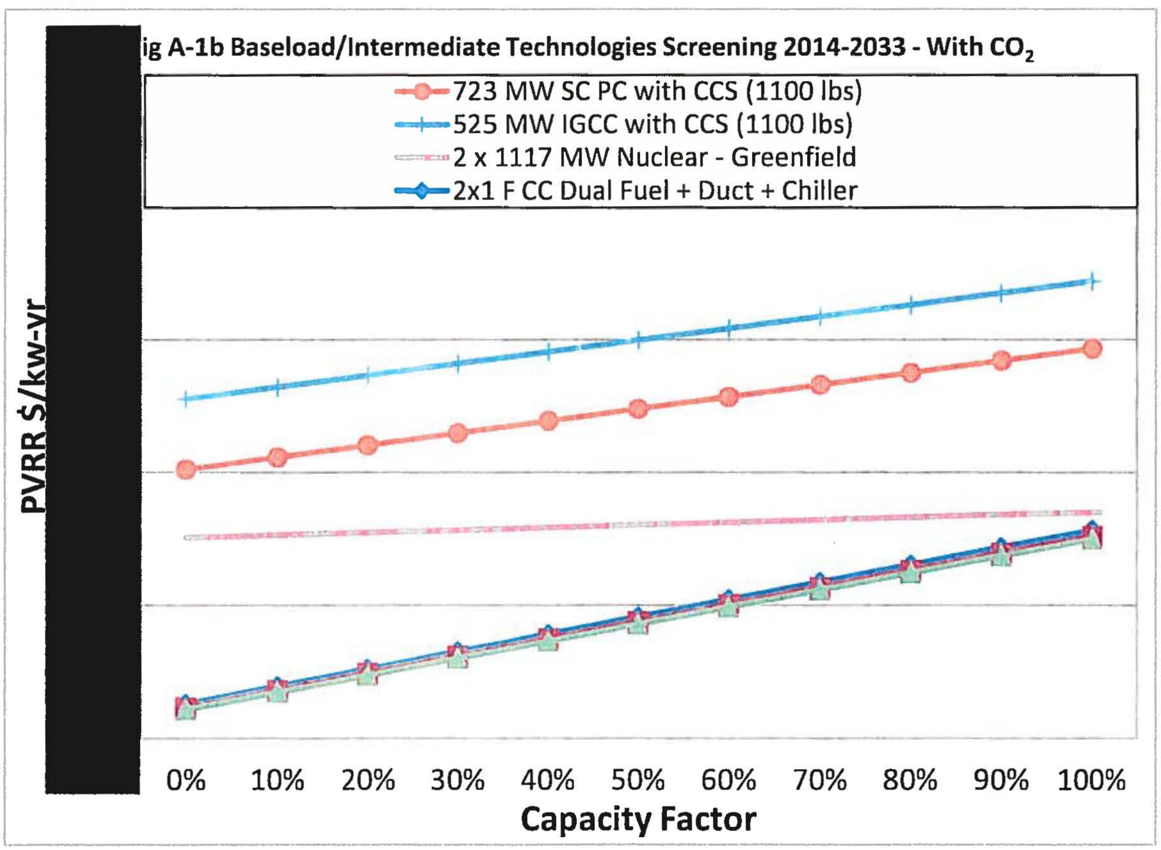


Figure A-1a Baseload/Intermediate Technologies Screening 2014-2033 - No CO₂
723 MW SC PC with CCS (1100 lbs)
525 MW IGCC with CCS (1100 lbs)
2 x 1117 MW Nuclear - Greenfield
[redacted]
PVRR $/kw-yr
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Capacity Factor


ig A-1b Baseload/Intermediate Technologies Screening 2014-2033 - With CO₂
723 MW SC PC with CCS (1100 lbs)
525 MW IGCC with CCS (1100 lbs)
2 x 1117 MW Nuclear - Greenfield
2x1 F CC Dual Fuel + Duct + Chiller
[redacted]
PVRR $/kw-yr
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Capacity Factor

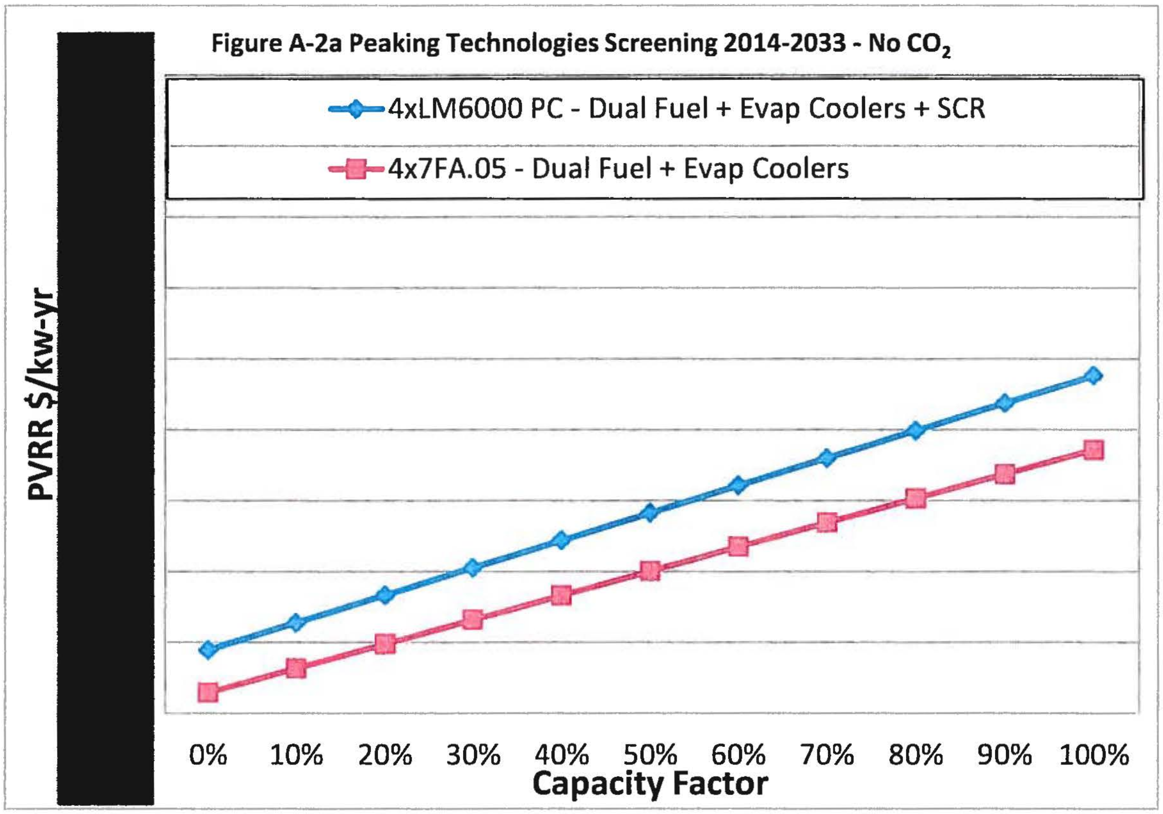



**Figure A-2a Peaking Technologies Screening 2014-2033 - No $CO_2$**

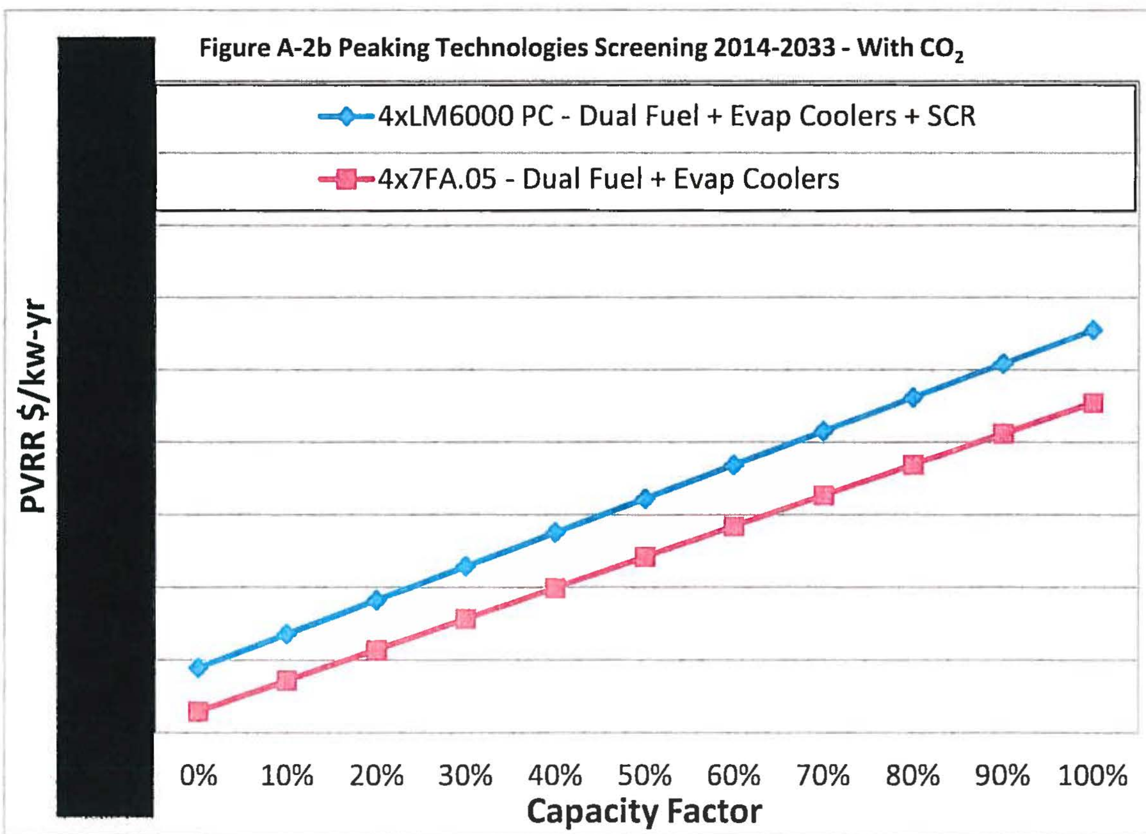
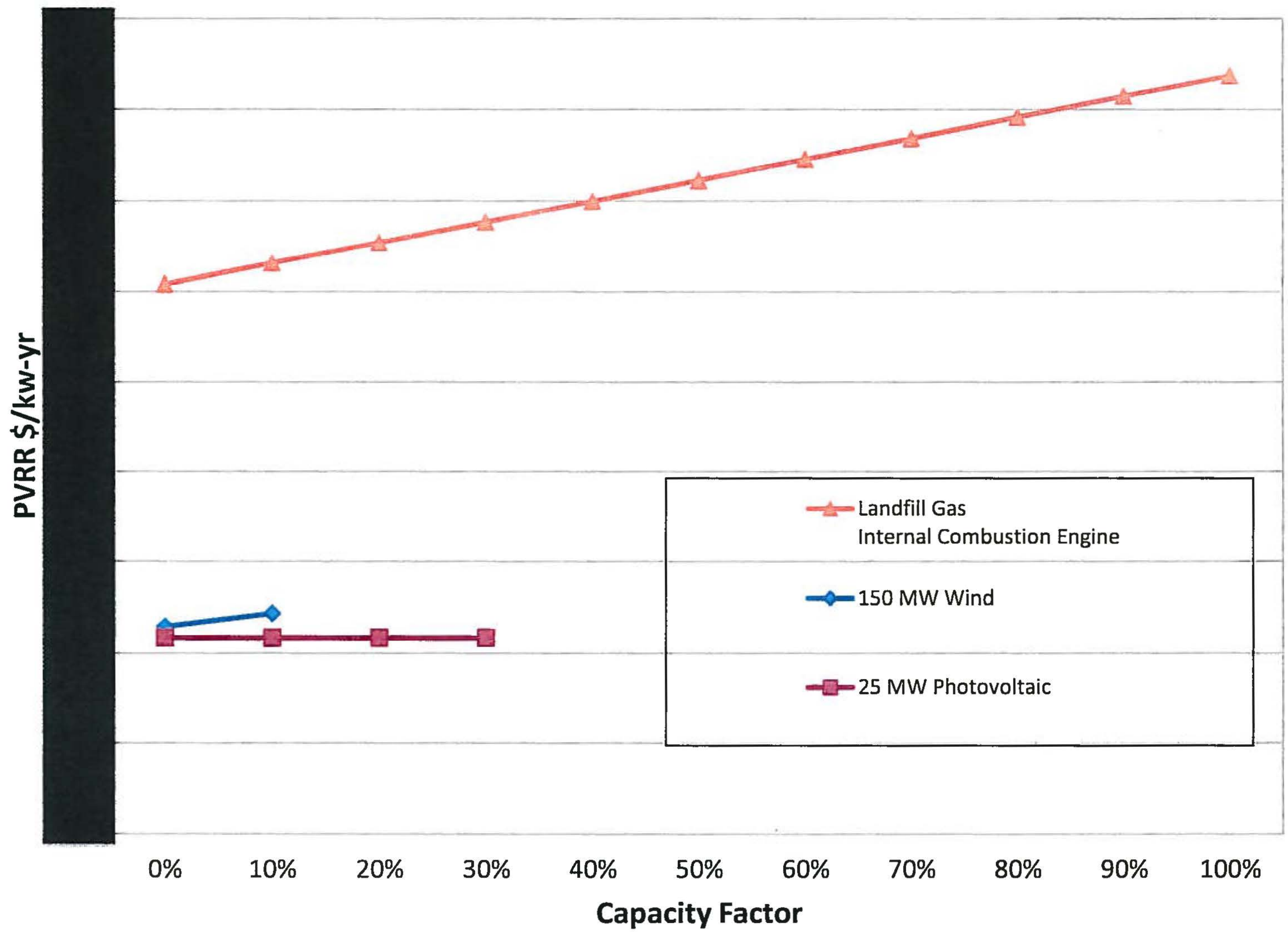



**Figure A-2b Peaking Technologies Screening 2014-2033 - With $CO_2$**

**Figure A-3 Renewable Technologies 2014 - 2033**



## Table A-1 Supply Side Technology Information 2014-2033

| | |
|---|---|
| Discount Rate | 6.21% |
| Coal Price Escalation Rate | 2.50% |
| Gas Price Escalation Rate | 2.50% |
| EA Price Escalation Rate | 2.50% |
| FOM and VOM Escalation Rate (%) | 2.50% |

Confidential business information

| | | Plant A | Plant B | Plant C | Plant D | Plant E | Plant F | Plant G | Plant H | Plant I | Plant J | Plant K |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Technology Description | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Book Life/Tax Life | Years | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Nominal Unit Size at 100% Load | MW | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Total Plant Cost for Screening (2014 completion date) | $/kW | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Total Plant Cost for Screening (incl AFUDC-2014 completion date) | $/kW | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Total Plant Cost for Screening (incl AFUDC-2014 completion date) | MM$ | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Average Annual Heat Rate | Btu/kWh | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| VOM in 2014$ | $/MWh | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| FOM in 2014$ | $/kW-yr | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Equivalent Planned Outage Rate | % | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Equivalent Unplanned Outage Rate | % | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Equivalent Availability | % | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| SO2 Emission Rate | Lbm/MMbtu | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| NOx Emission Rate | Lbm/MMBtu | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Hg Emission Rate | Lbm/Tbtu | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| CO2 Emission Rate | Lbm/MMBtu | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [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

| Annual Allowance Price Forecast (Nominal $/Ton) | | | | |
|---|---|---|---|---|
| | $SO_2$ | NOx | | $CO_2$ |
| | | Annual | Ozone | |
| 2014 | [redacted] | | | $ - |
| 2015 | | | | $ - |
| 2016 | | | | $ - |
| 2017 | | | | $ - |
| 2018 | | | | $ - |
| 2019 | | | | $ - |
| 2020 | | | | $ 17 |
| 2021 | | | | $ 19 |
| 2022 | | | | $ 21 |
| 2023 | | | | $ 22 |
| 2024 | | | | $ 24 |
| 2025 | | | | $ 26 |
| 2026 | | | | $ 28 |
| 2027 | | | | $ 31 |
| 2028 | | | | $ 33 |
| 2029 | | | | $ 36 |
| 2030 | | | | $ 39 |
| 2031 | | | | $ 43 |
| 2032 | | | | $ 46 |
| 2033 | | | | $ 50 |
| 2034 | | | | $ 53 |

## 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 | 2015 | 163,000 | 163,000 | EP, LNB, & OFA | 163,000 |
| Woodsdale Trenton, Ohio | B | 1 | GF/PF-GT | 5-1993 | Unknown | 82,000 | 94,000 | WI | 86,000 |
| | B | 2 | GF/PF-GT | 7-1992 | Unknown | 82,000 | 94,000 | WI | 86,000 |
| | B | 3 | GF/PF-GT | 5-1992 | Unknown | 82,000 | 94,000 | WI | 86,000 |
| | B | 4 | GF/PF-GT | 7-1992 | Unknown | 82,000 | 94,000 | WI | 86,000 |
| | B | 5 | GF/PF-GT | 5-1992 | Unknown | 82,000 | 94,000 | WI | 86,000 |
| | B | 6 | GF/PF-GT | 5-1992 | Unknown | 82,000 | 94,000 | WI | 86,000 |
| | | | | | Station Total | 492,000 | 564,000 | | 516,000 |
| | | | | SYSTEM TOTAL | | 1,069,000 | 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 Capability of Jointly Owned Generating Units

| Station Name and Location | Unit Number | Installation Date | Total MWs Summer | Total MWs Winter | Ownership Share by Company in MWs: Duke Energy Kentucky Summer | Duke Energy Kentucky Winter | DPL Summer | DPL Winter |
|---|---|---|---|---|---|---|---|---|
| East Bend<br>Boone County, KY | 2 | 3-1981 | 600 | 600 | 414 | 414 | 186 | 186 |

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 | 55,000 | 4,300,000 | -- |
| Woodsdale | -- | -- | 58,000 |

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# The Duke Energy Kentucky 2014 Integrated Resource Plan

July 1, 2014

## 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 serves approximately 138,000 customers in its approximately 300 square mile service territory, which includes the cities of Covington and Newport, Kentucky.

Duke Energy Kentucky owns an electric transmission and 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, Bracken, 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 IRPs 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. This linkage to economic activity 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. Moody's also provides a forecast of the service area economy. The Duke Energy Kentucky service area is located in Northern Kentucky adjacent to the service area of Duke Energy 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**

The service area economy consists of the employment, income, inflation, production, and population sectors, forecasts of which are provided by Moody's. Employment projections include non-agricultural, commercial, industrial, and government sectors. Income for the local economy is forecasted in several categories including wages, rents, proprietors' income, personal contributions for social insurance, and transfer payments, which are combined to produce the forecast of income less personal contributions for social insurance. Inflation is measured by changes in the Personal Consumption Price Index (PCE) for gasoline and other energy goods. Demographic projections include population and households for the Duke Kentucky territory. This information is an input to the energy and peak load forecast models.

**b. Electric Energy Forecast**

The forecast methodology recognizes that the use of energy is dependent upon key economic factors such as income, production, energy prices, historical and projected end-use appliance intensities, and 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 metropolitan region, which includes Northern Kentucky. The Duke Energy Kentucky sales forecast is developed by forecasting the energy requirements of Northern Kentucky for each customer group. These groups include the residential, commercial, industrial, governmental or other public authority, and street lighting energy sectors. Forecasts are also prepared for three minor categories: Interdepartmental Use (Gas Department), Company Use, and Losses. Similarly, the Duke Energy Kentucky peak load forecast is developed from the aforementioned energy forecast, and therefore is consistent with that of the Northern Kentucky region. The following sections provide the specifications of the econometric relationships developed to forecast electricity sales for Duke Energy Kentucky's service territory.

**Residential Sector** The forecast of total residential sales is developed by multiplying the forecasts of the number of residential customers and kWh energy usage per customer.

**Customers** The number of electric residential customers is a function of the number of projected households in the Duke Kentucky territory.

**Residential Use per Customer** Energy use per customer is a function of per capita income, real electricity prices and the combined impact of the saturation of air conditioners, electric space heating, other appliances, the efficiency of those appliances, and weather. 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 is a function of gross output, real electricity price, weather, and the combined impact of the commercial saturation of air conditioners, commercial heating, other appliances, the efficiency of those appliances, and commercial square footage. In general, electricity usage for space heating and cooling is a function of economic activity, quantified by GDP.

**Industrial Sector** Electricity use by industrial customers is primarily dependent upon the level of real gross manufacturing product (real manufacturing GDP) and the impacts of real electricity prices, electric price relative to alternate fuels, and weather.

**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. The OPA sector comprises sales to schools, government facilities, airports, and water pumping stations. Electricity sales to OPA customers are a function of governmental employment, the real price of electricity, and heating degree days.

**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 and compact fluorescent lights (CFLs)/light emitting diode lamps (LEDs).

**Total Electric Sales** Residential, Commercial, Industrial, OPA, and Street Lighting sales are combined with Interdepartmental sales to produce the projection of total electric sales.

**Total System Sendout** The forecast of total system sendout (net energy) is the combination of the total electric sales forecast and the forecasts of Company Use and system losses.

**Peak Load** Forecasts of summer and winter peak demands are developed using SAE peak demand models. The monthly peak demand model combines heating and cooling end-use estimates with peak day weather conditions, generating expected peak demand for the expected peak day. 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.

**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.

**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. First, residential, commercial, industrial, and other public authority sales are individually adjusted for the difference between actual and normal weather. Street lighting sales are not weather normalized because they are not weather sensitive. 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. Second, weather-normalized sendout is computed by summing the weather-normalized sales with non-weather sensitive sector sales. This weather-adjusted sendout is 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 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.

No major wars or energy embargoes are assumed during the forecast period. If minor conflicts and/or energy supply disruptions such as hurricanes occur, 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. The national and local economies experienced the effects of a decline in economic activity from 4Q07 to 1Q09, and flat to weak growth afterwards. Since 4Q13, economic growth has been consistently moderate in the Duke Energy Kentucky territory. The ultimate outcome in the near term is dependent upon the success of the economy sustaining this recent trend of moderate growth and the reduction of federal policy uncertainty.

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, major industries are food products, paper, printing, chemicals, steel, fabricated metals, machinery, and automotive and aircraft transportation equipment. In the non-manufacturing sector, major industries are life insurance and finance, with emerging growth sectors in health and education, leisure and hospitality, and data centers. 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 starting in 2012. This forecast incorporates impacts associated with EISA.

**b. Local**

Forecasts of employment, local population, gross product, and inflation are key indicators of economic and demographic trends. The majority of the employment growth over the forecast period occurs in the non-manufacturing sector. However, since 2013, manufacturing employment has reversed its negative trend locally, and is expected to maintain a moderate level of growth until year 2016. The rate of growth in local employment expected over the forecast will be slightly above that of the nation: 1.1% locally versus 0.8% 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. However, population in the Cincinnati metropolitan area, which Duke Energy Kentucky is part of, is projected to grow faster than the US on average, due to its diverse economy, and its ability to attract and retain young adult workers. Over the period 2014 to 2034, Duke Energy Kentucky's service area population is expected to increase at an annual average rate of 1.0%, while nationally, population is expected to grow at an annual rate of 0.6%.

The residential sector has the most existing customers and 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**

**<u>Commercial Fuels</u>** - 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, especially with the recent discovery of an abundance of natural gas reserves in the U.S. 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.

**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 seasonal characteristics promotes 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.

| Year | Customers |
|---|---|
| 2009 | 120,484 |
| 2010 | 120,826 |
| 2011 | 120,955 |
| 2012 | 121,585 |
| 2013 | 122,323 |
| 2014 | 123,687 |
| 2015 | 125,559 |
| 2016 | 127,423 |
| 2017 | 129,117 |
| 2018 | 130,734 |
| 2019 | 132,278 |
| 2020 | 133,795 |
| 2021 | 135,171 |
| 2022 | 136,528 |
| 2023 | 137,828 |
| 2024 | 139,046 |
| 2025 | 140,255 |
| 2026 | 141,461 |
| 2027 | 142,619 |
| 2028 | 143,779 |
| 2029 | 144,963 |
| 2030 | 146,141 |
| 2031 | 147,321 |
| 2032 | 148,611 |
| 2033 | 149,909 |
| 2034 | 151,186 |

**Appliance Efficiencies** - Trends in appliance efficiencies, saturations, and usage patterns impact the projected use per residential customer. 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

### 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 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. 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.

**Income** Local income data series are obtained from Moody's. 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.

**Personal Consumption Expenditure Index for Gasoline and other Energy Goods (PCE)** The PCE is obtained from Moody's.

**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 and Duke Energy Kentucky financial reports. Generally all national information is obtained from Moody's. Local weather data are obtained from the National Oceanic and Atmospheric Administration (NOAA).

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

**Megawatt-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 residential, commercial, industrial, OPA, and other sales categories.

**Number of Customers** The number of customers by class by month is obtained from Company records.

**Use Per Customer** Average use per customer by month is computed 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 consists of appliance efficiencies, saturations, and energy consumption values.

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, electric heat pump, and miscellaneous uses such as 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 forecast appliance efficiency and forecast saturation are obtained from Itron, Inc., a forecast consulting firm. Itron has developed 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 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 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 national and local employment, income, gross product, and population are provided by Moody's. Projections of electricity and natural gas prices are provided by the Company's Financial Planning and Analysis department and Moody's.

### 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 average demands are less than 500 kW.

Duke Energy Kentucky periodically monitors selected end-uses or systems associated with evaluations of EE programs. These studies are performed as necessary and are typically of short 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 studies of customer satisfaction, appliance saturation studies, end-use, and competition (to monitor customer switching percentages in order to forecast future utility load); and related marketing research projects.

## 5. MODELS

Specific analytical techniques were 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 independent variables, qualitative variables are employed to account for the impact of the outliers. 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 same forecasting methodology as it has for the past several years, and considers these methods to be adequate.

### d. Methodology Enhancements

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.

The SAE Modeling Specification is now the principle modeling technique employed to estimate economic/behavioral relationships among the relevant variables for the residential and commercial classes. In addition to the advantages generated by the regression technique, the SAE approach also allows the model to generate energy and peak forecasts that incorporates the impacts from appliance end-use saturation and efficiency trends.

**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 MetrixND software from Itron, Inc.

**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 reductions for either EE or DR. The term "Native" refers to the Internal forecast reduced by DR.

**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, 0.8 percent per year; and Industrial use, 0.9 percent per year. The summation of the forecast across all sectors and including losses results in a growth rate forecast of 0.9 percent for Net Energy for Load.

After implementation of new EE programs and incremental EE impacts (Figure B-2), Residential use is expected to increase an average of 0.8 percent per year; Commercial use, 0.3 percent per year; and Industrial use, 0.9 percent per year. The summation of the forecast across all sectors 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 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 are shown in Figure B-4. The projected growth in the summer peak is 0.6 percent. Projected growth in winter peak demand is 0.7 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 discussion of the impacts of DR programs.

**d. Load Factor**

The table 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-3, before EE.

| YEAR | LOAD FACTOR |
|---|---|
| 2009 | 56.7% |
| 2010 | 54.3% |
| 2011 | 56.0% |
| 2012 | 56.0% |
| 2013 | 59.3% |
| 2014 | 60.1% |
| 2015 | 58.9% |
| 2016 | 59.1% |
| 2017 | 59.5% |
| 2018 | 59.7% |
| 2019 | 59.9% |
| 2020 | 59.9% |
| 2021 | 59.7% |
| 2022 | 59.7% |
| 2023 | 59.7% |
| 2024 | 59.7% |
| 2025 | 59.7% |
| 2026 | 59.8% |
| 2027 | 59.8% |
| 2028 | 59.8% |
| 2029 | 59.8% |
| 2030 | 59.9% |
| 2031 | 59.9% |
| 2032 | 60.0% |
| 2033 | 60.0% |
| 2034 | 60.0% |

**e. Range of Forecasts**

Assuming normal weather, the most likely forecast of electrical energy demand and peak loads is determined from 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 a 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 a relatively optimistic scenario about the future growth of Duke Energy Kentucky sales while the lower band reflects a pessimistic scenario.

Figure B-5 provides the high, low, and most likely before EE forecasts of electric energy and peak demand for the service area. Figure B-6 provides similar information after implementation of the EE programs.

**f. Monthly Forecast**

Figures B-7 through Figure B-10 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
DUKE ENERGY KENTUCKY SYSTEM
SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)
BEFORE EE

| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | (1+2+3+4+5+6) | | (7+8) |
| | Year | Rural and Residential | Commercial | Industrial | Steet-Hwy Lighting | Sales for Resale[a] | Other | Total Consumption | Losses and Unaccounted For[b] | Net Energy for Load |
| -5 | 2009 | 1,410,347 | 1,395,345 | 730,917 | 15,348 | 0 | 301,793 | 3,853,751 | 162,419 | 4,016,170 |
| -4 | 2010 | 1,550,929 | 1,451,523 | 782,132 | 15,167 | 0 | 313,648 | 4,113,400 | 133,325 | 4,246,725 |
| -3 | 2011 | 1,502,121 | 1,431,860 | 787,055 | 15,226 | 0 | 302,479 | 4,038,740 | 158,714 | 4,197,454 |
| -2 | 2012 | 1,450,472 | 1,440,387 | 777,513 | 15,006 | 0 | 297,913 | 3,981,291 | 201,067 | 4,182,359 |
| -1 | 2013 | 1,465,361 | 1,454,627 | 808,831 | 15,362 | 0 | 291,017 | 4,035,197 | 277,308 | 4,312,505 |
| 0 | 2014 | 1,500,327 | 1,481,419 | 814,340 | 15,720 | 0 | 308,207 | 4,120,014 | 375,480 | 4,495,494 |
| 1 | 2015 | 1,516,492 | 1,499,423 | 834,419 | 15,285 | 0 | 323,536 | 4,189,154 | 310,710 | 4,499,864 |
| 2 | 2016 | 1,557,424 | 1,510,968 | 846,062 | 15,318 | 0 | 327,459 | 4,257,231 | 319,113 | 4,576,344 |
| 3 | 2017 | 1,581,412 | 1,516,197 | 854,714 | 15,350 | 0 | 329,152 | 4,296,825 | 324,638 | 4,621,462 |
| 4 | 2018 | 1,603,319 | 1,523,646 | 863,699 | 15,383 | 0 | 329,682 | 4,335,729 | 330,988 | 4,666,717 |
| 5 | 2019 | 1,623,034 | 1,533,979 | 872,996 | 15,416 | 0 | 329,656 | 4,375,081 | 338,479 | 4,713,560 |
| 6 | 2020 | 1,634,267 | 1,544,827 | 881,754 | 15,449 | 0 | 329,734 | 4,406,031 | 340,575 | 4,746,606 |
| 7 | 2021 | 1,637,754 | 1,551,633 | 890,374 | 15,482 | 0 | 329,911 | 4,425,154 | 342,637 | 4,767,791 |
| 8 | 2022 | 1,649,541 | 1,561,787 | 899,064 | 15,515 | 0 | 330,091 | 4,455,998 | 348,151 | 4,804,148 |
| 9 | 2023 | 1,661,793 | 1,573,314 | 907,202 | 15,547 | 0 | 329,984 | 4,487,841 | 355,556 | 4,843,397 |
| 10 | 2024 | 1,677,268 | 1,588,322 | 914,160 | 15,580 | 0 | 329,799 | 4,525,129 | 363,521 | 4,888,651 |
| 11 | 2025 | 1,686,119 | 1,599,031 | 920,529 | 15,613 | 0 | 329,592 | 4,550,884 | 371,160 | 4,922,043 |
| 12 | 2026 | 1,700,774 | 1,613,480 | 926,203 | 15,646 | 0 | 329,669 | 4,585,772 | 379,664 | 4,965,436 |
| 13 | 2027 | 1,718,493 | 1,630,232 | 932,116 | 15,679 | 0 | 329,987 | 4,626,507 | 389,706 | 5,016,213 |
| 14 | 2028 | 1,741,797 | 1,651,123 | 937,827 | 15,712 | 0 | 330,796 | 4,677,255 | 402,612 | 5,079,867 |
| 15 | 2029 | 1,755,812 | 1,666,692 | 943,526 | 15,745 | 0 | 331,660 | 4,713,435 | 412,646 | 5,126,081 |
| 16 | 2030 | 1,773,949 | 1,683,006 | 949,134 | 15,777 | 0 | 332,526 | 4,754,392 | 422,249 | 5,176,642 |
| 17 | 2031 | 1,795,244 | 1,700,696 | 955,828 | 15,810 | 0 | 333,351 | 4,800,929 | 434,678 | 5,235,607 |
| 18 | 2032 | 1,823,409 | 1,722,291 | 961,757 | 15,843 | 0 | 334,466 | 4,857,765 | 447,348 | 5,305,114 |
| 19 | 2033 | 1,845,676 | 1,739,100 | 967,765 | 15,876 | 0 | 335,725 | 4,904,143 | 457,241 | 5,361,383 |
| 20 | 2034 | 1,872,209 | 1,758,377 | 973,250 | 15,909 | 0 | 337,225 | 4,956,970 | 454,160 | 5,411,130 |

(a) Sales for resale to municipals.
(b) Transmission, transformer and other losses and energy unaccounted for.

FIGURE B-2
DUKE ENERGY KENTUCKY SYSTEM
SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)[a]
AFTER EE

| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|---|---|
| | Year | Rural and Residential | Commercial | Industrial | Steet-Hwy Lighting | Sales for Resale[b] | Other | (1+2+3+4+5+6) Total Consumption | Losses and Unaccounted For[c] | (7+8) Net Energy for Load |
| -5 | 2009 | 1,410,347 | 1,395,345 | 730,917 | 15,348 | 0 | 301,793 | 3,853,751 | 162,419 | 4,016,170 |
| -4 | 2010 | 1,550,929 | 1,451,523 | 782,132 | 15,167 | 0 | 313,648 | 4,113,400 | 133,325 | 4,246,725 |
| -3 | 2011 | 1,502,121 | 1,431,860 | 787,055 | 15,226 | 0 | 302,479 | 4,038,740 | 158,714 | 4,197,454 |
| -2 | 2012 | 1,450,472 | 1,440,387 | 777,513 | 15,006 | 0 | 297,913 | 3,981,291 | 201,067 | 4,182,359 |
| -1 | 2013 | 1,465,361 | 1,454,627 | 808,831 | 15,362 | 0 | 291,017 | 4,035,197 | 277,308 | 4,312,505 |
| 0 | 2014 | 1,497,963 | 1,478,002 | 814,340 | 15,720 | 0 | 307,450 | 4,113,475 | 374,546 | 4,488,021 |
| 1 | 2015 | 1,508,790 | 1,488,567 | 834,419 | 15,285 | 0 | 321,184 | 4,168,245 | 308,777 | 4,477,022 |
| 2 | 2016 | 1,544,643 | 1,492,309 | 846,062 | 15,318 | 0 | 323,424 | 4,221,756 | 315,434 | 4,537,190 |
| 3 | 2017 | 1,563,564 | 1,488,555 | 854,714 | 15,350 | 0 | 323,154 | 4,245,337 | 320,022 | 4,565,359 |
| 4 | 2018 | 1,580,401 | 1,486,236 | 863,699 | 15,383 | 0 | 321,518 | 4,267,238 | 325,994 | 4,593,232 |
| 5 | 2019 | 1,594,823 | 1,486,256 | 872,996 | 15,416 | 0 | 319,172 | 4,288,662 | 333,712 | 4,622,374 |
| 6 | 2020 | 1,600,944 | 1,486,944 | 881,754 | 15,449 | 0 | 316,928 | 4,302,018 | 335,700 | 4,637,719 |
| 7 | 2021 | 1,599,584 | 1,483,759 | 890,374 | 15,482 | 0 | 314,780 | 4,303,978 | 337,225 | 4,641,203 |
| 8 | 2022 | 1,606,761 | 1,483,814 | 899,064 | 15,515 | 0 | 312,634 | 4,317,788 | 342,071 | 4,659,860 |
| 9 | 2023 | 1,614,263 | 1,485,248 | 907,202 | 15,547 | 0 | 310,199 | 4,332,460 | 348,948 | 4,681,408 |
| 10 | 2024 | 1,625,010 | 1,490,141 | 914,160 | 15,580 | 0 | 307,684 | 4,352,576 | 356,384 | 4,708,960 |
| 11 | 2025 | 1,629,130 | 1,490,648 | 920,529 | 15,613 | 0 | 305,145 | 4,361,065 | 363,588 | 4,724,652 |
| 12 | 2026 | 1,638,979 | 1,494,777 | 926,203 | 15,646 | 0 | 302,890 | 4,378,495 | 371,849 | 4,750,344 |
| 13 | 2027 | 1,651,784 | 1,501,103 | 932,116 | 15,679 | 0 | 300,873 | 4,401,554 | 381,865 | 4,783,420 |
| 14 | 2028 | 1,670,075 | 1,511,467 | 937,827 | 15,712 | 0 | 299,345 | 4,434,425 | 394,947 | 4,829,373 |
| 15 | 2029 | 1,678,964 | 1,516,411 | 943,526 | 15,745 | 0 | 297,872 | 4,452,517 | 405,370 | 4,857,887 |
| 16 | 2030 | 1,691,868 | 1,522,004 | 949,134 | 15,777 | 0 | 296,398 | 4,475,182 | 415,565 | 4,890,746 |
| 17 | 2031 | 1,707,813 | 1,528,873 | 955,828 | 15,810 | 0 | 294,880 | 4,503,204 | 428,807 | 4,932,010 |
| 18 | 2032 | 1,730,514 | 1,539,593 | 961,757 | 15,843 | 0 | 293,651 | 4,541,358 | 442,459 | 4,983,817 |
| 19 | 2033 | 1,747,258 | 1,545,451 | 967,765 | 15,876 | 0 | 292,563 | 4,568,913 | 453,473 | 5,022,386 |
| 20 | 2034 | 1,771,527 | 1,560,935 | 973,250 | 15,909 | 0 | 293,415 | 4,615,036 | 472,240 | 5,087,276 |

(a) Includes EE Impacts
(b) Sales for resale to municipals.
(c) Transmission, transformer and other losses and energy unaccounted for.

FIGURE B-3
DUKE ENERGY KENTUCKY SYSTEM
SEASONAL PEAK LOAD FORECAST (MEGAWATTS)
BEFORE EE
INTERNAL LOAD[a]

| | | SUMMER | | | WINTER[d] | | |
|---|---|---|---|---|---|---|---|
| | YEAR | LOAD | CHANGE[b] | PERCENT CHANGE[c] | LOAD | CHANGE[b] | PERCENT CHANGE[c] |
| -5 | 2009 | 808 | | | 671 | | |
| -4 | 2010 | 899 | 91 | 11.3% | 689 | 18 | 2.7% |
| -3 | 2011 | 886 | (13) | -1.4% | 712 | 23 | 3.3% |
| -2 | 2012 | 871 | (15) | -1.6% | 672 | (40) | -5.6% |
| -1 | 2013 | 871 | (0) | 0.0% | 758 | 86 | 12.8% |
| 0 | 2014 | 886 | 15 | 1.7% | 717 | (41) | -5.4% |
| 1 | 2015 | 899 | 13 | 1.5% | 731 | 14 | 1.9% |
| 2 | 2016 | 912 | 13 | 1.4% | 738 | 7 | 0.9% |
| 3 | 2017 | 920 | 8 | 0.9% | 744 | 7 | 0.9% |
| 4 | 2018 | 928 | 8 | 0.8% | 751 | 7 | 0.9% |
| 5 | 2019 | 936 | 8 | 0.9% | 754 | 3 | 0.4% |
| 6 | 2020 | 943 | 7 | 0.7% | 755 | 1 | 0.1% |
| 7 | 2021 | 949 | 6 | 0.7% | 759 | 4 | 0.5% |
| 8 | 2022 | 956 | 7 | 0.7% | 763 | 4 | 0.6% |
| 9 | 2023 | 963 | 7 | 0.8% | 769 | 6 | 0.8% |
| 10 | 2024 | 972 | 8 | 0.8% | 772 | 3 | 0.4% |
| 11 | 2025 | 978 | 7 | 0.7% | 777 | 5 | 0.7% |
| 12 | 2026 | 986 | 8 | 0.8% | 784 | 6 | 0.8% |
| 13 | 2027 | 996 | 10 | 1.0% | 792 | 9 | 1.1% |
| 14 | 2028 | 1,007 | 11 | 1.1% | 797 | 5 | 0.7% |
| 15 | 2029 | 1,016 | 9 | 0.9% | 804 | 6 | 0.8% |
| 16 | 2030 | 1,025 | 9 | 0.9% | 811 | 8 | 1.0% |
| 17 | 2031 | 1,036 | 10 | 1.0% | 821 | 10 | 1.2% |
| 18 | 2032 | 1,047 | 12 | 1.2% | 828 | 7 | 0.9% |
| 19 | 2033 | 1,058 | 11 | 1.0% | 835 | 7 | 0.8% |
| 20 | 2034 | 1,068 | 10 | 0.9% | 842 | 7 | 0.8% |

(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-4
DUKE ENERGY KENTUCKY SYSTEM
SEASONAL PEAK LOAD FORECAST (MEGAWATTS)[a]
AFTER EE
INTERNAL LOAD[b]

| | | SUMMER | | | WINTER[d] | | |
|---|---|---|---|---|---|---|---|
| | YEAR | LOAD | CHANGE[b] | PERCENT CHANGE[c] | LOAD | CHANGE[b] | PERCENT CHANGE[c] |
| -5 | 2009 | 881 | | | 738 | | |
| -4 | 2010 | 930 | 49 | 5.6% | 725 | (13) | -1.8% |
| -3 | 2011 | 886 | (44) | -4.7% | 712 | (13) | -1.8% |
| -2 | 2012 | 871 | (15) | -1.6% | 672 | (40) | -5.6% |
| -1 | 2013 | 871 | (0) | 0.0% | 758 | 86 | 12.8% |
| 0 | 2014 | 884 | 13 | 1.5% | 716 | (42) | -5.6% |
| 1 | 2015 | 894 | 10 | 1.1% | 728 | 13 | 1.8% |
| 2 | 2016 | 903 | 9 | 1.0% | 733 | 5 | 0.7% |
| 3 | 2017 | 908 | 5 | 0.5% | 739 | 5 | 0.7% |
| 4 | 2018 | 912 | 4 | 0.4% | 744 | 5 | 0.7% |
| 5 | 2019 | 917 | 5 | 0.5% | 746 | 2 | 0.2% |
| 6 | 2020 | 920 | 3 | 0.3% | 745 | (0) | 0.0% |
| 7 | 2021 | 922 | 2 | 0.2% | 748 | 3 | 0.4% |
| 8 | 2022 | 925 | 3 | 0.3% | 751 | 3 | 0.4% |
| 9 | 2023 | 928 | 3 | 0.4% | 756 | 5 | 0.6% |
| 10 | 2024 | 932 | 4 | 0.4% | 759 | 2 | 0.3% |
| 11 | 2025 | 935 | 3 | 0.3% | 763 | 4 | 0.6% |
| 12 | 2026 | 939 | 4 | 0.4% | 768 | 5 | 0.7% |
| 13 | 2027 | 944 | 5 | 0.6% | 776 | 8 | 1.0% |
| 14 | 2028 | 952 | 8 | 0.9% | 780 | 4 | 0.5% |
| 15 | 2029 | 959 | 7 | 0.7% | 785 | 5 | 0.6% |
| 16 | 2030 | 966 | 7 | 0.7% | 791 | 7 | 0.9% |
| 17 | 2031 | 968 | 2 | 0.2% | 800 | 9 | 1.1% |
| 18 | 2032 | 984 | 16 | 1.7% | 806 | 6 | 0.7% |
| 19 | 2033 | 992 | 8 | 0.8% | 817 | 10 | 1.3% |
| 20 | 2034 | 1,004 | 12 | 1.2% | 822 | 5 | 0.6% |

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

FIGURE B-5
DUKE ENERGY KENTUCKY SYSTEM
RANGE OF FORECASTS
ECONOMIC BANDS

| | ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD) BEFORE EE | | | PEAK LOAD FORECAST (MW) INTERNAL[a] BEFORE EE | | |
|---|---|---|---|---|---|---|
| YEAR | LOW | MOST LIKELY | HIGH | LOW | MOST LIKELY | HIGH |
| 2014 | 4,282 | 4,495 | 4,709 | 838 | 886 | 934 |
| 2015 | 4,286 | 4,500 | 4,714 | 851 | 899 | 947 |
| 2016 | 4,362 | 4,576 | 4,790 | 863 | 912 | 960 |
| 2017 | 4,408 | 4,621 | 4,835 | 872 | 920 | 968 |
| 2018 | 4,453 | 4,667 | 4,881 | 879 | 928 | 976 |
| 2019 | 4,500 | 4,714 | 4,927 | 888 | 936 | 984 |
| 2020 | 4,533 | 4,747 | 4,960 | 894 | 943 | 991 |
| 2021 | 4,554 | 4,768 | 4,982 | 901 | 949 | 997 |
| 2022 | 4,590 | 4,804 | 5,018 | 908 | 956 | 1,004 |
| 2023 | 4,630 | 4,843 | 5,057 | 915 | 963 | 1,012 |
| 2024 | 4,675 | 4,889 | 5,103 | 923 | 972 | 1,020 |
| 2025 | 4,708 | 4,922 | 5,136 | 930 | 978 | 1,027 |
| 2026 | 4,752 | 4,965 | 5,179 | 938 | 986 | 1,035 |
| 2027 | 4,802 | 5,016 | 5,230 | 948 | 996 | 1,044 |
| 2028 | 4,866 | 5,080 | 5,294 | 959 | 1,007 | 1,055 |
| 2029 | 4,912 | 5,126 | 5,340 | 968 | 1,016 | 1,064 |
| 2030 | 4,963 | 5,177 | 5,391 | 977 | 1,025 | 1,074 |
| 2031 | 5,022 | 5,236 | 5,449 | 987 | 1,036 | 1,084 |
| 2032 | 5,091 | 5,305 | 5,519 | 999 | 1,047 | 1,096 |
| 2033 | 5,148 | 5,361 | 5,575 | 1,010 | 1,058 | 1,106 |
| 2034 | 5,197 | 5,411 | 5,625 | 1,019 | 1,068 | 1,116 |

(a) Includes controllable load.

FIGURE B-6
DUKE ENERGY KENTUCKY SYSTEM
RANGE OF FORECASTS[a]
ECONOMIC BANDS

| | ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD) AFTER EE | | | PEAK LOAD FORECAST (MW) INTERNAL[b] AFTER EE | | |
|---|---|---|---|---|---|---|
| YEAR | LOW | MOST LIKELY | HIGH | LOW | MOST LIKELY | HIGH |
| 2014 | 4,274 | 4,488 | 4,702 | 836 | 884 | 932 |
| 2015 | 4,263 | 4,477 | 4,691 | 846 | 894 | 942 |
| 2016 | 4,323 | 4,537 | 4,751 | 855 | 903 | 952 |
| 2017 | 4,351 | 4,565 | 4,779 | 860 | 908 | 956 |
| 2018 | 4,379 | 4,593 | 4,807 | 864 | 912 | 960 |
| 2019 | 4,408 | 4,622 | 4,836 | 868 | 917 | 965 |
| 2020 | 4,424 | 4,638 | 4,852 | 871 | 920 | 968 |
| 2021 | 4,427 | 4,641 | 4,855 | 873 | 922 | 970 |
| 2022 | 4,446 | 4,660 | 4,874 | 876 | 925 | 973 |
| 2023 | 4,468 | 4,681 | 4,895 | 880 | 928 | 976 |
| 2024 | 4,495 | 4,709 | 4,923 | 884 | 932 | 980 |
| 2025 | 4,511 | 4,725 | 4,939 | 886 | 935 | 983 |
| 2026 | 4,536 | 4,750 | 4,964 | 890 | 939 | 987 |
| 2027 | 4,570 | 4,783 | 4,997 | 896 | 944 | 992 |
| 2028 | 4,615 | 4,829 | 5,043 | 904 | 952 | 1,001 |
| 2029 | 4,644 | 4,858 | 5,072 | 911 | 959 | 1,007 |
| 2030 | 4,677 | 4,891 | 5,105 | 918 | 966 | 1,014 |
| 2031 | 4,718 | 4,932 | 5,146 | 919 | 968 | 1,016 |
| 2032 | 4,770 | 4,984 | 5,198 | 935 | 984 | 1,032 |
| 2033 | 4,809 | 5,022 | 5,236 | 943 | 992 | 1,040 |
| 2034 | 4,873 | 5,087 | 5,301 | 956 | 1,004 | 1,052 |

(a) Includes EE impacts
(b) Includes controllable load.

FIGURE B-7
DUKE ENERGY KENTUCKY SYSTEM
NET MONTHLY ENERGY AND PEAK FORECAST
BEFORE EE

| YEAR 0 | 2014 | ENERGY, MWH | PEAK, MW |
|---|---|---|---|
| January | | 416,952 | 715 |
| February | | 380,708 | 688 |
| March | | 369,464 | 627 |
| April | | 319,699 | 568 |
| May | | 343,514 | 707 |
| June | | 389,359 | 834 |
| July | | 432,750 | 848 |
| August | | 431,617 | 886 |
| September | | 354,123 | 811 |
| October | | 326,968 | 587 |
| November | | 341,937 | 621 |
| December | | 388,404 | 667 |
| | | | |
| YEAR 1 | 2015 | | |
| January | | 394,661 | 717 |
| February | | 366,334 | 691 |
| March | | 353,816 | 632 |
| April | | 322,480 | 574 |
| May | | 349,354 | 718 |
| June | | 396,031 | 846 |
| July | | 440,543 | 861 |
| August | | 439,386 | 899 |
| September | | 360,479 | 822 |
| October | | 332,883 | 597 |
| November | | 348,468 | 629 |
| December | | 395,431 | 674 |

FIGURE B-8
DUKE ENERGY KENTUCKY SYSTEM
NET MONTHLY ENERGY AND PEAK FORECAST
AFTER EE

| YEAR 0 | 2014 | ENERGY, MWH | PEAK, MW |
|---|---|---|---|
| January | | 416,845 | 715 |
| February | | 380,523 | 687 |
| March | | 369,188 | 627 |
| April | | 319,375 | 567 |
| May | | 343,051 | 706 |
| June | | 388,742 | 832 |
| July | | 431,980 | 847 |
| August | | 430,749 | 884 |
| September | | 353,295 | 809 |
| October | | 326,139 | 586 |
| November | | 340,961 | 620 |
| December | | 387,173 | 666 |
| | | | |
| YEAR 1 | 2015 | | |
| January | | 393,058 | 716 |
| February | | 364,864 | 688 |
| March | | 352,283 | 630 |
| April | | 321,066 | 571 |
| May | | 347,639 | 714 |
| June | | 394,040 | 841 |
| July | | 438,317 | 856 |
| August | | 437,094 | 894 |
| September | | 358,430 | 818 |
| October | | 330,965 | 593 |
| November | | 346,341 | 627 |
| December | | 392,924 | 671 |

FIGIRE B-9
DUKE ENERGY KENTUCKY SYSTEM
SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS./YEAR)
BEFORE EE

| Year 0 | 2014 | (1) Rural and Residential | (2) Commercial | (3) Industrial | (4) Steet-Hwy Lighting | (5) Sales for Resale[a] | (6) Other | (7) (1+2+3+4+5+6) Total Consumption | (8) Losses and Unaccounted For[b] | (9) (7+8) Net Energy for Load |
|---|---|---|---|---|---|---|---|---|---|---|
| January | | 170,281 | 120,993 | 66,189 | 1,314 | 0 | 27,932 | 386,709 | 30,243 | 416,952 |
| February | | 142,107 | 113,920 | 65,652 | 1,345 | 0 | 26,168 | 349,192 | 31,516 | 380,708 |
| March | | 114,423 | 119,083 | 65,663 | 1,255 | 0 | 24,975 | 325,398 | 44,066 | 369,464 |
| April | | 90,126 | 114,155 | 65,606 | 1,302 | 0 | 24,590 | 295,779 | 23,920 | 319,699 |
| May | | 102,482 | 123,025 | 67,567 | 1,177 | 0 | 25,373 | 319,625 | 23,889 | 343,514 |
| June | | 132,623 | 131,371 | 70,741 | 1,260 | 0 | 26,271 | 362,267 | 27,092 | 389,359 |
| July | | 157,957 | 143,237 | 72,543 | 1,207 | 0 | 27,973 | 402,917 | 29,834 | 432,750 |
| August | | 155,583 | 142,428 | 74,661 | 1,243 | 0 | 27,943 | 401,858 | 29,759 | 431,617 |
| September | | 107,844 | 123,850 | 71,068 | 1,256 | 0 | 25,742 | 329,760 | 24,364 | 354,123 |
| October | | 92,321 | 117,918 | 67,759 | 1,278 | 0 | 25,339 | 304,614 | 22,354 | 326,968 |
| November | | 106,874 | 115,899 | 68,093 | 1,287 | 0 | 26,041 | 318,194 | 23,743 | 341,937 |
| December | | 142,422 | 122,631 | 67,425 | 1,316 | 0 | 27,816 | 361,610 | 26,795 | 388,404 |
| YEAR 1 | 2015 | | | | | | | | | |
| January | | 150,439 | 122,389 | 66,044 | 1,329 | 0 | 27,382 | 367,582 | 27,079 | 394,661 |
| February | | 133,214 | 113,962 | 65,724 | 1,348 | 0 | 26,416 | 340,664 | 25,670 | 366,334 |
| March | | 117,116 | 119,704 | 65,770 | 1,258 | 0 | 25,802 | 329,650 | 24,165 | 353,816 |
| April | | 92,378 | 115,289 | 66,152 | 1,305 | 0 | 25,437 | 300,561 | 21,919 | 322,480 |
| May | | 105,096 | 123,990 | 68,464 | 1,180 | 0 | 26,210 | 324,939 | 24,414 | 349,354 |
| June | | 136,044 | 132,354 | 71,892 | 1,263 | 0 | 27,110 | 368,663 | 27,368 | 396,031 |
| July | | 162,040 | 144,157 | 73,884 | 1,209 | 0 | 28,776 | 410,067 | 30,476 | 440,543 |
| August | | 159,594 | 143,357 | 76,064 | 1,246 | 0 | 28,721 | 408,982 | 30,403 | 439,386 |
| September | | 110,610 | 124,825 | 72,528 | 1,258 | 0 | 26,486 | 335,707 | 24,772 | 360,479 |
| October | | 94,639 | 118,923 | 69,263 | 1,281 | 0 | 26,042 | 310,148 | 22,735 | 332,883 |
| November | | 109,490 | 116,886 | 69,632 | 1,290 | 0 | 26,716 | 324,014 | 24,453 | 348,468 |
| December | | 145,832 | 123,587 | 69,002 | 1,319 | 0 | 28,437 | 368,175 | 27,255 | 395,431 |

(a) Sales for resale to municipals.
(b) Transmission, transformer and other losses and energy unaccounted for.

FIGIRE B-10
DUKE ENERGY KENTUCKY SYSTEM
SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS./YEAR)
AFTER EE

| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | (1+2+3+4+5+6) | | |
| | | Rural and | | | Steet-Hwy | Sales for | | Total | Losses and | (7+8) |
| Year 0 | 2014 | Residential | Commercial | Industrial | Lighting | Resale[a] | Other | Consumption | Unaccounted For[b] | Net Energy for Load |
| January | | 170,246 | 120,950 | 66,189 | 1,314 | 0 | 27,915 | 386,614 | 30,338 | 416,952 |
| February | | 142,043 | 113,841 | 65,652 | 1,345 | 0 | 26,143 | 349,024 | 31,684 | 380,708 |
| March | | 114,335 | 118,942 | 65,663 | 1,255 | 0 | 24,938 | 325,133 | 44,331 | 369,464 |
| April | | 90,039 | 113,972 | 65,606 | 1,302 | 0 | 24,545 | 295,464 | 24,235 | 319,699 |
| May | | 102,345 | 122,769 | 67,567 | 1,177 | 0 | 25,313 | 319,171 | 24,342 | 343,514 |
| June | | 132,395 | 131,070 | 70,741 | 1,260 | 0 | 26,202 | 361,670 | 27,689 | 389,359 |
| July | | 157,658 | 142,876 | 72,543 | 1,207 | 0 | 27,892 | 402,176 | 30,575 | 432,750 |
| August | | 155,254 | 142,020 | 74,661 | 1,243 | 0 | 27,853 | 401,031 | 30,585 | 431,617 |
| September | | 107,589 | 123,419 | 71,068 | 1,256 | 0 | 25,647 | 328,979 | 25,145 | 354,123 |
| October | | 92,099 | 117,462 | 67,759 | 1,278 | 0 | 25,240 | 303,837 | 23,131 | 326,968 |
| November | | 106,550 | 115,422 | 68,093 | 1,287 | 0 | 25,938 | 317,288 | 24,648 | 341,937 |
| December | | 141,939 | 122,088 | 67,425 | 1,316 | 0 | 27,699 | 360,468 | 27,937 | 388,404 |
| | | | | | | | | | | |
| YEAR 1 | 2015 | | | | | | | | | |
| January | | 149,725 | 121,792 | 66,044 | 1,329 | 0 | 27,247 | 366,136 | 28,525 | 394,661 |
| February | | 132,607 | 113,379 | 65,724 | 1,348 | 0 | 26,284 | 339,343 | 26,992 | 366,334 |
| March | | 116,580 | 119,000 | 65,770 | 1,258 | 0 | 25,646 | 328,253 | 25,562 | 353,816 |
| April | | 91,982 | 114,555 | 66,152 | 1,305 | 0 | 25,275 | 299,268 | 23,212 | 322,480 |
| May | | 104,579 | 123,114 | 68,464 | 1,180 | 0 | 26,019 | 323,356 | 25,997 | 349,354 |
| June | | 135,318 | 131,437 | 71,892 | 1,263 | 0 | 26,911 | 366,821 | 29,210 | 396,031 |
| July | | 161,201 | 143,150 | 73,884 | 1,209 | 0 | 28,560 | 408,005 | 32,538 | 440,543 |
| August | | 158,768 | 142,294 | 76,064 | 1,246 | 0 | 28,494 | 406,865 | 32,520 | 439,386 |
| September | | 110,024 | 123,760 | 72,528 | 1,258 | 0 | 26,258 | 333,828 | 26,651 | 360,479 |
| October | | 94,183 | 117,857 | 69,263 | 1,281 | 0 | 25,814 | 308,398 | 24,484 | 332,883 |
| November | | 108,860 | 115,812 | 69,632 | 1,290 | 0 | 26,487 | 322,080 | 26,387 | 348,468 |
| December | | 144,964 | 122,416 | 69,002 | 1,319 | 0 | 28,189 | 365,889 | 29,542 | 395,431 |

(a) Sales for resale to municipals.
(b) 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 |
|---|---|---|---|---|---|
| 2009 | 119,747 | 13,318 | 383 | 392 | 979 |
| 2010 | 120,099 | 13,355 | 382 | 400 | 977 |
| 2011 | 120,423 | 13,396 | 379 | 408 | 968 |
| 2012 | 121,088 | 13,528 | 380 | 415 | 966 |
| 2013 | 121,661 | 13,689 | 378 | 431 | 956 |
| 2014 | 122,727 | 13,850 | 375 | 431 | 964 |
| 2015 | 124,386 | 14,052 | 373 | 436 | 991 |
| 2016 | 126,311 | 14,284 | 371 | 442 | 1,003 |
| 2017 | 128,045 | 14,494 | 369 | 448 | 1,009 |
| 2018 | 129,723 | 14,695 | 367 | 453 | 1,012 |
| 2019 | 131,274 | 14,880 | 365 | 459 | 1,014 |
| 2020 | 132,826 | 15,063 | 363 | 464 | 1,015 |
| 2021 | 134,254 | 15,231 | 362 | 469 | 1,017 |
| 2022 | 135,622 | 15,391 | 360 | 474 | 1,019 |
| 2023 | 136,950 | 15,545 | 358 | 479 | 1,021 |
| 2024 | 138,209 | 15,691 | 356 | 483 | 1,023 |
| 2025 | 139,406 | 15,829 | 354 | 487 | 1,025 |
| 2026 | 140,628 | 15,969 | 352 | 492 | 1,028 |
| 2027 | 141,801 | 16,104 | 350 | 496 | 1,032 |
| 2028 | 142,961 | 16,236 | 348 | 500 | 1,036 |
| 2029 | 144,127 | 16,369 | 346 | 504 | 1,042 |
| 2030 | 145,321 | 16,505 | 344 | 508 | 1,047 |
| 2031 | 146,482 | 16,637 | 342 | 512 | 1,052 |
| 2032 | 147,728 | 16,779 | 340 | 516 | 1,058 |
| 2033 | 149,024 | 16,926 | 338 | 521 | 1,065 |
| 2034 | 150,314 | 17,072 | 337 | 525 | 1,073 |

NOTE: 2014 FIGURES REPRESENT AVERAGE TWELVE MONTH FORECAST

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

DUKE ENERGY KENTUCKY SYSTEM
WEATHER NORMALIZED
ANNUAL ENERGY (MWh)

| | RESIDENTIAL | COMMERCIAL | INDUSTRIAL | STREET LIGHTING | OTHER PUBLIC AUTHORITY | INTER DEPARTMENT | COMPANY USE | TOTAL COMSUMPTION | LOSSES AND UNACCOUNTED FOR | NET ENERGY FOR LOAD |
|---|---|---|---|---|---|---|---|---|---|---|
| 2009 | 1,449,746 | 1,405,926 | 731,987 | 15,348 | 302,864 | 751 | 887 | 3,907,509 | 150,730 | 4,058,239 |
| 2010 | 1,457,154 | 1,422,179 | 775,492 | 15,167 | 304,419 | 885 | 818 | 3,976,114 | 110,867 | 4,086,981 |
| 2011 | 1,472,941 | 1,410,733 | 782,918 | 15,226 | 295,502 | 714 | 451 | 3,978,485 | 156,364 | 4,134,849 |
| 2012 | 1,466,862 | 1,440,666 | 778,998 | 15,006 | 294,619 | 855 | 786 | 3,997,792 | 201,940 | 4,199,732 |
| 2013 | 1,452,447 | 1,461,534 | 811,968 | 15,362 | 288,525 | 873 | 720 | 4,031,429 | 277,098 | 4,308,527 |

DUKE ENERGY KENTUCKY SYSTEM
WEATHER NORMALIZED
AND Peaks (MW)

| | SUMMER PEAK (MW) | WNITER PEAK (MW) |
|---|---|---|
| 2009 | 875 | 725 |
| 2010 | 879 | 719 |
| 2011 | 886 | 712 |
| 2012 | 871 | 671 |
| 2013 | 871 | 758 |

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 |

Section 7.(7).a cont.

| | |
|---|---|
| @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 |

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# The Duke Energy Kentucky 2014 Integrated Resource Plan

## July 1, 2014

## Appendix C – Demand Side Management

## APPENDIX C – DEMAND SIDE MANAGEMENT

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## C. DEMAND-SIDE MANAGEMENT RESOURCES

### 1. INTRODUCTION

Duke Energy Kentucky offers the following DSM[5] programs that have been developed in conjunction with the DSM Collaborative:

- Residential Smart $aver®
- Residential Energy Assessments Program
- Energy Efficiency Education Program for Schools Program
- Low Income Services Program
- Residential Direct Load Control - Power Manager Program
- Smart $aver® Prescriptive Program
- Smart $aver® Custom Program
- Peak Load Manager (Rider PLM) - PowerShare® Program
- Appliance Recycling Program
- Low Income Neighborhood Program
- My Home Energy Report Program

### 2. COST-EFFECTIVENESS OF PROGRAMS

All DSM programs are screened for cost-effectiveness using DSMore, a financial analysis tool designed to evaluate costs, benefits and risk. DSMore estimates a program's value at an hourly level across distributions of weather and/or energy costs or prices. By examining performance and cost effectiveness over a wide variety of weather and cost conditions, risks and benefits are evaluated in the same way as are traditional generation capacity additions, which ensures that demand-side resources are compared to supply-side resources on a comparable basis.

The analysis of DSM 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 either the DR or EE category of DSM programs.

- The UCT compares utility benefits (avoided energy and capacity related costs) to utility costs incurred to implement the program such as marketing,

[5] 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).

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 DSM 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 programs and indicate the likelihood that customers will participate. 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 Name | UCT | TRC | RIM | Participant |
|---|---|---|---|---|
| | 2012-2013 | | | |
| Appliance Recycling Program | 4.57 | 4.97 | 1.45 | |
| Energy Efficiency Education Program for Schools | 0.28 | 0.32 | 0.24 | |
| Low Income Neighborhood | 0.94 | 1.04 | 0.65 | |
| Low Income Services | 0.60 | 0.73 | 0.46 | |
| My Home Energy Report | 1.26 | 1.26 | 0.74 | |
| Residential Energy Assessments | 1.23 | 1.34 | 0.90 | |
| Residential Smart $aver® | 5.79 | 14.45 | 1.31 | 26.89 |
| Power Manager | 5.22 | 6.25 | 5.22 | |
| | | | | |
| Smart $aver® Custom | 5.92 | 2.20 | 1.36 | 2.53 |
| Smart $aver® Prescriptive - Energy Star Food Service Products | 1.12 | 0.87 | 0.66 | 3.13 |
| Smart $aver® Prescriptive - HVAC | 3.10 | 1.05 | 1.29 | 1.01 |
| Smart $aver® Prescriptive - Lighting | 8.03 | 2.51 | 1.69 | 2.22 |
| Smart $aver® Prescriptive - Motors/Pumps/VFD | 8.04 | 4.15 | 1.64 | 4.04 |
| Smart $aver® Prescriptive - Process Equipment | 4.87 | 5.09 | 1.61 | 5.88 |
| Power Share® | 4.89 | 22.26 | 4.89 | |

## 3. CURRENT DSM PROGRAMS

### Residential Smart $aver® Program

The Residential Smart $aver Program is offered under two separate tariffs, Residential Smart $aver® Energy Efficient Residences and Residential Smart $aver® Energy Efficient Products.

The Residential Smart $aver® Energy Efficient Residences program offers customers a variety of energy conservation measures designed to increase EE in their homes. The Program utilizes a network of contractors to encourage the installation of high efficiency equipment and the implementation of energy efficient home improvements. There are equipment and services incentives for:

- Installating high efficiency air conditioning (AC) and heat pump (HP) systems
- Performance of AC and HP tune-up maintenance services
- Implementation of attic insulation and air sealing services
- Implementation of duct sealing services

The Residential Smart $aver® Program received approval in the Commission's June 7, 2011 Order in Case No. 2010-00445. Duke Energy Kentucky launched the Residential Smart $aver® Program on August 15, 2011 but only offered incentives for the installation of the high efficiency AC and HP systems due to an ongoing vendor selection process. Once the vendor selection process and subsequent transition were completed in April 2012, the remaining incentives for the additional products and services were offered to residential Kentucky customers. Duct insulation received Commission approval June 29, 2012 and was subsequently added to the program.

Duke Energy Kentucky currently contracts with GoodCents to administer this program. GoodCents provides services including application processing, trade ally network management, data reporting, and IT support for program tools such as the trade ally portal which allows trade allies to register, check customer eligibility, and submit applications online. These Residential Smart $aver® services are jointly implemented with the Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Carolinas territories to reduce administrative costs and leverage promotion. GoodCents has experience delivering similar programs and uses an office in the Midwest to support Duke Energy programs in this region.

The Residential Smart $aver® Energy Efficient Products program provides high efficiency lighting through various channels. The Compact Fluorescent Lamps (CFLs) program offers customers CFLs for high-use fixtures. The CFL offer is available through an on-demand ordering platform, enabling customers to request CFLs and have them shipped directly to their homes. Customers have the flexibility to order and track their shipments by telephone, Duke Energy web site, and Online Services (OLS). Customers may call a toll free number to access the IVR (Interactive Voice Response) system which provides prompts to facilitate the ordering process. Both English and Spanish speaking customers may easily validate their account, determine their eligibility and place their order. Duke Energy web site users have access to Eligibility rules and frequently asked questions and can complete their order process online. Customers who participate in the Online Services program are encouraged to order through the Duke Energy web site, if they are eligible. New customer registrations and eligible customers may be intercepted upon logging in to make them aware of the program. The benefits of providing these three distinct channels include an improved customer experience, advanced inventory management, simplified program coordination, enhanced reporting, increased program participation, and reduced program costs.

The Residential Smart $aver® lighting program recently launched an online Saving Store for specialty lighting on April 26, 2013. The Savings Store is an extension of the on-demand ordering platform enabling eligible customers to purchase specialty bulbs and have them shipped directly to their homes. The program offers a variety of CFLs and LEDs including: Reflectors, Globes, Candelabra, 3 ways, Dimmables and A-line type bulbs. The incentive levels vary by bulb type and the customer pays the difference, including shipping. The maximum number of discounted bulbs available for each household varies by category, but customers may choose to order more bulbs without the Duke Energy Kentucky incentive. Customers can check eligibility and shop for specialty bulbs through the Company web site and OLS. The Savings Store is managed by a third party vendor, Energy Federation Inc. (EFI). EFI is responsible for maintaining the Savings Store and fulfilling all customer purchases. The Saving Store landing page provides information about the store, lighting products, account information and order history. Support features include a toll free number, live chat, package tracking, frequently asked questions, and an interactive educational tool providing information on bulb types, application types, savings, lighting benefits, understanding watts versus lumens, and recycling/safety.

The Property Manager Program is an extension of the Residential Smart $aver® lighting program and allows Duke Energy Kentucky to utilize an alternative delivery channel which targets multi-family apartment complexes. The program helps property managers upgrade lighting with 13 watt CFLs, reducing maintenance costs while improving tenant satisfaction by lowering energy bills. Each apartment may qualify for up to 12 CFLs per unit and the bulbs are installed in permanent fixtures during routine maintenance visits. The program tracks and reports the location and number of bulbs installed in each unit. Program information and supporting documents are available on the Duke Energy web site for property managers to learn more about the program and request applications to participate.

Duke Energy Kentucky proposed new measures to the Residential Smart $aver® program, which were approved by the Collaborative, and are the same measures included in Case No. 2013-00313 and approved for inclusion on December 19, 2013.

**Residential Energy Assessments Program**

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 over 30 years. WECC's knowledge of home energy audits comes from years of experience administering weatherization programs for income eligible customers. The programs are implemented through subcontractor Thermo-Scan Inspections (TSI), located in Carmel, Indiana. TSI has been in the business of providing a wide array of inspection services for 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 1980. 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 Building Performance Institute (BPI) Building Analyst certified 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, and examines insulation levels in different areas of the home, and checks appliances and heating/cooling systems. The auditors carry laptop computers on-site and enter the data collected into the software directly. This eliminates the likelihood of error from third party interpretation, and also allowing a customer to view their energy audit information immediately. 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, kitchen faucet aerator, bathroom aerator, outlet gaskets, and two 13 watt compact fluorescent bulbs, and one 18 watt compact fluorescent bulb. The auditors will offer to install these measures, if approved by the customer, so the customer can begin savings immediately on their electric bill, and to help insure proper installation and use.

For the period of July 1, 2012 through June 30, 2013, a total of 504 audits were completed in Kentucky. During this filing period, electronic mail and direct mail brochures were mailed to customers in an effort to acquire the proposed participation for this program process.

**Energy Efficiency Education Program for Schools**

In 2013, the Energy Education Program for Schools began offering an in depth classroom curriculum through the National Energy Education Development (NEED) project and a live theatrical production by The National Theatre for Children (NTC).

The NEED Project is designed to teach energy concepts of force, motion, light, sound, heat, electricity, magnetism, energy transformations, and EE. Energy curriculum, based upon State standards, and hands-on kits, provided to teachers for use in their classrooms, emphasize science inquiry and application of energy knowledge. 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, provide outreach to families and conduct energy education programs that assist families in implementing behavioral changes that reduce energy consumption. Teachers can utilize the kits and curriculum over many years. In addition, Duke Energy Home Energy Efficiency Kits are delivered to the classrooms to teach students and families to install EE measures and record energy savings.

The Kentucky NEED Project has been active in the Commonwealth's schools for 17 years. 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 EE 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. To support, recognize and encourage student energy leadership, Kentucky NEED hosts the annual Kentucky NEED Youth Awards for Energy Achievement in Washington, D.C., honoring teams of students who have successfully planned and facilitated energy projects in their schools and communities. In the Fall of 2012, NEED held two teacher workshops with 41 schools and 74 teachers participating in the training. The workshops exceeded the internal target of training 60 teachers for the school year.

To document the energy savings associated with the program, a home survey is provided for use in the classroom and with the Saving Energy at Home and School Kit, which serves as a companion to the Home Energy Efficiency Kits delivered to families in the Duke Energy Kentucky service area. Data collected from the home survey is collected and provided to Duke Energy annually. The data shows 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 2012-13 school year, 143 kits were distributed to Duke Energy qualified customers.

The live theatrical production category is presented by the NTC and is designed to educate students about EE via the theatrical production and participating students are eligible to receive a home EE starter kit that will be sent to the students' homes. This is the same kit offered through NEED. The program provides principals and teachers with innovative curricula that educate students about energy, electricity, ways energy is wasted and how to use resources wisely. Education materials focus on concepts such as energy, renewable fuels, and energy conservation through classroom and take home assignments, enhanced with a live 25 minute theatrical production by two professional actors. NTC performances target students in grades K-8. Cash prizes were awarded for the 2012-2013 school year to schools with the highest participation and 2 winners from Kentucky were selected and awarded prizes in July 2012. During spring 2013, NTC performed at 22 schools and delivered 630 kits to Duke Energy qualified customers.

**Low Income Services Program - Weatherization**

The Weatherization program portion of Low Income Services helps the Company's income-qualified customers reduce their energy consumption and lower their energy cost. This program specifically focuses on Low Income Home Energy Assistance Program (LIHEAP) customers that meet the income qualification level (*i.e.*, income below 150% of the federal poverty level). This program uses the LIHEAP intake process as well as other community outreach initiatives 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 energy costs. The program has provided weatherization services to the following number of customers:

| Fiscal Year | Customers Served |
|---|---|
| 1999 - 2000 | 251 |
| 2000 - 2001 | 283 |
| 2001 - 2002 | 203 |
| 2002 - 2003 | 252 |
| 2003 - 2004 | 252 |
| 2004 - 2005 | 130 |
| 2005 - 2006 | 232 |
| 2006 - 2007 | 252 |
| 2007 - 2008 | 265 |
| 2008 - 2009 | 222 |
| 2009 - 2010 | 199 |
| 2010 - 2011 | 234 |
| 2011 - 2012 | 220 |
| 2012 - 2013 | 228 |

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. Each home is placed into one of two "Tiers." The tiering process allows the agencies to be cost effective while spending the limited budgets where there is the most significant potential for savings. 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 tier structure is defined as follows:

| | **Therm / square foot** | **kWh use/ square foot** | **Investment Allowed** |
|---|---|---|---|
| Tier 1 | < 1 therm / ft2 | < 7 kWh / ft2 | Up to $600 |
| Tier 2 | >1 therm / 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). Tier One services include:

- Furnace Tune-up & Cleaning
- Furnace replacement if investment in repair over $500
- Venting check & repair
- Water Heater Wrap
- Pipe Wrap
- 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 $150
- Energy Education

**Tier Two Services**

Duke Energy Kentucky provides Tier Two services to customers using 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 2 services include all 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 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.

### Refrigerator Replacement

Refrigerator replacement is also a component of this program. 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. Replacing with a new Energy Star qualified refrigerator, with an estimated annual usage of 400 kWh, results in an overall savings to the average customer typically in excess of 1,000 kWh per year. Refrigerators tested and replaced:

| Year | Refrigerators Tested | Refrigerators Replaced |
|---|---|---|
| 2002 – 2003 | 116 | 47 |
| 2003 – 2004 | 163 | 73 |
| 2004 – 2005 | 115 | 39 |
| 2005 – 2006 | 116 | 52 |
| 2006 – 2007 | 136 | 72 |
| 2007 – 2008 | 173 | 85 |
| 2008 – 2009 | 153 | 66 |
| 2009 – 2010 | 167 | 92 |
| 2010 – 2011 | 112 | 76 |
| 2011 – 2012 | 107 | 64 |
| 2012 – 2013 | 206 | 69 |

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.

**Payment Plus**

The Payment Plus program impacts participants' behavior (*e.g.*, encourages utility bill payment and reducing arrearages) and results in energy conservation. The program includes continuing and new participants each year and consists of:

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 – to increase EE in customers' homes, participants must 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 for participating in the Residential Conservation and Energy Education program (weatherization services). If all of the requirements are completed, a household could receive up to a total of $500. This allows for approximately 200 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. Customers are tracked and the energy savings are evaluated to determine energy consumption and whether bill paying trends. 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.

Duke Energy Kentucky utilizes community action agencies to recruit customers to participate in the Payment Plus program. Using a list of potential customers provided by Duke Energy Kentucky, the agency removes any customer who has participated in the program in years past and sends a letter describing the program to the remaining customers. Included in this letter are various dates, times, and locations of scheduled classes. The courses are designed to accommodate customers' schedules and locations. The customer is asked to contact the agency to register for a course. Make-up courses are also offered to those customers who missed their scheduled time.

For the filing period beginning in the Fall of 2012, 108 participants attended energy education counseling, 102 participants attended budget counseling and 29 participant homes have been weatherized. There were 109 unique participants.

**Residential Direct Load Control - Power Manager Program**

The Power Manager program reduces demand by controlling residential air conditioning usage during periods of peak demand, high wholesale price conditions and/or generation emergency conditions during 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 under appropriate conditions.

Customers participating in this program receive a one-time enrollment incentive and a bill credit for each Power Manager event. Customers, who select to have their air conditioner cycled to achieve a 1 kW reduction in load, receive a $25 credit at installation. Customers selecting to have their air conditioner cycled to achieve a 1.5 kW load reduction, receive a $35 credit at installation. For both options, an incentive credit is applied to participants' bills for each cycling event. The credit varies based on marginal costs and the length of each event. Participants receive a minimum seasonal total of $5 or $8 in event incentives (for the 1.0 kW or 1.5 kW load reduction respectively). A settle-up credit for the balance of actual event credits to the seasonal minimum is applied following the end of the event season, if warranted.

Duke Energy Kentucky continues to use load control devices manufactured by Cooper Power Systems for new installations and replacement of existing load control devices. 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.

During the past fiscal year, the Company continued the replacement of older Power Manager devices that began in February 2011. In addition to improved operability and load reduction impacts, this replacement effort contributes to Kentucky program cost savings by reducing the expense allocation associated with the systems and hardware for the older device type.

Through June 30, 2013, nearly 6,000 new devices had been installed since the inception of the replacement project; less than 90 of the older devices remained. These devices are located in inaccessible areas of customers' property and require arrangements to complete the replacement. In late April 2013, Duke Energy Kentucky mailed notification letters to 303 remaining customers informing them that if the Company was unable to replace their Power Manager device, they would be removed from the program. Customers were asked to respond by May 13. In June, a postcard was mailed to the 87 customers who did not respond to the first mailing. (Although outside the timeframe of the 2012/13 fiscal year, a final notice postcard was mailed in July and those that did not respond had their Power Manager devices remotely deactivated in August.)

The Company continued limited promotion of Power Manager during the past fiscal year. An email solicitation was sent to customers who had opted to receive communications from the Company. There were 31 new Power Manager installations in the past fiscal year. In June, plans were being finalized for an outbound telemarketing campaign to Kentucky customers to begin in July.

There were a total of 8,956 air conditioners on the program as of the end of June, 2013; a net decline of 275 during the fiscal year. Despite improved operability driven by the replacement project, overall load reduction decreased by 0.2 MW (after losses) during this period.

Ongoing measurement and verification (M&V) is conducted through a sample of Power Manager customers with devices that record hourly run-time of the air conditioner unit and with load research interval meters that measure the household kWh usage. Operability studies are also used to measure the performance of Power Manager load control devices in Kentucky. In addition, Duke Energy Kentucky has reviewed the statistical sampling requirements of PJM for DR resources of this type. The Duke Energy Kentucky studies comply with all PJM requirements.

There were five Power Manager economic cycling events from June 1, 2013 through September 30, 2013. In addition, on August 28, 2013, there was a Power Manager test in conjunction with the PJM. The unseasonably cool weather through June in the Summer of 2013 resulted in no Power Manager events for that month.

| 2013 Power Manager Events | |
|---|---|
| **Date** | **Time (HE/EDT)** |
| 7/15/2013 | 1600-1700 |
| 7/16/2013 | 1600-1800 |
| 7/17/2013 | 1600-1700 |
| 7/18/2013 | 1700-1800 |
| 8/28/2013 * | 1600 |
| 9/10/2013 | 1700-1800 |

* PJM Test

**Smart $aver® Prescriptive Program**

The Smart $aver® Non-residential Prescriptive Incentive Program provides incentives to commercial and industrial consumers for installation of high efficiency equipment in applications involving new construction, retrofit, and replacement of failed equipment. The program also uses incentives to encourage maintenance of existing equipment in order to reduce energy usage. Incentives are provided based on Duke Energy Kentucky's cost effectiveness modeling to assure cost effectiveness over the life of the measure. This program offers incentives for:

- Lighting
- HVAC
- Pumps/Motors/Variable Frequency Drives
- Energy Star Food Service Products
- Information Technology Process Equipment and Water Conservation

Commercial and industrial consumers can have significant energy consumption, but may lack knowledge and understanding of the benefits of high efficiency alternatives. Duke Energy Kentucky's program provides financial incentives to customers to reduce the cost of high efficiency equipment, allowing customers to realize a quicker return on investment. The savings on utility bills allows customers to reinvest in their business. The Smart $aver® program also increases market demand for high efficiency equipment, which encourages dealers and distributors to stock such equipment.

The program promotes prescriptive incentives for the following technologies – lighting, HVAC, pumps, variable frequency drives, food services and process equipment. Starting in January 2014, Duke Energy added IT measures to the portfolio as well as additional measures in the lighting, HVAC, food service, and process equipment categories. These measures were approved by the Collaborative and are the same measures included in the August 15, 2013 Application filed in Case Number 2013-00313. Equipment and incentives are predefined based on current market assumptions and Duke Energy's engineering analysis. The eligible measures, incentives and requirements for both equipment and customer eligibility are listed in the applications posted on Duke Energy's Business and Large Business websites for each technology type.

Prior to 2013, Duke Energy contracted with WECC to handle the fulfillment responsibilities of the program and to provide training and technical support to our Trade Ally (TA) network. Also, CustomerLink provided call center services to customers who call the program's toll free number. Beginning January 2013, Ecova began providing these services for the program.

Getting the Trade Allies (TA) to support the program has proven to be the most effective way to promote the program to our business customers. At program rollout, Duke Energy and the WECC TA team took an aggressive approach to contacting trade allies associated with the technologies in and around Duke Energy's service territory. Existing relationships continued to be cultivated during 2012 while recruitment of new TAs also remained a focus. TA company names and contact information appears on the TA search tool located on the Smart $aver® website. This tool was designed to help customers who do not already work with a TA, to find someone in their location who can serve their needs. The Company continues to look for ways to engage the trade allies in promotion of the Program as well as more effective targeting of trade allies based on market opportunities.

During a focus group of lighting and mechanical trade allies conducted in December 2011, a suggestion was provided to develop an on-line application submission and status verification system. An on-line application and status verification platform is under development with Ecova. The launch was postponed until first quarter 2014, as development continues.

The Company recently completed an automated marketing campaign focused on lighting through the use of emailed newsletters and post cards. The marketing campaign was designed to generate leads based on activity taken by the email recipients to the content received. Personalized follow-up is underway based on the leads generated. A second automated campaign is underway for 2013 focused on HVAC.

An Energy Efficiency Store has launched on the Duke Energy website. The site provides customers the opportunity to take advantage of a limited number of incentive measures by purchasing qualified products from an on-line store and receiving an instant incentive that reduces the purchase price of the product. The incentives offered in the store will be consistent with current program incentive levels.

As the program has matured, much of the low-hanging fruit is already gathered. In response to this, Duke Energy continues to add measures to the Prescriptive portfolio in order to offer customers additional options for energy savings. Duke Energy also continues to reach those customers who have not yet participated in the Smart $aver® program.

The Company continues to work with outside consultants and internal resources to develop strategies to understand equipment supply/value chains and increase awareness of these measures going forward. Additionally, evaluations of alternative HVAC incentive designs geared to drive early equipment replacements continue.

Measures added to the program beginning January 1, 2014 include faucet aerators, showerheads, dishwashers, IT measures, ductless mini-split AC/HP units, cool roofs, demand control ventilation, additional LED measures, and additional variable speed drive air compressors. The complete list of measures can be found in Case No. 2013-00313. In this proceeding, the Company received approval to move the Thermal Storage measure from the Smart $aver® Prescriptive program to the Smart $aver® Custom program. The Company continues to evaluate the continuation of measures as their viability is impacted by Code and Standard changes.

Nonresidential customers are informed of programs via targeted marketing material and communications. Information about incentives is also distributed to trade allies, who in turn sell equipment and services to all sizes of nonresidential customers. Large business or assigned accounts are targeted primarily through assigned Duke Energy Kentucky account managers. Accounts that do not have an assigned account manager receive information about the program through direct mail, electronic mail and other direct marketing efforts including outbound call campaigns.

The internal marketing channel is comprised of assigned Large Business Account Managers, Segment Managers, and Local Government and Community Relations, who all identify potential opportunities as well as distribute program collateral and informational material to customers and TAs. In addition, the Economic and Business Development groups also provide a channel to customers who are new to the service territory.

In January 2013, an additional outreach resource was added to the Ohio/Kentucky/Indiana area to perform outreach to unassigned small and medium business customers. This new outreach representative provided to Duke Energy by Ecova follows up on customer leads to assist with program questions and steer customers to the TA search tool who are not already working with a TA. Duke Energy believes that this type of engagement will increase participation with small and medium business customers.

**Smart $aver® Custom Program**

This program encourages the installation of high efficiency equipment in new and existing nonresidential establishments with incentive payments to offset a portion of the higher cost of energy efficient equipment. Duke Energy Kentucky contracts with Ecova to provide the back office support for program implementation. This program is jointly implemented with the Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Carolinas territories to reduce administrative costs and leverage promotion. During the current reporting period of July 2012 through June 2013, the Kentucky Smart $aver® Custom Incentive program provided incentives totaling $75,690 to approximately 13 customers.

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™ [6] 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 EE. 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 into the Prescriptive Incentives makes planning and applying for measure incentives easier for customers.

In Case No. 2011-00471, a pilot was approved to expand the program to include all non-residential customers in the Company's electric service area taking service under all non-residential rates, except rate TT, who choose to participate by completing and submitting an application before initiating an EE project. In Case No. 2012-00085, the program was approved to begin July 1, 2012, superseding the pilot. Several custom applications completed in July 2012 through June 2013 originated with Duke Energy Kentucky's pilot expansion program.

No major changes are planned for the Custom Incentives program. However, Duke Energy Kentucky has tested the concept of calculation assistance in other states and will utilize the concept in Kentucky, should an appropriate opportunity present itself. Calculation assistance involves providing engineering resources to perform EE calculations for Custom projects of sufficient value and complexity but for which the customer's staff and/or vendors do not have the required expertise. The cost of calculation assistance is deducted from the customer's incentive payment so that the Company and other ratepayers do not bear the burden of additional cost.

In conjunction with Smart $aver Custom Program, the Company also offers an

[6] DSMore™ is a financial analysis tool designed to evaluate the costs, benefits, and risks of DSM programs and measures.

Energy Assessments Program. The purpose of this program is to assist customers with the evaluation of energy usage within a specific building(s) and to provide recommendations for energy savings projects. The program may provide a 50% subsidy for an EE audit completed in partnership with a contracted professional engineering organization. This program is jointly implemented within the Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Carolinas territories to reduce administrative costs and leverage resources.

Assessments are offered in three categories: Standard, SmartBuilding Advantage, and Segment Specific. Standard assessments mirror American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE) Level II energy audit criteria by providing general building assessments that consider all aspects of energy usage. SmartBuilding Advantage assessments are tailored toward large commercial office space. Two types of assessments are offered including Initial and Investment Grade. Initial resembles an ASHRAE Level II while Investment Grade is similar to an ASHRAE Level III which includes energy modeling. The last variety of assessment are termed Segment Specific. These assessments focus on targeted business markets or business processes. Examples include critical facilities assessments (data centers, labs, and hospitals), compressed air assessments, and chilled water assessments.

There are two main customer deliverables for all audits. The first is an Energy Report complete with details on how energy is being used and how efficiently the energy infrastructure operates. Additionally, the report provides Energy Conservation Measures (ECM) that recommend specific projects that can save energy. Each ECM includes estimated energy savings, estimated cost to implement, and estimated payback period. The second deliverable provided by the assessment is the data collected can be utilized to support a Smart $aver® Prescriptive or Custom Incentive Application.

During the current reporting period, July 2012 to June 2013, there has been no participation in the program. The costs and impacts associated with this program are included in the Custom program.

**Peak Load Manager (Rider PLM) - PowerShare® Program**

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). 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. 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® - CallOption® and QuoteOption®:

- CallOption®
    - A customer served under a CallOption® product agrees to reduce its demand upon notification by the Company.
    - Each time the Company exercises its option, the Company provides 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 PowerShare® Agreements, e.g., during PJM-declared emergency events.

- In addition to the energy credit, customers on the CallOption® receive an option premium credit.
- For the 2012/13 and 2013/14 PowerShare® programs associated with the fiscal year of this filing, there were three different enrollment choices for customers to select among. All three choices require curtailment availability for up to ten emergency events per PJM requirements for capacity participation. Economic events vary among the choices. Customers can select exposures of zero, five, or ten economic events.
- Customers must provide a minimum of 100 kW load response to 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 decides whether to reduce demand during the event period. If they do, the customer notifies the Company and provides an estimate of the customer's projected load reduction.
  - Each time the Company exercises the option, the Company provides an energy credit.
  - There is no option premium for the QuoteOption® product since customer load reductions are voluntary.
  - Customers must provide a minimum of 100 kW load response to qualify for QuoteOption®.

**PowerShare® 2013 Summary**

Duke Energy Kentucky's customer participation goal for 2013 was to retain all customers that currently participate and to promote customer migration to the CallOption® program. Customer activity is shown in the table below:

| Table C-2: Kentucky PowerShare® Participation Update | | | | |
|---|---|---|---|---|
| Month | CallOption | | QuoteOption | |
| | Enrolled Customers* | Summer Capability** | Enrolled Customers* | Summer Capability** |
| Jan-13 | 19 | 24.6 | 0 | 0 |
| Feb-13 | 19 | 24.6 | 0 | 0 |
| Mar-13 | 19 | 24.6 | 0 | 0 |
| Apr-13 | 19 | 24.6 | 0 | 0 |
| May-13 | 19 | 24.6 | 0 | 0 |
| Jun-13 | 20 | 23.0 | 0 | 0 |
| Jul-13 | 20 | 23.0 | 0 | 0 |
| Aug-13 | 20 | 23.0 | 0 | 0 |
| Sep-13 | 20 | 23.0 | 0 | 0 |
| Oct-13 | 20 | 23.0 | 0 | 0 |
| Nov-13 | 20 | 23.0 | 0 | 0 |
| Dec-13 | 20 | 23.0 | 0 | 0 |

*Enrolled Customers represents the number of parent accounts participating. Also note values do not include participant who was removed in September.

**Summer Capability is consistent with the associated program year. Numbers reported are adjusted for losses.

During 2013 there were four economic CallOption® events and no QuoteOption® events. There were also two PJM tests. There were no CallOption® emergency events. The table below summarizes event participation.[7]

[7] "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 in the table, 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."

**Table C-3**

| **Duke Energy Kentucky - PowerShare CallOption Economic Tests & Emergency Events**<br>2013 Activity | | | | | | |
|---|---|---|---|---|---|---|
| Date | Event Hours (EDT) | Event Participants | Participants Reducing Load Partially or Fully | Average Hourly Load Reduction Expected - At the Meter (MW) | Average Hourly Load Reduction - At the Meter (MW) | Average Hourly Load Reduction - At the Plant (MW) |
| 7/16/2013 | 1300-1900 | 18 | 8 | 23.7 | 5.3 | 5.5 |
| 7/17/2013 | 1300-1900 | 18 | 3 | 24.3 | 5.5 | 5.7 |
| 7/19/2013 | 1300-1900 | 18 | 7 | 23.3 | 4.5 | 4.7 |
| 8/28/2013* | 1500-1600 | 20 | 19 | 25.4 | 28.2 | 29.6 |
| 9/11/2013 | 1300-1900 | 18 | 7 | 25.3 | 4.0 | 4.2 |
| 9/24/2013# | 1600-1700 | 2 | 2 | 1.1 | 1.7 | 1.8 |

* PJM Test Event
# PJM Re-test Event

**Appliance Recycling Program**

The Appliance Recycling program encourages customers to responsibly dispose of older, functioning but inefficient refrigerators and freezers. These are typically second or third units in the home. Customers will have the old unit picked up at their home at no charge and will receive an incentive for participating. Disposed units will have 95 percent of material recycled with only 5 percent entering landfills. Program marketing consists of direct mail, social media, and community presentations and publications like newsletters. Point of sale messaging will also be pursued with prominent appliance retailers.

| ARP **Participants** | **July-December 2012** | **January–June 2013** | **Total** |
|---|---|---|---|
| Refrigerator | 91 | 318 | 409 |
| Freezer | 32 | 85 | 117 |

**Low Income Neighborhood Program**

The Duke Energy Kentucky Neighborhood Program takes a non-traditional approach to serving income-qualified areas of the Duke Energy Kentucky service territory. The program engages targeted customers with personal interaction in a familiar setting while ultimately reducing energy consumption by directly installing measures and educating the customer on better ways to manage their energy bills. Examples of direct installed measures include CFLs, water heater and pipe wrap, low flow shower heads/faucet aerators, window and door air sealing and HVAC filter replacements. Targeted low income neighborhoods qualify for the program if at least 50% of the households are at or below 200% of the federal poverty guidelines. Duke Energy Kentucky analyzes electric usage data and previous program participation to prioritize neighborhoods that have the greatest need and propensity to participate. While the goal is to serve neighborhoods where the majority of residents are lower income, the program is available to all Duke Energy Kentucky customers in the defined neighborhood. This program is available to both homeowners and renters occupying single family and multi-family dwellings in the target neighborhoods that have electric service provided by Duke Energy Kentucky.

A community-based kick-off event is held in targeted neighborhoods. The kick-off events feature local community leaders and energy experts that will explain program components. The purpose of the kick-off event is to rally the neighborhood around EE and to help customers understand steps needed to lower their energy bills. Following the kick-off event, energy assessments are completed in the customers' homes and the appropriate energy saving measures are installed if the customer elects to have the work completed. Direct mail and call center support supplement community based outreach. The program is a source of leads for other Duke Energy Kentucky and external EE programs.

Through the end of June 2013, we have completed more than 150 homes in Duke Energy Kentucky territory and continue to work in the area. The first kickoff was in Covington, Kentucky on March 28, 2013. Additionally, three tent events were held, partnering with local business to allow residents to gain information about the program. The Company has partnered with St. Elizabeth Medical Center and other community businesses to help promote and rally customers around our efforts. The Company is still performing work in the area. The program is slowly gaining momentum and there is an increased interest in participation.

**My Home Energy Report Program**

The My Home Energy Report compares household electric usage to similar, neighboring homes, and provides recommendations to lower energy consumption. The report also promotes the Company's other EE programs when applicable. These normative comparisons are intended to induce an energy consumption behavior change. The My Home Energy Report is delivered in printed or online form to targeted customers with desirable characteristics who are likely to respond to the information.

The printed reports are distributed up to 12 times per year; however delivery may be interrupted during the off-peak energy usage months in the fall and spring. Currently to qualify to receive the MyHER report, customers must be living in a single metered, single family home with 13 months usage history and are not on a budget billing customers. Kentucky customers started receiving reports in September 2012 and have received eight reports between September 2012 and June 2013.

The MyHER program is an opt out program and the Company provides information on every report as to how a customer request to stop receiving the reports. Since the program began in September 2012, only 74 customers out of roughly 44,000 KY customers participating in the program have chosen to opt out.

In August 2013, a revised MyHER report was introduced to customers. Previously the report showed customer comparisons in dollar amounts. The dollar amounts were derived using a customer's actual usage and a rate factor for each state. Unfortunately, this dollar amount did not always match the dollar amount on the customer's bill and was causing customer confusion. The August 2013 report showed customer comparison in kWh figures which are an exact match to the customer's bill. To date, only a few customers have reacted negatively to the change. Many customers requested the change. This change to kWh comparisons also allows the Company to open this program to customers on payment plans. These customers were not included previously because the dollar amount on their report would not match their bill amount. Now that the Company is only displaying kWh figures, these will now match payment plan customers' bills. The Company is also evaluating the possibility of providing the report to customers via on-line or through mobile channels.

**New Programs**

Duke Energy began offering the Energy Management Information and Services (EMIS) pilot program as part of the EE portfolio on May 5, 2014. EMIS is a pilot program for medium and large customers in the office space, college/university, K-12, retail and hospital segments. The offer is comprised of energy analytical software, an onsite energy assessment and periodic monitoring to encourage low cost EE measures in the buildings.

1) Forecasted Program Costs

**Total Costs for 2 Buildings**

| | |
|---|---|
| Product Costs | $48,864 |
| Admin. Costs | $5,429 |
| M&V Costs | $2,715 |
| **Total Costs** | **$57,008** |

2) Cost Effectiveness of the pilot:

| Building Use Type | UCT | TRC | RIM (Net Fuel) | Participant Cost Test |
|---|---|---|---|---|
| Office Space (1 building) | 2.20 | 1.19 | 1.05 | 1.66 |
| Retail (1 building) | 1.67 | 0.98 | 0.91 | 1.52 |

3) Further details will be included in the annual cost recovery filing to be filed by November 15, 2014.

For the purpose of this IRP, projected impacts and costs associated with this pilot and the expected commercialization have been included in the Expected Case EE analysis.

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

## Expected Case Energy Efficiency Program Costs

Section 8(3)(e)4
Energy Efficiency Program Costs

| Energy Efficiency Programs | Year 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | | | | | | | | | | | | | | | | |
| Appliance Recycling | [redacted] | | | | | | | | | | | | | | | |
| Energy Efficiency Education Program for Schools | | | | | | | | | | | | | | | | |
| Low Income Neighborhood | | | | | | | | | | | | | | | | |
| Low Income Services | | | | | | | | | | | | | | | | |
| My Home Energy Report | | | | | | | | | | | | | | | | |
| Residential Energy Assessments | | | | | | | | | | | | | | | | |
| Residential Smart $aver® | | | | | | | | | | | | | | | | |
| Power Manager | | | | | | | | | | | | | | | | |
| Total Residential | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | |
| Non-Residential | | | | | | | | | | | | | | | | |
| Energy Management Information and Services | | | | | | | | | | | | | | | | |
| Smart $aver® Custom (1) | | | | | | | | | | | | | | | | |
| Smart $aver® Prescriptive - Energy Star Food Service Products | | | | | | | | | | | | | | | | |
| Smart $aver® Prescriptive - HVAC | | | | | | | | | | | | | | | | |
| Smart $aver® Prescriptive - Lighting | | | | | | | | | | | | | | | | |
| Smart $aver® Prescriptive - Motors/Pumps/VFD | | | | | | | | | | | | | | | | |
| Smart $aver® Prescriptive - Process Equipment | | | | | | | | | | | | | | | | |
| Smart $aver® Prescriptive - IT | | | | | | | | | | | | | | | | |
| PowerShare® | | | | | | | | | | | | | | | | |
| Total Non-Residential | | | | | | | | | | | | | | | | |
| Total Costs | | | | | | | | | | | | | | | | |

(1) The costs for the Smart Saver® Energy Assessments are included in the Prescriptive and Custom Programs.

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

## Expected Case Energy Efficiency Avoided Cost

Section 8(3)e5
Energy Efficiency Avoided Costs

| Energy Efficiency Programs | Year 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | [redacted] | | | | | | | | | | | | | | | |
| Appliance Recycling | | | | | | | | | | | | | | | | |
| Energy Efficiency Education Program for Schools | | | | | | | | | | | | | | | | |
| Low Income Neighborhood | | | | | | | | | | | | | | | | |
| Low Income Services | | | | | | | | | | | | | | | | |
| My Home Energy Report | | | | | | | | | | | | | | | | |
| Residential Energy Assessments | | | | | | | | | | | | | | | | |
| Residential Smart $aver® | | | | | | | | | | | | | | | | |
| Power Manager | | | | | | | | | | | | | | | | |
| Total Residential | | | | | | | | | | | | | | | | |
| Non-Residential | | | | | | | | | | | | | | | | |
| Energy Management Information and Services | | | | | | | | | | | | | | | | |
| Smart $aver® Custom | | | | | | | | | | | | | | | | |
| Smart $aver® Prescriptive - Energy Star Food Service Products | | | | | | | | | | | | | | | | |
| Smart $aver® Prescriptive - HVAC | | | | | | | | | | | | | | | | |
| Smart $aver® Prescriptive - Lighting | | | | | | | | | | | | | | | | |
| Smart $aver® Prescriptive - Motors/Pumps/VFD | | | | | | | | | | | | | | | | |
| Smart $aver® Prescriptive - Process Equipment | | | | | | | | | | | | | | | | |
| Smart $aver® Prescriptive - IT | | | | | | | | | | | | | | | | |
| PowerShare® | | | | | | | | | | | | | | | | |
| Total Non-Residential | | | | | | | | | | | | | | | | |
| Total Costs | | | | | | | | | | | | | | | | |

DUKE ENERGY.

*Kentucky*

# The Duke Energy Kentucky 2014 Integrated Resource Plan

## July 1, 2014

## Appendix D – Recommended Plan

## APPENDIX D – RECOMMENDED PLAN
## Table of Contents

**Section** **Page**

**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.

igure 8.(3).(b)(12)a-c, e, g
Duke Energy Kentucky
Projected Cost and Operating Information For
**East Bend 2**

**Nominal Dollars**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Availability Factor % | | | | | | | | | | | | | | | | | | | | | |
| Average Heat Rate (BTU/kWh) | | | | | | | | | | | | | | | | | | | | | |
| Cost of Fuel ($/MBTU) | | | | | | | | | | | | | | | | | | | | | |
| Fixed O&M ($000) | | | | | | | | | | | | | | | | | | | | | |
| Variable O&M ($000) | | | | | | | | | | | | | | | | | | | | | |
| Avg. Variable Prod. Costs (cents/kWh) | | | | | | | | | | | | | | | | | | | | | |
| Total Prod. Costs (cents/kWh) | | | | | | | | | | | | | | | | | | | | | |

| | |
|---|---|
| | |
| Cost of Fuel ($/MBTU) | |
| Fixed O&M ($000) | |
| Variable O&M ($000) | |
| Avg. Variable Prod. Costs (cents/kWh) | |
| Total Prod. Costs (cents/kWh) | |

Figure 8.(3).(b)(12)a-c, e, g
Duke Energy Kentucky
Projected Cost and Operating Information For
**Miami Fort 6**

**Nominal Dollars**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Availability Factor % | | | | | | | | | | | | | | | | | | | | | |
| Average Heat Rate (BTU/kWh) | | | | | | | | | | | | | | | | | | | | | |
| Cost of Fuel ($/MBTU) | | | | | | | | | | | | | | | | | | | | | |
| Fixed O&M ($000) | | | | | | | | | | | | | | | | | | | | | |
| Variable O&M ($000) | | | | | | | | | | | | | | | | | | | | | |
| Avg. Variable Prod. Costs (cents/kWh) | | | | | | | | | | | | | | | | | | | | | |
| Total Prod. Costs (cents/kWh) | | | | | | | | | | | | | | | | | | | | | |

| | |
|---|---|
| | [redacted] |
| Cost of Fuel ($/MBTU) | |
| Fixed O&M ($000) | |
| Variable O&M ($000) | |
| Avg. Variable Prod. Costs (cents/kWh) | |
| Total Prod. Costs (cents/kWh) | |

Figure 8.(3).(b)(12)a-c, e, g
Duke Energy Kentucky
Projected Cost and Operating Information For
**Woodsdale 1**

**Nominal Dollars**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Availability Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Average Heat Rate (BTU/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Cost of Fuel ($/MBTU) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Fixed O&M ($000) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Variable O&M ($000) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Avg. Variable Prod. Costs (cents/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Total Prod. Costs (cents/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |

[redacted]

| | [redacted] |
|---|---|
| Cost of Fuel ($/MBTU) | [redacted] |
| Fixed O&M ($000) | [redacted] |
| Variable O&M ($000) | [redacted] |
| Avg. Variable Prod. Costs (cents/kWh) | [redacted] |
| Total Prod. Costs (cents/kWh) | [redacted] |

Figure 8.(3).(b)(12)a-c, e, g
Duke Energy Kentucky
Projected Cost and Operating Information For
**Woodsdale 2**

**Nominal Dollars**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Availability Factor % | | | | | | | | | | | | | | | | | | | | | |
| Average Heat Rate (BTU/kWh) | | | | | | | | | | | | | | | | | | | | | |
| Cost of Fuel ($/MBTU) | | | | | | | | | | | | | | | | | | | | | |
| Fixed O&M ($000) | | | | | | | | | | | | | | | | | | | | | |
| Variable O&M ($000) | | | | | | | | | | | | | | | | | | | | | |
| Avg. Variable Prod. Costs (cents/kWh) | | | | | | | | | | | | | | | | | | | | | |
| Total Prod. Costs (cents/kWh) | | | | | | | | | | | | | | | | | | | | | |

| | |
|---|---|
| Cost of Fuel ($/MBTU) | |
| Fixed O&M ($000) | |
| Variable O&M ($000) | |
| Avg. Variable Prod. Costs (cents/kWh) | |
| Total Prod. Costs (cents/kWh) | |

Figure 8.(3).(b)(12)a-c, e, g
Duke Energy Kentucky
Projected Cost and Operating Information For
**Woodsdale 3**

**Nominal Dollars**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Availability Factor % | | | | | | | | | | | | | | | | | | | | | |
| Average Heat Rate (BTU/kWh) | | | | | | | | | | | | | | | | | | | | | |
| Cost of Fuel ($/MBTU) | | | | | | | | | | | | | | | | | | | | | |
| Fixed O&M ($000) | | | | | | | | | | | | | | | | | | | | | |
| Variable O&M ($000) | | | | | | | | | | | | | | | | | | | | | |
| Avg. Variable Prod. Costs (cents/kWh) | | | | | | | | | | | | | | | | | | | | | |
| Total Prod. Costs (cents/kWh) | | | | | | | | | | | | | | | | | | | | | |

| | |
|---|---|
| Cost of Fuel ($/MBTU) | |
| Fixed O&M ($000) | |
| Variable O&M ($000) | |
| Avg. Variable Prod. Costs (cents/kWh) | |
| Total Prod. Costs (cents/kWh) | |

Figure 8.(3).(b)(12)a-c, e, g
Duke Energy Kentucky
Projected Cost and Operating Information For
**Woodsdale 4**

**Nominal Dollars**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Availability Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Average Heat Rate (BTU/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Cost of Fuel ($/MBTU) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Fixed O&M ($000) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Variable O&M ($000) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Avg. Variable Prod. Costs (cents/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Total Prod. Costs (cents/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |

[redacted]

| | [redacted] | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cost of Fuel ($/MBTU) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Fixed O&M ($000) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Variable O&M ($000) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Avg. Variable Prod. Costs (cents/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Total Prod. Costs (cents/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |

Figure 8.(3).(b)(12)a-c, e, g
Duke Energy Kentucky
Projected Cost and Operating Information For
**Woodsdale 5**

**Nominal Dollars**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Availability Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Average Heat Rate (BTU/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Cost of Fuel ($/MBTU) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Fixed O&M ($000) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Variable O&M ($000) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Avg. Variable Prod. Costs (cents/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Total Prod. Costs (cents/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |

[redacted]

| | |
|---|---|
| | [redacted] |
| Cost of Fuel ($/MBTU) | [redacted] |
| Fixed O&M ($000) | [redacted] |
| Variable O&M ($000) | [redacted] |
| Avg. Variable Prod. Costs (cents/kWh) | [redacted] |
| Total Prod. Costs (cents/kWh) | [redacted] |

Figure 8.(3).(b)(12)a-c, e, g
Duke Energy Kentucky
Projected Cost and Operating Information For
**Woodsdale 6**

**Nominal Dollars**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Availability Factor % | | | | | | | | | | | | | | | | | | | | | |
| Average Heat Rate (BTU/kWh) | | | | | | | | | | | | | | | | | | | | | |
| Cost of Fuel ($/MBTU) | | | | | | | | | | | | | | | | | | | | | |
| Fixed O&M ($000) | | | | | | | | | | | | | | | | | | | | | |
| Variable O&M ($000) | | | | | | | | | | | | | | | | | | | | | |
| Avg. Variable Prod. Costs (cents/kWh) | | | | | | | | | | | | | | | | | | | | | |
| Total Prod. Costs (cents/kWh) | | | | | | | | | | | | | | | | | | | | | |

| | |
|---|---|
| Cost of Fuel ($/MBTU) | |
| Fixed O&M ($000) | |
| Variable O&M ($000) | |
| Avg. Variable Prod. Costs (cents/kWh) | |
| Total Prod. Costs (cents/kWh) | |

Figure 8.(3).(b)(12)a-c, e, g
Duke Energy Kentucky
Projected Cost and Operating Information For
**Composite Coal Unit**

**Nominal Dollars**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Availability Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Average Heat Rate (BTU/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Cost of Fuel ($/MBTU) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Fixed O&M ($000) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Variable O&M ($000) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Avg. Variable Prod. Costs (cents/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Total Prod. Costs (cents/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |

[redacted]

| | |
|---|---|
| | [redacted] |
| Cost of Fuel ($/MBTU) | [redacted] |
| Fixed O&M ($000) | [redacted] |
| Variable O&M ($000) | [redacted] |
| Avg. Variable Prod. Costs (cents/kWh) | [redacted] |
| Total Prod. Costs (cents/kWh) | [redacted] |

Figure 8.(3).(b)(12)a-c, e, g
Duke Energy Kentucky
Projected Cost and Operating Information For
**New Biomass**

**Nominal Dollars**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Availability Factor % | | | | | | | | | | | | | | | | | | | | | |
| Average Heat Rate (BTU/kWh) | | | | | | | | | | | | | | | | | | | | | |
| Cost of Fuel ($/MBTU) | | | | | | | | | | | | | | | | | | | | | |
| Fixed O&M ($000) | | | | | | | | | | | | | | | | | | | | | |
| Variable O&M ($000) | | | | | | | | | | | | | | | | | | | | | |
| Avg. Variable Prod. Costs (cents/kWh) | | | | | | | | | | | | | | | | | | | | | |
| Total Prod. Costs (cents/kWh) | | | | | | | | | | | | | | | | | | | | | |

| | |
|---|---|
| | [redacted] |
| Cost of Fuel ($/MBTU) | |
| Fixed O&M ($000) | |
| Variable O&M ($000) | |
| Avg. Variable Prod. Costs (cents/kWh) | |
| Total Prod. Costs (cents/kWh) | |

Figure 8.(3).(b)(12)a-c, e, g
Duke Energy Kentucky
Projected Cost and Operating Information For
**New Solar**

**Nominal Dollars**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Availability Factor % | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Average Heat Rate (BTU/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Cost of Fuel ($/MBTU) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Fixed O&M ($000) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Variable O&M ($000) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Avg. Variable Prod. Costs (cents/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Total Prod. Costs (cents/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cost of Fuel ($/MBTU) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Fixed O&M ($000) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Variable O&M ($000) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Avg. Variable Prod. Costs (cents/kWh) | [redacted] | | | | | | | | | | | | | | | | | | | | |
| Total Prod. Costs (cents/kWh) | [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 Chapter 5, most of the specific technology parameters used in the screening process were based on information taken from several sources. B&M and EPRI consider its information to be proprietary and confidential trade secrets. Duke Energy considers its internal estimates to be confidential, 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

Duke Energy Kentucky
Capital Costs and Escalation Factors
New Units

| | Coal Purch - Composite Coal Unit 1 (195 MW) | Solar Unit 1 (8 MW) | Solar Unit 2 (8 MW) | Solar Unit 3 (8 MW) | Solar Unit 4 (8 MW) | Solar Unit 5 (8 MW) | Solar Unit 6 (8 MW) | Solar Unit 7 (8 MW) | Solar Unit 8 (8 MW) | Solar Unit 9 (8 MW) | Solar Unit 10 (8 MW) | Solar Unit 11 (8 MW) | Biomass Landfill Gas Unit 1 (2 MW) | Biomass Landfill Gas Unit 2 (2 MW) | Biomass Landfill Gas Unit 3 (2 MW) | Biomass Landfill Gas Unit 4 (2 MW) | Biomass Landfill Gas Unit 5 (2 MW) | Biomass Landfill Gas Unit 6 (2 MW) | Biomass Landfill Gas Unit 7 (2 MW) | Biomass Landfill Gas Unit 8 (2 MW) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capital Costs (Real 2014 $/kW) | [redacted] | | | | | | | | | | | | | | | | | | | |
| Capital Costs (Nominal $/kW) | [redacted] | | | | | | | | | | | | | | | | | | | |
| Total Capital Costs (Real 2014 $000) | [redacted] | | | | | | | | | | | | | | | | | | | |
| Total Capital Costs (Nominal $000) | [redacted] | | | | | | | | | | | | | | | | | | | |
| Capital Escalation Rate (%) | [redacted] | | | | | | | | | | | | | | | | | | | |
| Variable O&M Escalation Rate (%) | [redacted] | | | | | | | | | | | | | | | | | | | |
| Fixed O&M Escalation Rate (%) | [redacted] | | | | | | | | | | | | | | | | | | | |

**Section 9(1) Present Value Revenue Requirements**

The 2014 Present Value Revenue Requirement (PVRR) for the preferred 2014 Plan is $3,813 million. The effective after-tax discount rate used was 6.72%.

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.

**Section 9(3) Yearly Revenue Requirements**

The projections of yearly revenue requirements are shown on the following page, in redacted form.

## Section 9(3)
## Duke Energy Kentucky
## Annual Revenue Requirements – Real and Nominal

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Annual Revenue Requirement - Nominal (000's $) | 180,166 | 184,500 | 194,692 | 199,118 | 206,578 | 214,278 | 300,228 | 317,838 | 333,168 | 348,854 | 368,361 | 386,740 | 407,929 | 436,335 | 461,621 | 486,361 | 511,252 | 544,605 | 576,312 | 608,098 | 640,537 |
| Annual Revenue Requirement - Real (000's $) | 180,166 | 180,000 | 185,311 | 184,901 | 187,150 | 189,391 | 258,886 | 267,386 | 273,446 | 279,338 | 287,763 | 294,752 | 303,318 | 316,526 | 326,701 | 335,816 | 344,392 | 357,912 | 369,511 | 380,382 | 390,901 |

Notes: Nominal values were discounted to 2014 using a rate of 2.50%.

**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)

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 Energy Requirements | 4,480 | 4,514 | 4,588 | 4,631 | 4,672 | 4,714 | 4,702 | 4,709 | 4,734 | 4,761 | 4,796 | 4,820 | 4,856 | 4,899 | 4,952 | 4,990 | 5,032 | 5,080 | 5,139 | 5,187 | 5,241 |

| 2 Energy By Fuel Type | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 3,918 | 4,164 | 4,207 | 4,512 | 4,175 | 4,828 | 4,570 | 4,743 | 4,621 | 4,759 | 4,638 | 4,753 | 4,634 | 4,740 | 4,608 | 4,639 | 4,466 | 4,612 | 4,459 | 4,557 | 4,411 |
| Gas | 63 | 80 | 86 | 66 | 17 | 9 | 26 | 12 | 16 | 19 | 22 | 27 | 31 | 35 | 45 | 59 | 68 | 0 | 0 | 0 | 0 |
| Renewables | 0 | 0 | 0 | 0 | 0 | 28 | 55 | 83 | 111 | 135 | 148 | 175 | 190 | 218 | 246 | 246 | 246 | 245 | 247 | 246 | 258 |

| 3 Firm Purchases From Other Utilities | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| None | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | (7) | (23) | (39) | (56) | (73) | (91) | (109) | (127) | (144) | (162) | (180) | (197) | (215) | (233) | (250) | (268) | (286) | (304) | (321) | (339) | (339) |
| Total | (7) | (23) | (39) | (56) | (73) | (91) | (109) | (127) | (144) | (162) | (180) | (197) | (215) | (233) | (250) | (268) | (286) | (304) | (321) | (339) | (339) |

| Net (Sales)/Purchaes | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Market | 491 | 247 | 256 | (3) | 406 | (243) | (58) | (256) | (158) | (314) | (191) | (333) | (215) | (328) | (197) | (222) | (33) | (80) | 112 | 45 | 233 |

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

| Coal | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy (GWh) | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 | 3,918 |
| Total (000 Tons) | 1,756 | 1,903 | 1,931 | 2,068 | 1,905 | 2,207 | 2,091 | 2,171 | 2,114 | 2,177 | 2,121 | 2,175 | 2,120 | 2,169 | 2,109 | 2,124 | 2,045 | 2,113 | 2,044 | 2,089 | 2,021 |
| (000 MBTUs) Consumed | 40,965 | 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 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy (GWh) | 63 | 80 | 86 | 66 | 17 | 9 | 26 | 12 | 16 | 19 | 22 | 27 | 31 | 35 | 45 | 59 | 68 | 0 | 0 | 0 | 0 |
| Total (MCF) | 914 | 1,171 | 1,255 | 952 | 253 | 138 | 373 | 176 | 237 | 278 | 317 | 399 | 457 | 519 | 654 | 855 | 991 | 0 | 2 | 0 | 2 |
| (000 MBTUs) Consumed | 938 | 1,201 | 1,287 | 977 | 260 | 141 | 383 | 181 | 243 | 285 | 325 | 410 | 468 | 532 | 671 | 877 | 1,017 | 0 | 2 | 0 | 2 |

| Biomass | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy (GWh) | 0 | 0 | 0 | 0 | 0 | 15 | 31 | 46 | 62 | 62 | 62 | 77 | 93 | 108 | 124 | 124 | 123 | 123 | 124 | 124 | 124 |

| Wind and Solar | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy (GWh) | 0 | 0 | 0 | 0 | 0 | 12 | 24 | 37 | 49 | 73 | 86 | 98 | 98 | 110 | 122 | 122 | 122 | 122 | 122 | 122 | 134 |

DUKE ENERGY®

Kentucky

# The Duke Energy Kentucky 2014 Integrated Resource Plan

July 1, 2014

## Appendix E – Response to 2011 IRP Staff Comments

## APPENDIX E – SECTION 11(4) RESPONSE TO 2011 IRP STAFF COMMENTS

### Table of Contents

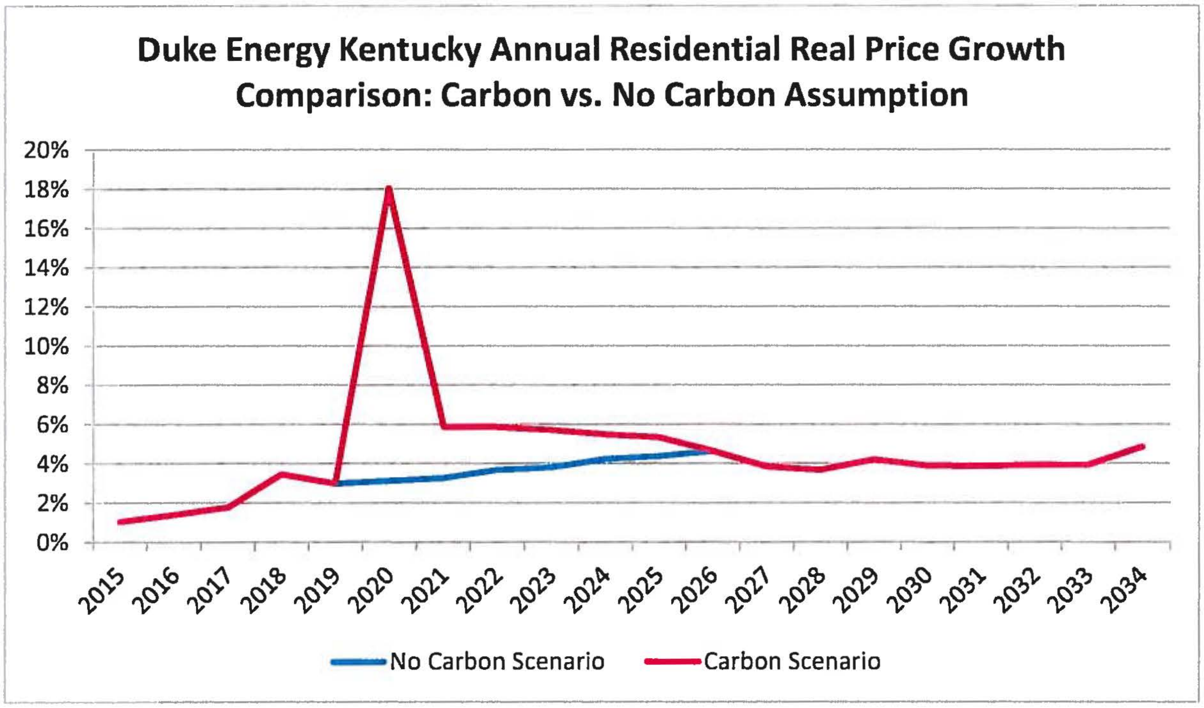
## 2011 IRP Commission Response #1, Load Forecasting

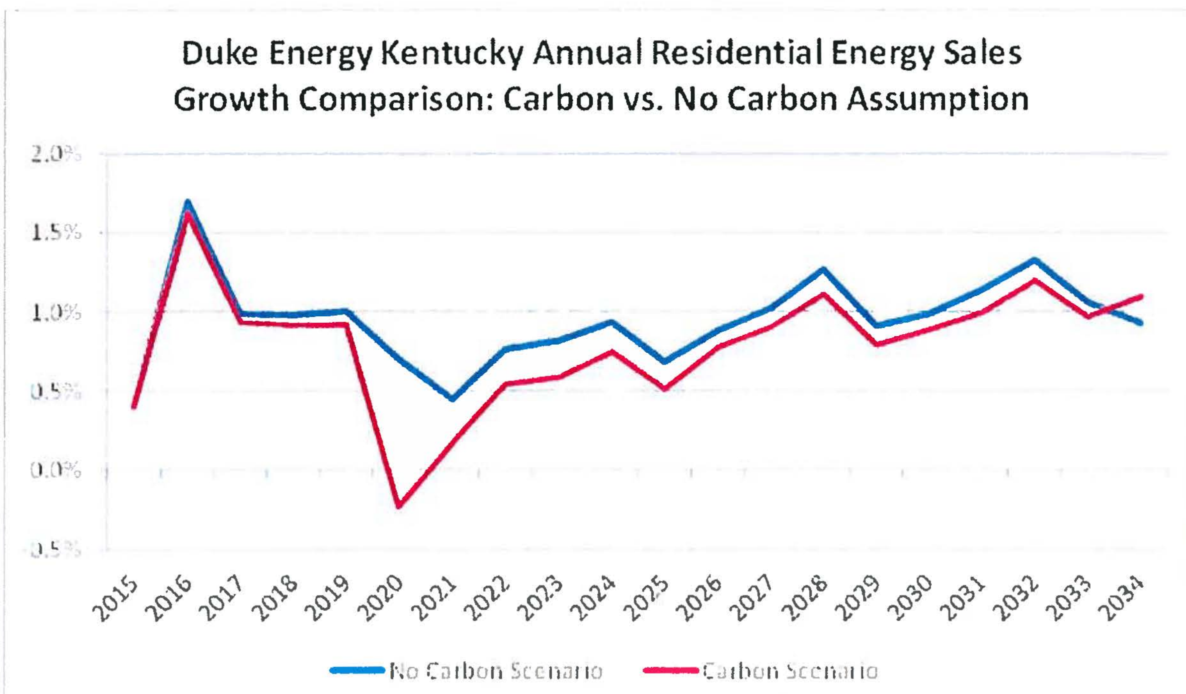
**Recommendation:** Implementing existing and future environmental regulations could have significant effects on fuel prices, electricity prices, income, employment and other economic variables. Service area economic activity adjusting to the effects of potentially stringent environmental regulations could significantly impact service area energy use and peak demand. Therefore, the effects of existing and/or pending environmental regulations of electricity prices and other economic variables should be explicitly examined as a part of the load forecast, including the sensitivity analysis.

Future increases in electricity prices due to stricter environmental regulations could be large enough to affect consumer behavior and energy consumption. A discussion of how price increases impact the elasticity of customer demand should be included in the next IRP.

**Response:** Existing and future environmental regulations will alter the projected generation mix, significantly reducing the role of coal-fired generation, while increasing the role of nuclear, natural gas, and non-hydropower renewable technologies. However, there is uncertainty as to whether nuclear and renewable energy can quickly and efficiently replace coal-fired generation.

To determine the impact on the current energy forecast, scenarios were run assuming realized future environmental regulation impacts ("carbon scenario"); and assuming current regulations and prices will not be impacted by expected future environmental regulations ("no carbon scenario"). Using the residential sector as an example, the chart below illustrates that future environmental regulations increases real prices significantly around 2019, as investment in new combined cycle, renewable, and nuclear capacity becomes more important than using natural gas and biomass to comply with future environmental regulations. These higher prices significantly reduce load growth starting in 2019, even before the impact of utility energy efficiency programs are considered. The carbon scenario slowly increases its annual growth after 2020, but does not reach the level of growth seen in the "no carbon" scenario until about 2033. The two charts below illustrate the difference between the two scenarios in relation to price and energy, and illustrate the negative implications these regulations would have on Duke Energy Kentucky's load growth.



**2011 IRP Commission Response #2, DSM**

**Recommendation:** While the Staff is generally pleased with the DSM efforts of Duke Kentucky, the following recommendations are being made to be addressed in its next IRP:

**Recommendation:** The Company should include all environmental costs, as they become known, in future benefit/cost analysis.
**Response**: The inputs used in the DSMore software to evaluate the cost effectiveness of the current DSM programs included the expected impact of carbon prices and other environmental costs as part of the Avoided Production Costs at the time of the most recent Portfolio Filing in 2012.

**Recommendation:** The Company should more closely monitor its DSM charges in order to prevent large over-collection of DSM charges.
**Response**: The annual program update filing captures the DSM charges and minimizes the amount of adjustments to prior period collection of DSM charges. In the filings made since the last IRP filing in 2011, processes have been implemented to minimize the amounts of over-collection of DSM charges.

**Recommendation:** The Company should more closely monitor its tariffs in order to ensure that all are current and in accordance with Commission requirements.
**Response**: Tariffs are updated annually as needed to address any program changes.

**Recommendation:** The Company should identify and explain all impacts to DSM resulting from changing its independent transmission operator from MISO to PJM.
**Response**: Duke Energy Kentucky moved from MISO to PJM effective January 1, 2012. Since that time changes have occurred in the MISO and PJM markets regarding DR programs and how they interact in the RTO markets. The list below provides significant changes to the DSM programs (i.e., Power Manager and PowerShare) resulting from the transition to PJM.

1. Emergency Event Notice: Upon the transition to PJM, the longest available notice of an emergency event that requires customers to curtail load is 2 hours to qualify the resource as capacity. MISO provided up to 12 hours' notice for a load management resource to qualify as capacity.
2. Testing Requirement: Upon the transition to PJM, all registered capacity resources are required to test each year for 1 hour if they are not called for an emergency event. MISO also required 1-hour testing of customers who used on-site generators as their load reduction method. However, MISO only required a mock test for customers who actually reduce load. For these customers who actually reduce load, an actual load reduction was not required.
3. Processing and Administration: Upon the transition to PJM, back office process changes were required. At a high level, MISO and PJM have similar needs and requirements related to DSM programs. However, their process can be significantly different such as the registration process for participants, the capacity participation process, and operational information processes.

In conclusion, from the participant's perspective, there were very few changes in the programs other than items 1 and 2 above. And essentially, for Power Manager participants, these changes did not impact the participants in any different manner than they were impacted in MISO. Today, PJM DR participation continues to evolve and change to address market needs. Changes to Power Manager and PowerShare program requirements may be necessary as new PJM market requirements take effect.

**Recommendation:** The Company should continue to review other cost-effective DSM or energy efficiency programs to include in its DSM portfolio

**Response**: Through the ongoing Collaborative process and a focus on developing new cost-effective program offerings, Duke Energy has a well-established process for identifying and bringing to market EE and DSM programs that are appropriate for the customers of Duke Energy Kentucky.

**2011 IRP Commission Response #3, Renewables and Distributed Generation**

**Recommendation:** Duke Kentucky included consideration of renewable generation in its modeling and provide some discussion of various types of that generation in its consideration of possible renewable power. Although, Duke Kentucky provided some reasonably in-depth discussion of renewable generation, it should also consider more discussion of its consideration of, and efforts in promoting, various forms of distributed generation in the next IRP filing. In addition, Duke Kentucky should continue to provide information related to the net metering statistics and activities of its customers in future IRPs.

**Response - Distributed Generation:** The response to this comment is addressed in Sections 5.C, 5.E. and 5.F.1.(Technical Screening – Advanced energy storage)

**Response – Net Metering:** As of April 30, 2014, Duke Energy Kentucky had 29 net metering customers with cumulative connected capacity of 0.6 MW. All of this capacity is supplied by inverter-based photovoltaic (PV) generation. Of these 29 customers that are net metered, 20 are single-family residential, 2 are multi-unit residential, 3 are schools, and 4 are commercial businesses. The largest PV system, at 0.39 MW, is at one of the schools. Except for one of the other schools and one commercial business, all the other customers have generating capacities less than 10 kW.

## 2011 IRP Commission Response #4, Generation Efficiency

**Recommendation:** Duke Kentucky provided discussion under the requirements of Section 8(2) in 807 KAR 5:058 requiring utilities to describe and discuss all options considered for inclusion in their plan, including improvements to and more efficient utilization of existing power generation, transmission and distribution facilities. In addition, the Commission in Administrative Case No. 2007-00300, in the August 25, 2009 Order, specifically noted this requirement and directed jurisdictional generators to focus greater research on cost-effective generation efficiency initiatives and to include a full, detailed discussion of such efforts. Duke Kentucky also gave consideration of the requirements of the Federal Energy Policy Act of 2005 Regarding Fuel Sources and Fossil Fuel Generation Efficiency, which was also in the Commission's directive in Admin. Case No. 2007-00300. Duke Kentucky knows and has stated accurately that generation outage planning is important to its reliability plan, These planned outages remove a generating unit from production typically during periods of lowest demand - usually occurring in the spring and fall - in order to perform work on pre-determined specific components. Such planned maintenance of coal-fired generating units is vital to the power production process and helps avoid forced outage maintenance, requiring a unit to be removed from service unexpectedly and immediately.

**Response:** Duke Energy Kentucky has a formal capital project development and approval program. As part of the cost/benefit analysis, efficiency impacts are evaluated in this process. Specifically, we have evaluated projects at East Bend like high-pressure/intermediate-pressure dense pack turbine technology and air preheater design evaluations to determine if they make prudent financial sense, and thus far they have not. From an O&M perspective, we have recently executed maintenance projects that impact efficiency at East Bend. In particular, the High Pressure Turbine (HPT) Foam Wash implemented during the Spring 2013 outage brought the HPT efficiency from 78.6% to 82.0% (versus original design of 84.5%). Additionally, during the 2014 Spring outage, the East Bend boiler was chemically cleaned to help recover some heat transfer efficiency.

## 2011 IRP Commission Response #5, Compliance Planning

**Recommendation:** Section 8(5)(f) of 807 KAR:5058 requires jurisdictional utilities to include a description and discussion of actions to be undertaken during the period covered by the plan, typically 15 years, but in this case 20 years, to meet the requirements of the Clean Air Act amendments of 1990, and an examination of how these actions affect the utility's resource assessment. Staff at this point mentions the Commission's expectation that environmental planning be performed comprehensively, considering not only existing and pending regulations, but also those reasonably anticipated including, but not limited to, regulation of $CO_2$. Comprehensive planning is essential in ensuring that compliance measures proposed be implemented. It also gives the Commission adequate time to perform its statutory duties in determining that new facilities and modifications are necessary in order to provide safe and adequate service, and that the rates charged are fair, just, and reasonable. A complete discussion of compliance actions and plans relating to current and pending environmental regulations should always be included in any IRP filing.

**Response:** The response to this comment is addressed in Chapters 6 and 8.

## 2011 IRP Commission Response #6, DR-01-005: Miami Fort 6 Update

**Recommendation:** Duke Kentucky should provide updates on its retirement of Miami Fort 6 process and its planned replacement alternatives progress. In regard to the retirement of Miami Fort 6, the response to Item 5 of Staff's First Request states: "Duke Energy Kentucky believes a decision must be made by mid-year 2012 to determine how to proceed with replacing Miami Fort 6 with combine cycle generation capacity in 2015. The generic CC selected by the model is viewed as an indicator of the type of capacity needed at that time. The generic combined cycle that is commercially available is much larger than 140 MW selected by the model. The approximate length of time from contract to completion of construction is four years for a 650 MW CC unit that is commercially available." Provide an update to this response.

Also, provide an update to the response to Item 14 of Staff's First Request, which states: There is no expectation for existing coal-fired generation to be retired in the next two years. In the short term, power will be purchased according to guidelines specified as a participant in the Midwest IS0 and then by PJM when the transfer occurs in 2012. The need for capacity on a longer term basis will be determined by mid-year 2012.

**Response:** The response to this comment is addressed in Chapter 8.

**2011 IRP Commission Response #7, DR-01-014: Reserve Margin Update**

**Recommendation:** It appears that Duke did not perform a reserve margin study. If such a study has been, or will be done, Duke should provide it in the next IRP, or clearly explain why it is not necessary to perform such a study. If Duke is required to meet PJM requirements and those suffice, provide a discussion of the reasonableness of those requirements.

**Response:** The determination of the planning reserve margin as specified by PJM is in Section 2.C. This is a reasonable requirement since PJM is responsible for overall electrical system reliability and economy in its control area, and it makes reserve margin requirements for member generating-entities, including Duke Energy Kentucky, to meet these responsibilities. Duke Energy Kentucky customers have greater energy security due to the reserve margin of all PJM generating entities that can be called upon when any PJM-connected generating unit is forced offline unexpectedly.

DUKE ENERGY.

*Kentucky*

# The Duke Energy Kentucky 2014 Integrated Resource Plan

## July 1, 2014

## Appendix F – Transmission & Distribution

**APPENDIX F – TRANSMISSION & DISTRIBUTION**
**Table of Contents**

## 1. PREFACE

This Appendix contains information that addresses the Transmission and Distribution requirements of 807 KAR 5:058.

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

## 3. SECTION 8. RESOURCE ASSESSMENT AND ACQUISITION PLAN

**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 transmission system in 2011-2013 for the purposes of increasing capacity and/or reliability:

- 2011: No transmission system improvements were implemented.
- 2012: No transmission system improvements were implemented.
- 2013: No transmission system improvements were implemented.

The following transmission system improvements are planned for 2014-2016:

- 2014: No transmission system improvements are planned.
- 2015: A 69 kV interconnection between Duke Energy Kentucky and East Kentucky Power Cooperative is planned for completion in 2015.
- 2016: No transmission system improvements are planned.

The following improvements were made to the distribution system in 2011-2013 for the purposes of increasing capacity and/or reliability:

- 2011: No distribution improvements were implemented.
- 2012: Grant 43 – Established new 12 kV distribution feeder.
- 2013: No distribution improvements were implemented.

The following distribution system improvements are planned for 2014, 2015, and 2016:

- 2014: No distribution system improvements are planned.
- 2015: The following distribution system improvements are planned.
    - Silver Grove Substation – Install new 138-12 kV, 22.4 MVA transformer.
    - Silver Grove 41, 42 & 43 – Establish three new 12 kV distribution feeders.
    - Crescent Substation – Install new 138-12 kV, 22.4 MVA transformer.
    - Crescent 45 & 46 – Establish two new 12 kV distribution feeders
- 2016: No distribution system improvements are planned.

**4. 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 2013 Transmission FERC Form 1

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report | Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|---|---|---|---|
| Duke Energy Kentucky, Inc. | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2013/Q4 | Duke Energy Kentucky, Inc. | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2013/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.

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.

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of | Size of Conductor | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | Structure (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | Circuits (h) | and Material (i) | Land (j) | Construction and Other Costs (k) | Total Cost (l) | Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | |
| 1 | 69KV TRANSMISSION POOL | | 69.00 | 69.00 | POLE | 102.18 | 3.04 | | | 1,094,542 | 12,522,063 | 13,616,605 | 44,712 | 249,861 | | 294,573 | 1 |
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| 36 | | | | | TOTAL | 102.18 | 3.04 | | | 1,094,542 | 12,522,063 | 13,616,605 | 44,712 | 249,861 | | 294,573 | 36 |

# Table F-2 2013 Distribution 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 2013/Q4 |

## 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 MVa 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 accounts affected in respondent's books of account. 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 MVa) 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 (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ALEXANDRIA SOUTH-CAMPBELL CO | UNATTENDED - D | 69.00 | 13.20 | | 11 | 1 | | | | | 1 |
| 2 | AUGUSTINE-COVINGTON, KY | UNATTENDED - D | 138.00 | 13.20 | | 72 | 2 | | | | | 2 |
| 3 | BEAVER-BOONE CO. | UNATTENDED - D | 69.00 | 13.20 | | 21 | 2 | | | | | 3 |
| 4 | BELLEVUE-CAMPBELL CO. | UNATTENDED - D | 138.00 | 13.20 | | 45 | 2 | | | | | 4 |
| 5 | BLACKWELL-GRANT CO. | UNATTENDED - T | 138.00 | 69.00 | | 150 | 1 | | | | | 5 |
| 6 | BUFFINGTON-KENTON CO. | UNATTENDED - T&D | 138.00 | 69.00 | 13.20 | 328 | 5 | | | | | 6 |
| 7 | CLARYVILLE-CAMBELL CO. | UNATTENDED - D | 69.00 | 13.20 | | 32 | 3 | | | | | 7 |
| 8 | COLD SPRING-KENTON CO. | UNATTENDED - D | 138.00 | 13.20 | | 33 | 2 | | | | | 8 |
| 9 | CONSTANCE-KENTON CO. | UNATTENDED - D | 138.00 | 13.20 | | 45 | 2 | | | | | 9 |
| 10 | COVINGTON - KENTON CO. | UNATTENDED - D | 69.00 | 13.20 | | 22 | 1 | | | | | 10 |
| 11 | CRESCENT-KENTON CO. | UNATTENDED - D | 138.00 | 13.20 | | 45 | 2 | | | | | 11 |
| 12 | CRITTENDEN-GRANT CO. | UNATTENDED - D | 69.00 | 13.20 | | 21 | 2 | | | | | 12 |
| 13 | DAYTON - CAMPBELL CO. | UNATTENDED - D | 138.00 | 13.20 | | 22 | 1 | | | | | 13 |
| 14 | DECOURSEY-KENTON CO. | UNATTENDED - D | 69.00 | 13.20 | | 11 | 1 | | | | | 14 |
| 15 | DIXIE-BOONE CO. | UNATTENDED - D | 69.00 | 13.20 | | 42 | 2 | | | | | 15 |
| 16 | DONALDSON-KENTON CO. | UNATTENDED - D | 138.00 | 13.20 | | 45 | 2 | | | | | 16 |
| 17 | DRY RIDGE-GRANT CO. | UNATTENDED - D | 69.00 | 13.20 | | 11 | 1 | | | | | 17 |
| 18 | EMPIRE - BOONE CO. | UNATTENDED - D | 69.00 | 13.20 | | 25 | 2 | | | | | 18 |
| 19 | FLORENCE-BOONE CO. | UNATTENDED - D | 138.00 | 13.20 | | 67 | 3 | | | | | 19 |
| 20 | GRANT-GRANT CO. | UNATTENDED - D | 69.00 | 13.20 | | 21 | 2 | | | | | 20 |
| 21 | HANDS-KENTON CO. | UNATTENDED - D | 138.00 | 13.20 | | 45 | 2 | | | | | 21 |
| 22 | HEBRON- BOONE CO. | UNATTENDED - D | 138.00 | 13.20 | | 45 | 2 | | | | | 22 |
| 23 | KENTON-KENTON CO. | UNATTENDED - T&D | 138.00 | 13.20 | | 165 | 3 | | | | | 23 |
| 24 | KY. UNIVERSITY-CAMP. CO. | UNATTENDED - D | 138.00 | 13.20 | | 45 | 2 | | | | | 24 |
| 25 | LIMABURG-BOONE CO. | UNATTENDED - D | 69.00 | 13.20 | | 31 | 3 | | | | | 25 |
| 26 | LONGBRANCH- BOONE CO. | UNATTENDED - D | 138.00 | 13.20 | | 22 | 1 | | | | | 26 |
| 27 | MARSHALL-CAMPBELL CO. | UNATTENDED - D | 69.00 | 13.20 | | 11 | 1 | | | | | 27 |
| 28 | MT ZION - BOONE CO. | UNATTENDED - D | 138.00 | 13.20 | | 22 | 1 | | | | | 28 |
| 29 | OAKBROOK - BOONE CO | UNATTENDED - D | 69.00 | 13.20 | | 22 | 1 | | | | | 29 |
| 30 | RICHWOOD-BOONE CO. | UNATTENDED - D | 69.00 | 13.20 | | 32 | 3 | | | | | 30 |
| 31 | THOMAS MORE - KENTON CO. | UNATTENDED - D | 69.00 | 13.20 | | 22 | 1 | | | | | 31 |
| 32 | VERONA - KENTON CO. | UNATTENDED - D | 69.00 | 13.20 | | 11 | 1 | | | | | 32 |
| 33 | VILLA-CRESTVIEW HLS., KY | UNATTENDED - D | 69.00 | 13.20 | | 45 | 2 | | | | | 33 |
| 34 | WHITE TOWER-KENTON CO. | UNATTENDED - D | 69.00 | 13.20 | | 21 | 2 | | | | | 34 |
| 35 | WILDER-WILDER, KY | UNATTENDED - T&D | 138.00 | 69.00 | 13.20 | 167 | 3 | | | | | 35 |
| 36 | YORK-NEWPORT, KY | UNATTENDED - D | 138.00 | 13.20 | | 22 | 1 | | | | | 36 |
| 37 | NO STATIONS UNDER 10 MVA | | | | | | | | | | | 37 |
| 38 | | | | | | | | | | | | 38 |
| 39 | | | | | | | | | | | | 39 |
| 40 | Summary of Listed Stations Above | | | | | | | | | | | 40 |

| 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 2013/Q4 |

## SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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3. Substations with capacities of Less than 10 MVa 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).

## SUBSTATIONS (Continued)

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 accounts affected in respondent's books of account. 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 MVa) 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 (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | (By Function) not including Commonly Owned | | | | | | | | | | | 1 |
| 2 | Substations | | | | | | | | | | | 2 |
| 3 | | | | | | | | | | | | 3 |
| 4 | UNATTENDED - T&D | | | | | 660 | | | | | | 4 |
| 5 | UNATTENDED - D | | | | | 986 | | | | | | 5 |
| 6 | UNATTENDED - T | | | | | 150 | | | | | | 6 |
| 7 | ATTENDED - T&D | | | | | | | | | | | 7 |
| 8 | ATTENDED - D | | | | | | | | | | | 8 |
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Kentucky

# The Duke Energy Kentucky 2014 Integrated Resource Plan

## July 1, 2014

## Appendix G – Index

# APPENDIX G – INDEX
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**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 |
|---|---|
| Scott Park | Integrated Resource Planning |
| Kevin Delehanty | Market Analytics |
| Leon Brunson | Load Forecasting |
| Bryan Walsh | Generation Operations Support |
| Neil Kern | Analytical Engineering |
| Jeff Turner | Transmission Planning |
| Jeff Turner | Distribution Planning |
| Mike Stroben and Keith Pike | Environmental |
| Darcy Pach and Tom Wiles | DSM and Renewables |

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| Section 2 | No Reponse Required |
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