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RECEIVE
MAY 15 2014
PUBLIC SERVICE COMMISSION

May 14, 2014

Mr. Jeff Derouen
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: Big Rivers Electric Corporation's 2014 Integrated Resource Plan

Dear Mr. Derouen:

Enclosed in connection with the 2014 Integrated Resource Plan ("IRP") of Big Rivers Electric Corporation are the following:

1. An original and ten (10) copies of a Petition for Confidential Treatment for portions of the 2014 IRP;

2. One (1) sealed copy of the portions of the IRP being filed under the Petition for Confidential Treatment with the confidential information underscored, highlighted with transparent ink, printed on yellow paper, on a CD marked confidential, or otherwise marked confidential;

3. Ten (10) copies of the IRP with the confidential information redacted; and

4. One (1) additional, unbound copy of the IRP with the confidential information redacted.

Appendix B and Appendix E to the IRP are being provided not only in hard copy, but they are also being provided electronically for convenience.

Pursuant to 807 KAR 5:058 Section 2(2), by copy of this letter, Big Rivers hereby provides notice to the intervenors in its last IRP review proceeding, Case No. 2010-00443, that the 2014 IRP has been filed with the Kentucky Public Service Commission and is available from Big Rivers upon request.

Big Rivers notes that, by order dated January 29, 2013, in Case No. 2013-00034, the Public Service Commission granted Big Rivers an extension until May 15, 2014, to file its 2014 IRP.

Telephone (270) 926-4000
Telecopier (270) 683-6694

100 St. Ann Building
PO Box 727
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If you have any questions about this filing, please do not hesitate to contact me.

Sincerely,

Tyson A. Kamuf

TAK/lm
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RECEIVED
MAY 15 2014
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

THE 2014 INTEGRATED RESOURCE PLAN OF) CASE NO. ____________
BIG RIVERS ELECTRIC CORPORATION)

PETITION OF BIG RIVERS ELECTRIC CORPORATION FOR CONFIDENTIAL TREATMENT

1. Big Rivers Electric Corporation ("Big Rivers") hereby petitions the Kentucky Public Service Commission ("Commission"), pursuant to 807 KAR 5:001 Section 13 and KRS 61.878, to grant confidential treatment to certain information contained in Big Rivers' 2014 Integrated Resource Plan ("IRP") filed with this petition. The information for which Big Rivers seeks confidential treatment is hereinafter referred to as the "Confidential Information."

2. The Confidential Information is provided in either hardcopy or electronic format. One (1) copy of the hardcopy pages containing Confidential Information with the Confidential Information underscored, highlighted with transparent ink, printed on yellow paper, or otherwise marked "CONFIDENTIAL," is being filed with this petition in a separate sealed envelope marked "CONFIDENTIAL." A copy of those pages, with the Confidential Information redacted, is being filed with the original and each of the ten (10) copies of the responses to the data requests filed with this petition. *See* 807 KAR 5:001 Sections 13(2)(a)(3), 13(2)(b).

3. One (1) copy of the electronic files containing Confidential Information is contained in the confidential electronic files that accompany this petition. The entirety of these confidential files have been redacted from the original and each of the ten (10) copies of the responses to the data requests filed with this petition. *See* 807 KAR 5:001 Sections 13(2)(a)(3), 13(2)(b).

4. A copy of this petition with the Confidential Information redacted has been served on all parties to this proceeding. *See* 807 KAR 5:001 Section 13(2)(c).

5. The Confidential Information is not publicly available, is not disseminated within Big Rivers except to those employees and professionals with a legitimate business need to know and act upon the information, and is not disseminated to others without a legitimate need to know and act upon the information.

6. If and to the extent the Confidential Information becomes generally available to the public, whether through filings required by other agencies or otherwise, Big Rivers will notify the Commission in writing. *See* 807 KAR 5:001 Section 13(10)(b).

7. As discussed below, the Confidential Information is entitled to confidential treatment based upon KRS 61.878(1)(m), or KRS 61.878(1)(c)(1). *See* 807 KAR 5:001 Section 13(2)(a)(1).

I. Information Exempted from Public Disclosure by KRS 61.878(1)(m)

8. KRS 61.878(1)(m)(1) protects "[p]ublic records the disclosure of which would have a reasonable likelihood of threatening the public safety by exposing a vulnerability in preventing protecting against, mitigating, or responding to a terrorist act. . . ."

9. Figure 1.3 and Appendix E are transmission system maps, which could be used to analyze vulnerable locations in Big Rivers' transmission system, which is a public utility critical system, and which could therefore threaten public safety. As disclosure of this information would provide the public with a tool to analyze the vulnerabilities in Big Rivers' transmission system, this information should be granted confidential treatment.

II. <u>Information Exempted from Public Disclosure by KRS 61.878(1)(c)(1)</u>

A. Big Rivers Faces Actual Competition.

10. KRS 61.878(1)(c)(1) protects "records confidentially disclosed to an agency or required by an agency to be disclosed to it, generally recognized as confidential or proprietary, which if openly disclosed would permit an unfair commercial advantage to competitors of the entity that disclosed the records."

11. As a generation and transmission cooperative, Big Rivers competes in the wholesale power market. This includes not only the short-term bilateral energy market, the day-ahead and real time energy and ancillary services markets, and the annual capacity market to which Big Rivers has access by virtue of its membership in Midcontinent Independent System Operator, Inc. ("MISO"), but also forward bilateral long-term agreements and wholesale agreements with utilities and industrial customers. Big Rivers' ability to successfully compete in the market is dependent upon a combination of its ability to: 1) obtain the maximum price for the power it sells, and 2) keep its cost of production as low as possible. Fundamentally, if Big Rivers' cost of producing a unit of power increases, its ability to sell that unit in competition with other utilities is adversely affected.

12. Big Rivers also competes for reasonably priced credit in the credit markets, and its ability to compete is directly impacted by its financial results. Lower revenues and any events that adversely affect Big Rivers' margins will adversely affect its financial results and potentially impact the price it pays for credit. A competitor armed with Big Rivers' proprietary and confidential information will be able to increase Big Rivers' costs or decrease Big Rivers' revenues, which could in turn affect Big Rivers' apparent creditworthiness. A utility the size of Big Rivers that operates generation and transmission facilities will always have periodic cash

and borrowing requirements for both anticipated and unanticipated needs. Big Rivers expects to be in the credit markets on a regular basis in the future, and it is imperative that Big Rivers improve and maintain its credit profile.

13. Accordingly, Big Rivers has competitors in both the power and capital markets, and its Confidential Information should be protected to prevent the imposition of an unfair competitive advantage.

B. The Confidential Information is Generally Recognized as Confidential or Proprietary.

14. The Confidential Information for which Big Rivers seeks confidential treatment under KRS 61.878(1)(c)(1) is generally recognized as confidential or proprietary under Kentucky law.

15. The Confidential Information in the body of the 2014 IRP consists of projected energy and demand requirements, projected generation levels, fuel cost projections, capacity requirements, and projected capacity costs.

16. Appendix A of the 2014 IRP contains Big Rivers' proprietary and confidential 2013 Load Forecast.

17. The Confidential Information contained in Appendix F consists of projected production costs, including projected fuel and other operating and maintenance ("O&M") costs, and projected generation and outage information.

18. The Confidential Information contained in Appendix G consists of projected market capacity sales information.

19. The Confidential Information contained in Appendix H consists of model outputs including projected production costs, such as projected fuel and other O&M costs.

20. Public disclosure of the Confidential Information would reveal detailed information relating to Big Rivers' projected production costs for production factors such as fuel and other O&M costs, and Big Rivers' projection of capacity market prices. This information provides insight into Big Rivers' cost of producing power and would indicate the prices at which Big Rivers is willing to buy or sell power and production factors. The information is also indicative of the market conditions Big Rivers expects to encounter and its ability to compete with competitors. The Commission has previously granted confidential treatment to similar information. *See, e.g.*, *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Order, P.S.C. Case No. 2012-00535 (April 25, 2013) (the "April 25 Confidentiality Order"); *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Order, P.S.C. Case No. 2012-00535 (August 14, 2013); *In the Matter of: Application of Big Rivers Electric Corporation for Approval of its 2012 Environmental Compliance Plan, for Approval of its Amended Environmental Cost Recovery Surcharge Tariff, for Certificates of Public Convenience and Necessity, and for Authority to Establish a Regulatory Account*, Letter, P.S.C. Case No. 2012-00063 (August 15, 2012).

21. Public disclosure of information relating to Big Rivers' projected generation levels and planned outages would reveal when Big Rivers will have power available to sell into the market, or when Big Rivers' generation levels will drop due to maintenance and construction and will have to resort to purchased power to meet its native load. The Commission has previously granted confidential treatment to similar information. *See, e.g.*, April 25 Confidentiality Order, P.S.C. Case No. 2012-00535; P.S.C. Administrative Case No. 387, Letter (July 20, 2010).

22. Public disclosure of the 2013 Load Forecast and projected energy and demand requirements would reveal Big Rivers' fundamental financial data and projections, and current and forecasted load demand. This type of information bears upon a company's detailed inner workings and is generally recognized as confidential or proprietary. *See*, *e.g.*, *Hoy v. Kentucky Indus. Revitalization Authority*, 907 S.W.2d 766, 768 (Ky. 1995) ("It does not take a degree in finance to recognize that such information concerning the inner workings of a corporation is 'generally recognized as confidential or proprietary'"). The confidential nature of these communications is essential to fully-informed corporate governance as the directors must be able to conduct open and frank discussions if they are to discharge their responsibilities to Big Rivers and its members. Additionally, the Commission has previously granted confidential treatment to this type of information. *See, e.g.,* April 25 Confidentiality Order, P.S.C. Case No. 2012-00535 (granting confidential treatment to minutes of the Big Rivers Board of Directors, Big Rivers' Financial Model, and Big Rivers' load forecast); *In the Matter of: An Examination of the Application of the Fuel Adjustment Clause of East Kentucky Power Cooperative, Inc. From November 1, 2011 Through April 30, 2012*, Order, P.S.C. Case No. 2012-00319 (February 21, 2013).

C. Disclosure of the Confidential Information Would Result in an Unfair Commercial Advantage to Big Rivers' Competitors.

23. Disclosure of the Confidential Information would grant Big Rivers' competitors an unfair commercial advantage. As discussed above in Section II. A, Big Rivers faces actual competition in both the short- and long-term wholesale power markets and in the credit markets. Big Rivers' ability to compete in these markets would be adversely affected if the Confidential Information were publicly disclosed, and Big Rivers seeks protection from such competitive injury.

24. The Confidential Information includes material such as Big Rivers' projections of fuel costs and capacity market prices. If that information is publicly disclosed, market participants would have insight into the prices at which Big Rivers is willing to buy and sell fuel and could manipulate the bidding process, impairing its ability to generate power at competitive rates and thus to compete in the wholesale power markets. Furthermore, any competitive pressure that adversely affects Big Rivers' revenue and margins could make the company appear less creditworthy and thus impair its ability to compete in the credit markets. These effects were recognized in P.S.C. Case No. 2003-00054, in which the Commission granted confidential treatment to bids submitted to Union Light, Heat & Power ("ULH&P"). ULH&P argued, and the Commission implicitly accepted, that if the bids it received were publicly disclosed, contractors in the future could use the bids as a benchmark, which would likely lead to the submission of higher bids. *In the Matter of: Application of the Union Light, Heat and Power Company for Confidential Treatment*, Order, PSC Case No. 2003-00054 (August 4, 2003); *accord An Examination of the Application of the Fuel Adjustment Clause of East Kentucky Power Cooperative, Inc. From May 1, 2007 Through October 31, 2007*, Letter, P.S.C. Case No. 2007-00523 (February 27, 2008). The Commission also implicitly accepted ULH&P's further argument that the higher bids would lessen ULH&P's ability to compete with other gas suppliers. *Id.* Similarly, potential fuel and power suppliers manipulating Big Rivers' bidding process would lead to higher costs or lower revenues to Big Rivers and would place it at an unfair competitive disadvantage in the wholesale power market and credit markets.

25. Potential market power purchasers could use the information related to Big Rivers' projected generation levels, generator availability, planned outages, and future planning to know when Big Rivers will have power to sell into the wholesale market and could use that

information to manipulate their bids, leading to lower revenues to Big Rivers and placing it at an unfair competitive disadvantage in the credit markets.

26. Public disclosure of the prices of fuel and other variable cost information, and information about Big Rivers' wholesale power needs would give the power producers and marketers with which Big Rivers competes in the wholesale power market insight into Big Rivers' cost of producing power and need for power and energy during the periods covered by the information. Knowledge of this information would give those power producers and marketers an unfair competitive advantage because they could use that information to potentially underbid Big Rivers in wholesale transactions. It would also give potential suppliers to Big Rivers a competitive advantage because they will be able to manipulate the price of power bid to Big Rivers in order to maximize their revenues, thereby driving up Big Rivers' costs and impairing Big Rivers' ability to compete in the wholesale power and credit markets.

27. Finally, the Commission has consistently recognized that internal strategic planning information and related materials are entitled to confidential treatment, as these documents typically relate to the company's economic status and business strategies. *See, e.g., Marina Management Servs. v. Cabinet for Tourism, Dep't of Parks*, 906 S.W.2d 318, 319 (Ky. 1995) (unfair commercial advantage arises simply from "the ability to ascertain the economic status of the entities without the hurdles systemically associated with the acquisition of such information about privately owned organizations"); *In the Matter of: The Joint Application of Duke Energy Corp., Cinergy Corp., Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., Diamond Acquisition Corp., and Progress Energy, Inc., for Approval of the Indirect Transfer of Control of Duke Energy Kentucky, Inc.*, P.S.C Case No. 2011-00124 (Dec. 5, 2011); *In the Matter of: The Joint Petition of Kentucky-American Water Co., Thames Water Aqua Holdings*

GmbH, RWE Aktiengesellschaft, Thames Water Aqua U.S. Holdings, Inc., and Am. Water Works Co., Inc. for Approval of a Change in Control of Kentucky-American Water Co., P.S.C. Case No. 2006-00197 (Aug. 29, 2006) ().

28. Accordingly, the public disclosure of the information that Big Rivers seeks to protect would provide Big Rivers' competitors with an unfair commercial advantage.

III. Time Period

29. Pursuant to 807 KAR 5:001 Section 13(2)(a)(2), Big Rivers requests that the Confidential Information be afforded confidential period for the time periods explained below.

30. Big Rivers requests that the Confidential Information protected by KRS 61.878(1)(m) remain confidential indefinitely because as long as the transmission system remains in place, the information should be confidential for the reasons stated above.

31. Big Rivers requests that the Confidential Information protected by KRS 61.878 (1)(c)(1) remain confidential for a period of five (5) years from the date of this petition, which should allow sufficient time for the projected data to become historical and sufficiently outdated that it could not be used to determine similar confidential information at that time or to competitively disadvantage Big Rivers.

IV. Conclusion

32. Based on the foregoing, the Confidential Information is entitled to confidential treatment pursuant to 807 KAR 5:001 Section 13 and KRS 61.878. If the Commission disagrees that Big Rivers' Confidential Information is entitled to confidential treatment, due process requires the Commission to hold an evidentiary hearing. *Utility Regulatory Comm'n v. Kentucky Water Serv. Co., Inc.*, 642 S.W.2d 591 (Ky. App. 1982).

WHEREFORE, Big Rivers respectfully requests that the Commission grant this petition and classify and treat as confidential the Confidential Information.

On this the 14th day of May, 2014.

Respectfully submitted,

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Counsel for Big Rivers Electric Corporation

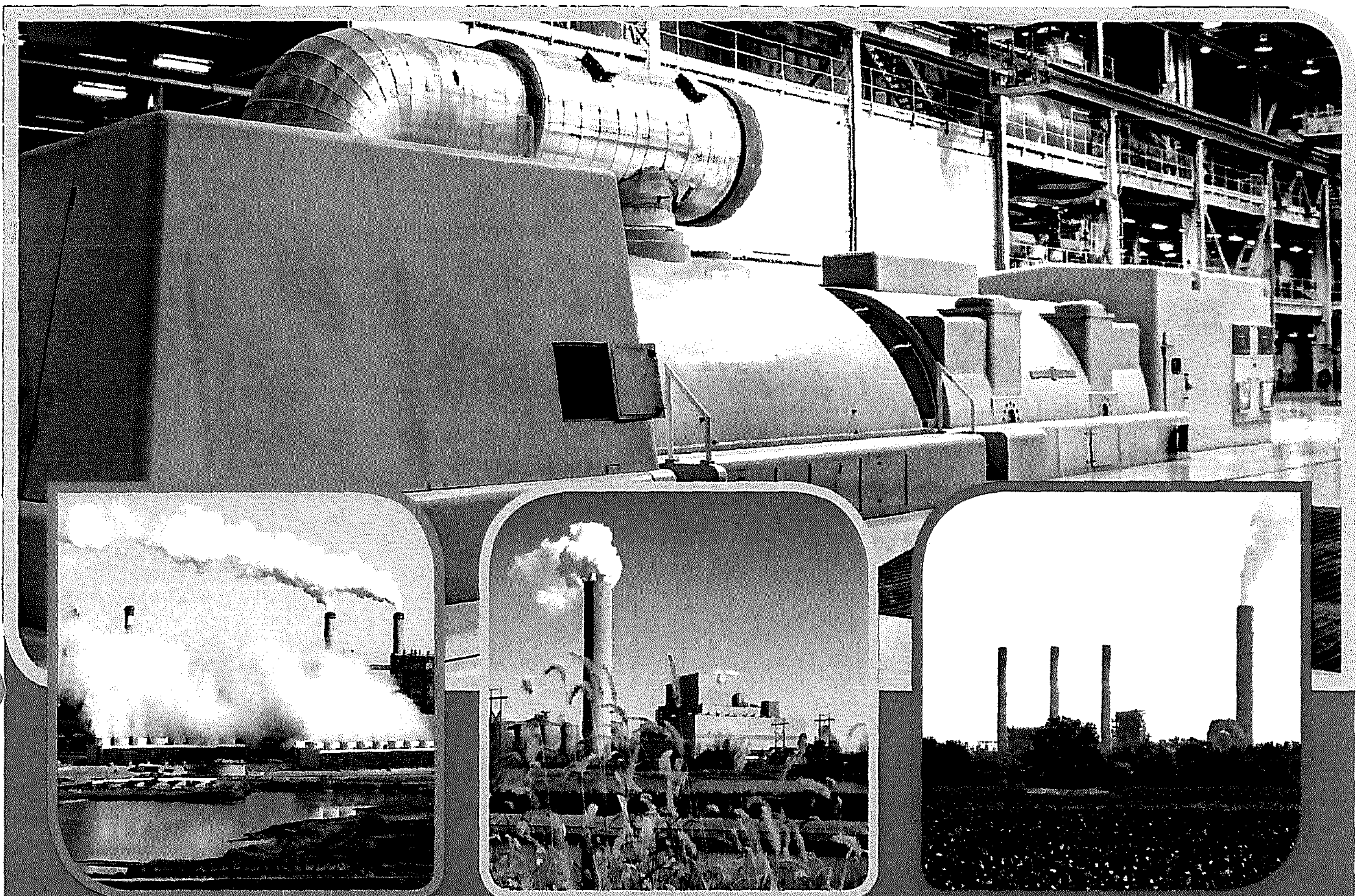
Certificate of Service

I certify that a true and accurate copy of the foregoing was or will be served by Federal Express or by hand delivery upon the persons listed on the accompanying service list, on or before the date this petition is filed with the Kentucky Public Service Commission.

On this the 14th day of May, 2014,

Counsel for Big Rivers Electric Corporation

Big Rivers
ELECTRIC CORPORATION



Big Rivers Electric Corporation

2014 INTEGRATED RESOURCE PLAN

May 15, 2014

Prepared in collaboration with:

GDS Associates, Inc.
Engineers and Consultants

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Appendix

A – 2013 Load Forecast
B – DSM Potential Study
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H – Strategist Model Outputs
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1. IRP Plan Summary

1.1 Overview of 2014 IRP

As an electric utility under the jurisdiction of the Kentucky Public Service Commission ("Commission"), Big Rivers Electric Corporation ("Big Rivers") must triennially file an Integrated Resource Plan ("IRP"). This 2014 IRP is provided to comply with Big Rivers' obligations under 807 KAR 5:058 and gives a comprehensive overview of Big Rivers' system and resource plans. It is grouped in logical sections to provide the reader with the information required by statute. A cross-reference table to the requirements of 807 KAR 5:058 is presented in Appendix D. A glossary of terms and acronyms used throughout this IRP are listed in Appendix H.

1.2 Introduction

Big Rivers filed its most recent IRP with the Commission on November 15, 2010, in Case No. 2010-00443[1] (the "2010 IRP"). Commission Staff issued a report summarizing its review of Big Rivers' 2010 IRP on December 12, 2011, and the proceeding was closed by order dated December 21, 2011. Big Rivers' next IRP was initially due in November 2013; however, the Commission granted Big Rivers a six-month extension, or until May 15, 2014, to file this IRP.[2]

This 2014 IRP was prepared by Big Rivers with the assistance of GDS Associates, Inc. ("GDS"). The individuals responsible for preparation of the IRP and who will be available to respond to inquiries are listed in Table 1.1.

Table 1.1
IRP Project Team

Company	*Name*	*Area of Expertise*
Big Rivers Electric Corporation	*Mark Bailey*	*President and CEO*
	Robert Berry	*Chief Operating Officer*
	Lindsay Barron, V.P.	*Project Management*
	Marlene Parsley	*Power Supply, Load Forecast*
	Russ Pogue	*Demand-Side Management*
	Duane Braunecker	*Production*
	Eric Robeson, V.P.	*Environmental/Emissions*
	Chris Bradley	*Transmission*
	Chris Warren	*Finance*
	Roger Hickman	*Regulatory Affairs*
GDS Associates, Inc.	*Brian Smith*	*Supply-Side Modeling*
	Warren Hirons *Jacob Thomas*	*Demand-Side Management*
	John Hutts	*Load Forecast*

[1] *In the Matter of: 2010 Integrated Resource Plan of Big Rivers Electric Corporation*, Case No. 2010-00043.

[2] See order dated January 29, 2013, *In the Matter of: Big Rivers Electric Corporation's Request for an Extension of Time to file its next Integrated Resource Plan*, Case No. 2013-00034.

This 2014 IRP presents Big Rivers' resource plan for meeting projected power requirements through 2028. This 2014 IRP presents the basis for the plan and the resulting actions Big Rivers will undertake with respect to meeting future load requirements through a portfolio of supply-side and demand-side resources. Supporting documents, figures, and tables are provided throughout this document and in the Appendices, which are an integral part of the 2014 IRP.

The remainder of this section contains a summary of Big Rivers, its generation and transmission assets, projected load growth, demand-side management ("DSM")[3] activities, and the resource plan developed to meet demand through 2028.

1.3 Description of the Utility

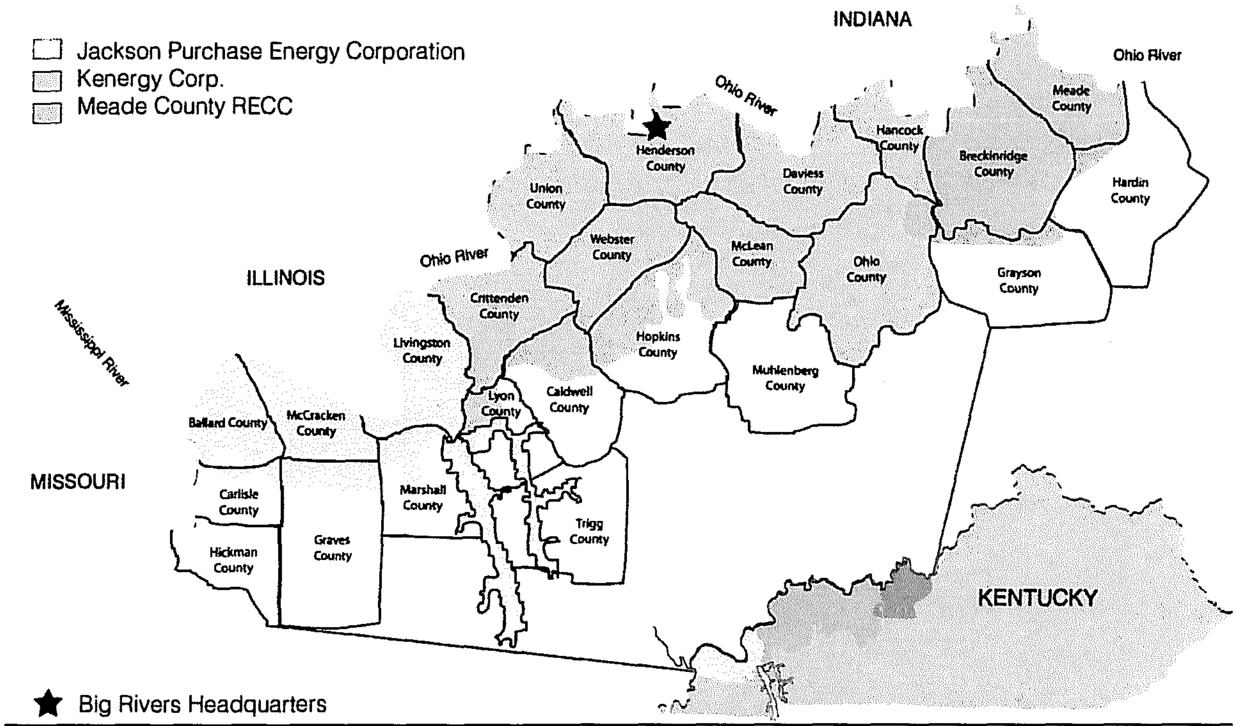
1.3.1 Overview

Big Rivers is a generation and transmission cooperative headquartered in Henderson, Kentucky. Big Rivers owns, operates and maintains electric generation and transmission facilities, and it purchases, transmits, and sells electricity at wholesale. It exists for the principal purpose of providing the wholesale electricity requirements of its three distribution cooperative member-owners, which are Jackson Purchase Energy Corporation ("JPEC"), Kenergy Corp. ("Kenergy"), and Meade County Rural Electric Cooperative Corporation ("MCRECC") (collectively, the "Members"). The Members, in turn, provide retail electric service to approximately 113,000 consumer-members located in all or parts of 22 western Kentucky counties: Ballard, Breckenridge, Caldwell, Carlisle, Crittenden, Daviess, Graves, Grayson, Hancock, Hardin, Henderson, Hopkins, Livingston, Lyon, Marshall, McCracken, McLean, Meade, Muhlenberg, Ohio, Union, and Webster. A map showing the Members' service territory is provided in Figure 1.1 on the following page.

Additionally, Big Rivers provides transmission and ancillary services to other entities under the Midcontinent Independent System Operator ("MISO") Tariff. Big Rivers' wholesale rates are presented in its tariff, which has an effective date of February 1, 2014, and which is on file with the Commission. That tariff may be accessed from either the Commission's website (http://www.psc.ky.gov/tariffs/Electric/) or from the Regulatory webpage of Big River's internet site (http://www.bigrivers.com/regulatory.aspx).

[3] In the context of Big Rivers' IRP, demand-side management is defined as all activities designed to impact electricity use, including demand response and energy efficiency programs.

Figure 1.1
Big Rivers' Members Service Area Map



1.3.2 Capacity Resources

Big Rivers owns and operates the Robert A. Reid Plant (130 MW), the Kenneth C. Coleman Plant (443 MW), the Robert D. Green Plant (454 MW), and the D. B. Wilson Plant (417 MW), totaling 1,444 net MW of generating capacity. Total generation resources are 1,819 MW, including rights currently to 197 MW at Henderson Municipal Power and Light's ("HMP&L") William L. Newman Station Two facility ("HMP&L Station Two")[4] and 178 MW of contracted hydro capacity from the Southeastern Power Administration ("SEPA").[5] Force majeure conditions on the SEPA system have reduced Big Rivers' total generation capacity to 1,641 MW at the present time, and Big Rivers expects SEPA to return to full capacity in 2015. See Figures 1.2a through 1.2c for an overview of Big Rivers' Generation Facilities.

[4] HMP&L has the contractual right to increase or decrease its capacity reservation from HMP&L Station Two by up to 5 MW each year.

[5] In this analysis, both HMP&L load and generation are included. HMP&L has rights to 12MW of SEPA capacity, which is assumed in this analysis to directly offset HMP&L load.

Figure 1.2a
Generation Facility Overview

D.B. WILSON STATION

Wilson Station consists of a single, pulverized coal generating unit located near Centertown, Kentucky with a total rated generating capacity of 417 Net MW.

The Wilson Station includes:

- Foster Wheeler boiler and Westinghouse turbine generator, commercialized in 1986.
- The flue gas desulphurization ("FGD") system is a MW Kellogg horizontal flow wet limestone FGD. The FGD system consists of four horizontal limestone reagent absorbers with a designed SO_2 removal rate of 90%.
- The electrostatic precipitator is designed to remove 99.87% of the particulate.
- The selective catalytic reduction ("SCR") system is a Babcock Borsig delta wing design that uses plate catalyst and ammonia reagent to remove 90% of the unit's NOx emissions.

Figure 1.2b
Generation Facility Overview

SEBREE STATION

Sebree Station consists of three stations: the Robert D. Green Station, the Robert A. Reid Station, and HMP&L Station Two, with a combined net generating capacity of 896 MW. The facility consists of six units: four coal-fired and two with dual fuel capabilities (one coal/gas and the other one oil/gas).

Robert D. Green Station

- 231 MW Green Unit 1 has a B&W boiler and GE turbine/generator, commercialized in 1979.
- 223 MW Green Unit 2 has a B&W boiler and Westinghouse turbine/generator, commercialized in 1981.
- Pollution control includes an American Air Filter FGD system designed for 97% removal of SO_2. Precipitator removes 99.2% particulate matter.

Robert A. Reid Station

- 65 MW Reid Unit 1 has a Riley boiler and GE turbine/generator, commercialized in 1966. It has been retrofitted to partially burn gas for SO_2 and NOx control, and its precipitator removes 98.9% particulate matter.
- 65 MW Reid Combustion Turbine is a GE Frame 7C, commercialized in 1976. It was retrofitted in 2001 to burn natural gas in addition to fuel oil for SO_2 and NOx control.

HMP&L Station Two

- 153 MW HMP&L Unit 1 has a Riley boiler and GE turbine/generator, commercialized in 1973. It was retrofitted with an FGD in 1995 for SO_2 control and an Alstom SCR in 2004 for NOx control.
- 159MW HMP&L Unit 2 has a Riley boiler and Westinghouse turbine/generator, commercialized in 1974. It was retrofitted with an FGD in 1995 for SO_2 control and an SCR in 2004 for NOx control.
- The selective catalytic reduction ("SCR") system is an Alstom delta wing design that uses plate catalyst and ammonia reagent to remove 90% of the unit's NOx emissions, the Wheelabrator FGD is designed to remove 92% SO_2, and precipitator removes 99.4% particulate matter for both units.

Figure 1.2c
Generation Facility Overview

KENNETH C. COLEMAN STATION

Coleman Station consists of three pulverized coal generating units located near Hawesville, Kentucky and has a total generating capacity of 443 Net MW.

The Coleman Station includes:

- 150 MW Coleman Unit 1 has a Foster Wheeler boiler and Westinghouse turbine generator, commercialized in 1969.
- 138 MW Coleman Unit 2 has a Foster Wheeler boiler and Westinghouse turbine generator, commercialized in 1970.
- 155 MW Coleman Unit 3 has a Riley boiler and GE turbine generator, commercialized in 1972.
- The FGD system is a Wheelabrator Air Pollution Control design. This unique design combines the three generating units into a single FGD absorber that utilizes limestone as a reagent, and with forced oxidation, produces market grade gypsum. First operation occurred in February 2006, and it was commercialized in May 2007.

1.3.3 Transmission System

Big Rivers owns, operates and maintains its 1,285 mile transmission system and provides for the transmission of power to its Members and third party entities served under the MISO tariff. A map of the transmission system is provided in Figure 1.3, and a more detailed map is provided in Appendix E. Discussion of Big Rivers' transmission planning is provided in Section 6.

Figure 1.3
Transmission System Map

[REDACTED]

1.3.4 Big Rivers' Load

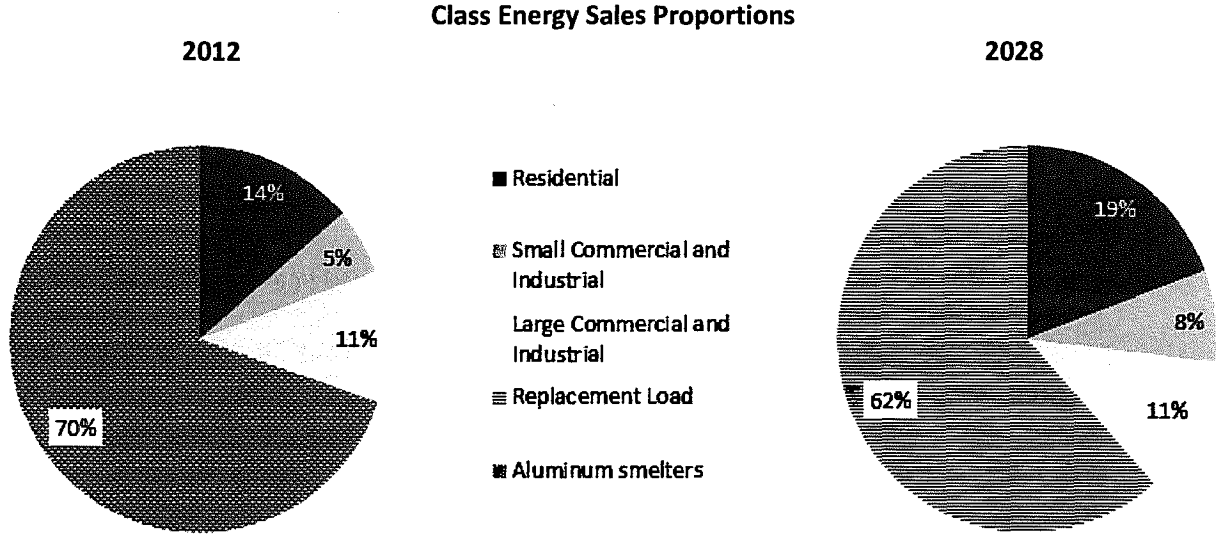
Unless otherwise noted, references to total system energy and peak demand requirements in this 2014 IRP are to load associated with Big Rivers' Members' native system, Big Rivers' off-system replacement load, and HMP&L requirements. Replacement load is defined as future sales served from approximately 800 MW of capacity available to Big Rivers and its Members as a result of two aluminum smelters terminating their retail electric service contracts effective August 20, 2013, and January 31, 2014, respectively. Refer to Section 4.2.4 for more discussion of replacement load.

Big Rivers categorizes energy and peak demand into two classes: rural system and large industrial. The rural system is comprised of all retail residential, commercial, and industrial customers served by Big

Rivers' Members, except for retail customers served under Big Rivers' Large Industrial Customer ("LIC") tariff. The direct-serve customers are designated as the large industrial class, which currently includes 21 large commercial and industrial customers. Approximately 90% of the accounts served by Big Rivers' Members are residential. A breakdown of actual energy sales for 2012 and projected sales for 2028 is presented in Figure 1.4.[6]

Historically, Big Rivers provided power to Kenergy for resale to two aluminum smelters. Due to the termination of the smelter contracts, effective in August 2013 and January 2014, respectively, Big Rivers no longer provides power for the smelters from its generation system, but power is transmitted to them over Big Rivers' transmission system. The contracts facilitating Big Rivers providing power in this manner were approved by the Commission in its orders dated August 14, 2013, and January 30, 2014, in Case Nos. 2013-00221[7] and 2013-00413,[8] respectively. In 2012, Member energy sales to the smelters comprised approximately 70 percent of total native load sales. Over the course of the forecast horizon, the majority of sales previously associated with the smelters is projected to be absorbed by replacement load sales. Replacement load sales are projected to account for 62 percent of total system sales by 2028.

Figure 1.4
Class Energy Sales Proportions



[6] Requirements associated with HMP&L are not reflected in Figure 1.4.

[7] *In the Matter of: Joint Application of Kenergy Corp. and Big Rivers Electric Corporation for Approval of Contracts and for a Declaratory Order*, Case No. 2013-00221.

[8] *In the Matter of: Joint Application of Kenergy Corp. and Big Rivers Electric Corporation for Approval of Contracts and for a Declaratory Order*, Case No. 2013-00413.

With the exceptions of Figure 1.4 and the 2013 Load Forecast, all historical and projected energy consumption and peak demand associated with the smelters have been excluded from the IRP analysis and all tables and graphs presented in the body this IRP.[9]

1.4 Planning Goals and Objectives

Big Rivers' primary planning goal in its 2014 IRP is to reliably provide for its customers' electricity needs over the next 15 years through an appropriate mix of supply and demand side options, at the lowest reasonable cost. Big Rivers has established the following planning objectives to guide its IRP process:

- Maintain a current and reliable load forecast,
- Continue to offer cost-effective DSM programs to its Members,
- Identify potential new supply side resources and DSM programs,
- Provide competitively priced power to its Members,
- Maintain adequate planning reserve margins,
- Maximize reliability while ensuring safety, minimizing costs, risks, and environmental impacts,
- Meet North American Electric Reliability Corporation ("NERC") guidelines and requirements.

1.5 Load Forecast Summary

Big Rivers' total energy and peak demand requirements are comprised of its native system load, replacement power, and HMP&L load. Total requirements include generation and transmission losses. Total system energy and peak demand requirements are presented in Table 1.2, and are projected to more than double existing levels over the next 15 years. Replacement load enters the forecast in 2016 and increases significantly before leveling off in 2021. Refer to Table 1.3 for a breakdown of the forecast by component.

[9] Big Rivers' 2013 Load Forecast is presented as Appendix A. The tables and graphs presented in that report include historical and projected energy and demand amounts for the two aluminum smelters through January 2014.

Table 1.2
2013 Load Forecast - Total System Requirements

	Energy Requirements (MWH)	*Peak Demand (MW)*	*Load Factor*
2009	*3,906,942*	*801*	*56%*
2010	*4,209,716*	*797*	*60%*
2011	*4,123,434*	*787*	*60%*
2012	*4,226,829*	*767*	*63%*
2013	*4,040,110*	*772*	*60%*
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]

Shaded year represents base year

Values are net of DSM and include HMP&L requirements and replacement load beginning in 2016 (see Section 4.2.4 for discussion of replacement load)

Native system energy and peak demand requirements are projected to [redacted] at average compound rates of [redacted]% and [redacted]%, respectively, per year from 2013 through 2028. Native energy requirements are projected to [redacted] in 2015 and 2016 in response to projected retail price increases. Native peak demand is projected to [redacted] by approximately [redacted] MW per year from 2013 through 2028. Replacement load enters the forecast in 2016 at 103 MW at 75% load factor and increases to 827 MW (including losses) at the same load factor by 2021.

Table 1.3
2013 Load Forecast – Total System Requirements by Component

	Native System		*Replacement Load*		*HMP&L*	
	Energy Requirements (MWH)	*Peak Demand (MW)*	*Energy Requirements (MWH)*	*Peak Demand (MW)*	*Energy Requirements (MWH)*	*Peak Demand (MW)*
2009	*3,315,499*	*690*			*591,442*	*111*
2010	*3,563,304*	*680*			*646,412*	*117*
2011	*3,501,035*	*674*			*622,398*	*113*
2012	*3,607,988*	*652*			*618,841*	*115*
2013	*3,413,551*	*655*			*626,559*	*117*
2014	[redacted]	[redacted]			[redacted]	[redacted]
2015	[redacted]	[redacted]			[redacted]	[redacted]
2016	[redacted]	[redacted]	*681,141*	*103*	[redacted]	[redacted]
2017	[redacted]	[redacted]	*1,358,561*	*207*	[redacted]	[redacted]
2018	[redacted]	[redacted]	*2,037,841*	*310*	[redacted]	[redacted]
2019	[redacted]	[redacted]	*2,717,122*	*414*	[redacted]	[redacted]
2020	[redacted]	[redacted]	*4,086,849*	*620*	[redacted]	[redacted]
2021	[redacted]	[redacted]	*5,434,243*	*827*	[redacted]	[redacted]
2022	[redacted]	[redacted]	*5,434,243*	*827*	[redacted]	[redacted]
2023	[redacted]	[redacted]	*5,434,243*	*827*	[redacted]	[redacted]
2024	[redacted]	[redacted]	*5,449,132*	*827*	[redacted]	[redacted]
2025	[redacted]	[redacted]	*5,434,243*	*827*	[redacted]	[redacted]
2026	[redacted]	[redacted]	*5,434,243*	*827*	[redacted]	[redacted]
2027	[redacted]	[redacted]	*5,434,243*	*827*	[redacted]	[redacted]
2028	[redacted]	[redacted]	*5,449,132*	*827*	[redacted]	[redacted]

Shaded year represents base year

Native system energy requirements in 2009-2013 reflect transmission losses adjusted to reflect exclusion of smelter load

Values are net of DSM

Key Economic and Demographic Influences - The key influences on the load forecast include economic activity, changes in retail prices, increases in heating and cooling equipment efficiencies, energy conservation, and the continued stable base of large industrial load. With respect to the economic and demographic influences, number of households is used to project the number of rural system customers, and average household income is one of the key inputs in the rural system energy model. Number of households and average household income are expected to show little growth over the forecast period and are contributing factors to projected low growth in number of customers and average energy consumption per customer over the next 15 years. Refer to Appendix A, 2013 Load Forecast, Section 4, for additional discussion on the economic outlook.

The forecast reflects projected increases in retail electricity prices of nearly 40% from 2014-2016 for rural system customers. For rural system customers, the elasticity of consumption with respect to price is -0.18 and was derived using the regression models developed to forecast average energy consumption for each Member distribution cooperative. Projections of energy and peak demand for the 20[10] large industrial customers included in the forecast were based on a qualitative approach that included consideration of price increases and customer ability to respond. After much discussion and consideration of customers' processes and operating characteristics, management concluded that energy sales and peak demand for these 20 customers would not decrease as a result of price increases planned in the near term.

The load forecast reflects impacts associated with changes in heating and cooling appliance market shares and increases in their respective efficiencies. Over the course of the forecast horizon, the market shares for both heating and cooling are projected to increase minimally. The efficiencies in heating and cooling equipment is projected to increase at higher rates than market shares; therefore, over the long term, the total amount of heating- and cooling-related load is expected to decline slightly.

The forecast includes the impacts of existing and future DSM and energy efficiency programs. Impacts of existing programs are captured indirectly through the historical energy consumption data used in developing the forecasting models. The impacts of new programs and growth in existing programs are computed and captured in the load forecast as post-modeling adjustments. DSM and energy efficiency programs are projected to reduce peak demand and energy consumption by 14 MW and 48,251 MWH by 2028.

The large industrial class customers represent approximately one-third of total system energy consumption and one-fourth of total system peak demand requirements. Energy and peak projections for this class include only those customers that are currently being served. [redacted].[11]

The key economic and demographic assumptions upon which the load forecast is based are discussed in Section 4.6.3.

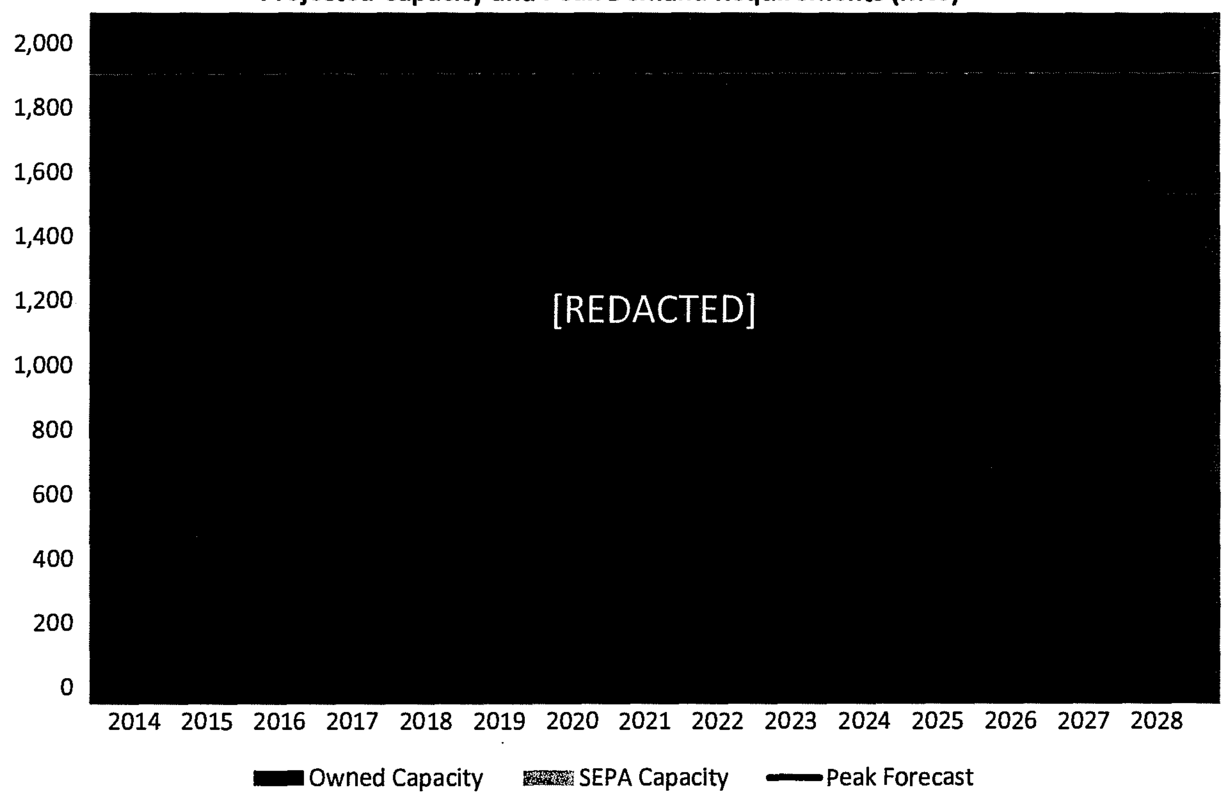
[10] The 2013 Load Forecast assumed 20 large industrial customers; however, there are currently 21 large industrial customers on the Big Rivers system. One of the 21 large industrials was expected to remove service after operations were shut down; however, it chose to maintain service at the site at a de minimis level of capacity and energy.

[11] Historically, due to the unpredictability of economic development successes and the significant increase in load resulting from the addition of new customers, Big Rivers' projections of energy and peak demand for the large industrial class reflect the base historical year values adjusted for known and measureable changes in consumption for existing customers, and new growth corresponding to potential customers that have a high likelihood of being served in future years.

1.6 Planned Resource Acquisitions

Big Rivers has no need for new capacity through 2028 to maintain an adequate reserve margin. In addition to existing capacity, Big Rivers has access to the wholesale power markets to buy and sell energy to maximize Member value and meet fluctuations in owned generation resource availability.

Figure 1.5
Projected Capacity and Peak Demand Requirements (MW)



Owned Capacity includes 312 MW of contract capacity from HMP&L
SEPA Capacity includes 178 MW of Big Rivers capacity and 12 MW of HMP&L capacity

Table 1.4
Projected Capacity and Peak Demand Requirements (MW)

Year	System Peak Demand (MW)	DSM Programs (MW)	Owned Capacity (MW)	SEPA Contract Maximum Capacity (MW)	Total Capacity (MW)	Capacity Surplus (MW)
2013	772					
2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[1] System peak demand represents the sum of rural system coincident peak demand plus all non-rural demand, plus transmission losses

[2] Total energy requirements include transmission losses

[3] Owned capacity values include resource capacity and energy from HMP&L Station Two that is available to serve Big Rivers' needs

[4] SEPA capacity is firm

For the development of the base case plan, as well as for sensitivity cases, a list of potential resource additions was developed for the resource assessment modeling process. This list of resources defines the options that the resource assessment model is able to choose in order to meet planning reserve criteria. The list of potential additions includes traditional supply-side options, renewable supply-side options, and energy efficiency programs that were selected in the DSM screening process. Big Rivers' resource assessment was developed using the Strategist Integrated Planning System, a Ventyx product, which is discussed in Section 9. The complete list of resource options is discussed in Sections 9 and 10.

Operating characteristics and associated costs for supply-side resources listed above were taken from the Energy Information Administration's ("EIA") 2014 Annual Energy Outlook[12] with modifications to certain variables based on GDS' involvement in recent generation feasibility analyses and construction monitoring. Tables in Section 9 contain cost and operational characteristics associated with potential supply-side options.

Big Rivers has worked diligently to improve operating efficiencies in its generating fleet since regaining control of its units in 2009. Base load unit heat rate has improved 420 BTU/kWh or 3.8% in the 4-year period from 2009 to 2013. Refer to Section 9.1 for further details regarding improvements in operating efficiency.

1.7 Key Issues or Uncertainties

Uncertainties in several key variables were addressed using a sensitivity case approach. In addition to the Base Case, cases were developed that factored in:

1. Fuel Price Sensitivity,
2. Energy Market Price Sensitivity,
3. Capacity Market Price Sensitivity,
4. Load Sensitivity (Weather),
5. Load Sensitivity (Economics),
6. Replacement Load Sensitivity,
7. Carbon Tax Sensitivity,
8. Renewable Portfolio Standard Sensitivity, and
9. Environmental Compliance Sensitivity.

Table 10.4 contains expansion plans associated with the sensitivity cases and demonstrates the changes in timing and resource types associated with resource additions.

1.8 Three-Year Action Plan

No generating resource acquisition steps are necessary over the next 3 years of the IRP, and no additional resources are required to maintain adequate reliability throughout the planning horizon under base case assumptions. Please see Section 12 for more details on Big Rivers' Action Plan.

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[12] http://www.eia.gov/analysis/projection-data.cfm#annualproj

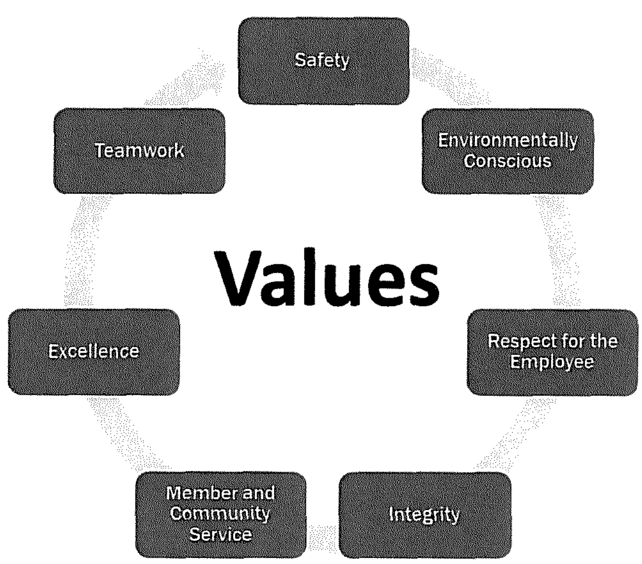
2. Planning Process

Big Rivers has a robust strategic planning process and works to incorporate corporate strategic planning initiatives into all planning processes. In preparation of the Resource Assessment required by this IRP, Big Rivers updated its load forecast, financial forecast, and DSM study. Additionally, Big Rivers incorporated the recommendations made by the Commission Staff in its report on Big Rivers' 2010 IRP. Appendix C of this IRP provides a cross-reference of those Commission Staff recommendations and this 2014 IRP. The results from these studies and Staff recommendations provided the inputs required to model the Big Rivers' system with respect to the integration of existing and future capacity resources.

2.1 Big Rivers' Strategic Plan

Despite the smelter contract terminations, which had a significant impact on Big Rivers' revenues and resource plans, Big Rivers' mission remains unchanged: to safely deliver low-cost, reliable wholesale power and the cost-effective shared services desired by our Members. Big Rivers' strategic objectives are as follows:

- Meet our Members' reliability needs and regulatory compliance requirements in the most cost-effective manner,
- Provide cost-effective shared services desired by our Members,
- Proactively manage assets for the benefit of all Members,
- Maintain a comprehensive and least-cost environmental compliance strategy,
- Considering risks and benefits, manage the volatility of rates to Members and Big Rivers' net margin,
- Meet key financial forecast metrics and maintain at least two investment grade credit ratings of BBB- or Baa3 or higher,
- Continue Big Rivers' emphasis on safety for employees, Members, contractors, and the public,
- Maintain a well-trained, engaged workforce dedicated to teamwork and the success of Big Rivers and its Members, and
- Proactively enhance Big Rivers' reputation and maintain and/or build trust with key stakeholders.



Big Rivers continues to implement its plan to mitigate the loss of smelter load. Through a focused approach on maximizing Member value and maintaining long-term financial viability, Big Rivers continues to aggressively pursue its mission – providing the services to its Members for which it was created.

2.2 Load Forecast

The load forecast used for this analysis (the "2013 Load Forecast") was completed in April 2013, and was subsequently approved by Big Rivers' Board of Directors in April 2013, and by the U. S. Department of Agriculture's Rural Utilities Service ("RUS") in June 2013. Additional sensitivities to the 2013 Load Forecast were developed and included in this IRP process.

The forecast is developed using a "bottom-up" approach, as forecasts are developed individually for each of Big Rivers' three Member distribution cooperatives and aggregated to the Big Rivers level. Preliminary forecasts are presented to each of the Members for review and revisions prior to development of the final Big Rivers forecast. Review meetings are held in person and via webinars.

The forecast is developed using both quantitative and qualitative methods. A series of econometric models are used to forecast energy consumption and peak demand for rural system customers. Projections for 20 large industrial customers are based on historical consumption and peak demand, combined with information received from the management of Big Rivers' Members regarding future plans and operations.

Big Rivers continues to review its load forecasting process and make enhancements as new information and technologies become available. Big Rivers and GDS will continue to monitor industry advancements and best practices to continue to enhance future forecast accuracy.

See Section 4 for further details of the 2013 Load Forecast.

2.3 Demand-Side Management[13] Study

DSM measure lists were developed in an effort to address different customer classifications and end-use types. The measure list was restricted to DSM measures and practices that are currently commercially available. These are measures that are of most immediate interest to program planners.[14]

Significant detail is needed to estimate the average and total savings potential for individual measures or programs. Estimates of annual measure savings, costs, and useful lives were developed using various technical reference manuals ("TRM"), energy modeling software ("REM/Rate"), energy calculations, evaluation reports, and other secondary sources[15]. Program participation rates were developed using

[13] In the context of Big Rivers' IRP, demand-side management is defined as all activities designed to impact electricity use, including demand- response and energy efficiency programs.

[14] About 100 individual measures were analyzed in the DSM portion of the IRP. After accounting for adjustments for different building types, housing characteristics and measures targeting space heating and cooling end-use, the number grew to exceed 200 measure permutations.

[15] TRMs: GDS relied primarily on the Indiana Technical Resource Manual, which was provided directly to GDS by the Indiana Utility Regulatory Commission. GDS also utilized the Mid-Atlantic Technical Reference Manual: http://www.neep.org/Assets/uploads/files/emv/emv-products/TRM_March2013Version.pdf.

various data sources including building characteristic data from current Big Rivers' appliance saturation studies, EIA regional data [16], and budgeting parameters, such as the level of incentives to be paid to retail Members for installing energy efficiency measures through Big Rivers' DSM programs.

Big Rivers evaluates the cost-effectiveness of specific DSM measures when determining which DSM programs to implement. The net present value of costs vs. benefits is assessed, i.e., the costs to implement the measures are valued against the savings or avoided costs. The resultant benefit/cost ratios, or tests, provide a summary of the measure's cost-effectiveness relative to the benefits of its projected load impacts. Measures were screened using the GDS Benefit/Cost Screening Model, which is an analysis tool designed to evaluate the costs, benefits, and risks of DSM programs and services.

The main criterion Big Rivers used to screen DSM measures was the Total Resource Cost ("TRC") test. The TRC test measures the net costs of an energy measure or program as a resource option based on the total costs of the program, including both the participant's and the utility's costs (the "typical" California tests)[17]. The benefits include the avoided electric supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at the marginal cost for the period when there is an electric load reduction, and the savings of other resources such as fossil fuels and water. All equipment costs, installation, operation and maintenance, tax credits, cost of removal, and administration costs[18] are included in this test. Results are typically expressed as either net benefits or benefit-to-cost ratio.

The analysis performed to prepare this IRP represents the 2014-2028 timeframe, although the primary analytical focus for DSM programs is the first three years. This technique was used to concentrate on the near-term, while recognizing that course corrections due to evolving markets, technologies and regulations may be made along the way. A complete list of the DSM programs, their annual impacts and long-term savings potential are presented in greater detail in Section 5 of this IRP and in the DSM Potential Study provided in Appendix B.

2.4 Resource Assessment

Big Rivers' resource assessment is developed using the Strategist Integrated Planning System. This model, which is licensed to GDS by Ventyx, has the capability to simulate production operations and

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REM/Rate: According to the Architectural Energy Corporation, "REM/Rate™ is a user-friendly, yet highly sophisticated, residential energy analysis, code compliance and rating software developed specifically for the needs of HERS providers," http://www.archenergy.com/products/remrate.

Energy Calculations: In some cases GDS performed independent energy savings calculations using a variety of source data. GDS also relied on the various ENERGY STAR savings calculators that are provided on the ENERGY STAR Energy Efficient Products webpages: http://www.energystar.gov/certified-products/certified-products?c=products.pr_find_es_products. The DSM potential study provided in Appendix B provides a full listing of all energy savings assumptions and sources.

[16] http://www.eia.gov/consumption/commercial/data/2003/index.cfm?view=characteristics

[17] http://www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf

[18] Administrative costs were included in the evaluation of the cost-effectiveness of the portfolio of programs. These costs were not included in the measure-level screening of specific technologies. This approach aligns with the EPA Guide for Conducting Energy Efficiency Potential Studies (November 2007). http://www.epa.gov/cleanenergy/documents/suca/potential_guide.pdf

develop least cost expansion plans. The production operations simulation establishes the optimal dispatch of generating resources and calculates the associated costs. The development of least cost expansion plans includes comparisons of all combinations of potential resource additions to determine the portfolio of expansion units necessary to achieve planning reserve margin criteria at the lowest cost. Big Rivers' existing generating resources are modeled using the Strategist Generation and Fuel module ("GAF"). The existing units are dispatched against the 2013 Load Forecast, which is described in Section 4. The 2013 Load Forecast is modeled using the Strategist Load Forecast Adjustment module ("LFA"). To address uncertainties related to multiple variables, the production simulation and expansion planning analysis is used to develop a base case and a number of sensitivity cases. The base case includes (1) the base load forecast, (2) the energy efficiency ("EE") programs included in the $1 million annual energy efficiency expenditure case, (3) base fuel price projections, and (4) base market price projections as a source of economy energy purchases. In addition to the base case, 17 sensitivity cases were developed, all of which are discussed in greater detail in Section 9.

Refer to Section 4.7 for further discussion of the alternative load forecast scenarios and Section 12 for discussion of the action plan.

3. Changes since the 2010 IRP

Big Rivers' 2010 IRP was filed with the Commission on November 15, 2010, and was assigned Case No. 2010-00443.

In December 2010, pursuant to the approval received in Case No. 2010-00043[19], Big Rivers became a transmission-owning member of MISO and placed its transmission and generating assets under MISO's functional control. Big Rivers participates in MISO's coordinated long-term and short-term planning processes, including compliance with MISO tariff Module E-1 for Resource Adequacy.[20] MISO tariff Module E-1 Section 68 up to, but not including, Section 70 and MISO's Business Practice Manual for Resource Adequacy ensure there are adequate planning resources available to enable load serving entities to reliably serve Load. See Section 7 for more details on MISO's planning process.

On August 20, 2012, Century Aluminum of Kentucky General Partnership ("Century") gave notice terminating its retail power contract for its aluminum smelter in Hawesville, Kentucky ("Century Hawesville"), effective August 20, 2013. In response to that notice, Big Rivers began implementing a plan it had developed to address the potential loss of one or both of the aluminum smelters on the Big Rivers system (the "Mitigation Plan"). The Mitigation Plan calls for Big Rivers to immediately begin

(i) preparing a rate case to address revenue associated with the loss of a smelter;

(ii) marketing all available power when the market price is greater than marginal generation cost, either through increased off-system sales or by acquiring replacement load;

(iii) reducing costs and scaling back operations, including temporarily idling generating units when the price of power does not support the cost of generating; and

(iv) exploring the possibility of selling or leasing generating units.

On December 17, 2012, Big Rivers sent the Commission a letter requesting that the filing date for its next IRP be postponed from November 15, 2013, to November 15, 2014, to allow Big Rivers time to pursue the Mitigation Plan and to achieve more certainty around its load and resources. On January 29, 2013, the Commission issued an order in Case No. 2013-00034 granting Big Rivers a six-month extension until May 15, 2014, to file this IRP.

Big Rivers filed a rate case to address the loss of the Century Hawesville load and other revenue shortfalls on January 15, 2013. That case was assigned Case No. 2012-00535.[21] Shortly thereafter, on January 31, 2013, Alcan Primary Products Corporation ("Alcan") gave notice terminating the retail power contract for its aluminum smelter in Sebree, Kentucky, which was later purchased by Century (the "Century Sebree" smelter). The termination of the retail power contract for Century Sebree was

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[19] *In the Matter of: Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of its Transmission System to Midwest Independent Transmission System Operator, Inc.*, Case No. 201 0-00043. Subsequent to this proceeding, MISO changed its name from Midwest Independent Transmission System Operator, Inc., to Midcontinent Independent System Operator, Inc.

[20] Available at MISO's website: https://www.misoenergy.org/Pages/Home.aspx

[21] *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Case No. 2012-00535.

effective January 31, 2014. In response to the Century Sebree contract termination, Big Rivers filed a second rate case (Case No. 2013-00199[22]) on June 28, 2013, and continued its efforts to mitigate the impacts of the smelter contract terminations. Due to the short timeframe since issuance of the order in Case No. 2013-0199 on April 25, 2014, analysis for the preparation of this IRP includes the rates proposed in that case.

In an effort to allow Century Hawesville and Century Sebree to continue operating and to preserve the nearly 1,200 direct jobs and other economic benefits at those facilities, Big Rivers, Kenergy (which is the retail electric supplier to the smelters), and Century, entered into agreements that would allow the smelters to continue to operate by allowing them to purchase energy at market-based rates, without imposing any additional costs on Big Rivers or the remaining retail ratepayers served from the Big Rivers' system than would have been necessary had the smelters closed. The Commission approved those agreements in Case Nos. 2013-00221[23] and 2013-00413.[24]

When it filed Case No. 2012-00535, and because of the depressed power market at that time, Big Rivers anticipated substantially reducing its expenses by temporarily idling one generating station on August 20, 2013, until Big Rivers secured replacement load or until the wholesale power market improved sufficient to justify returning that plant to service. When it filed Case No. 2013-00199, Big Rivers anticipated further reducing its expenses by temporarily idling a second generating station on January 31, 2014, until Big Rivers secured replacement load or until the wholesale power market improved sufficient to justify returning that plant to service. The strategy to idle the Kenneth C. Coleman and D. B. Wilson generating stations was an integral part of the Plan.

At this time, Big Rivers has idled, or is in the process of idling, the Coleman Station. As Big Rivers is a member of MISO, Big Rivers filed an Attachment Y notification with MISO prior to idling a generation resource, and participated in studies to determine whether the Coleman Station was needed for reliability with Century Hawesville operating. As a result, Coleman Station was designated a System Support Resource ("SSR"), and Big Rivers was reimbursed for all costs of operating Coleman Station as an SSR. Century has installed equipment and secured MISO and SERC approval that allowed Big Rivers to idle Coleman Station on April 30, 2014 even with Century Hawesville operating.

With regard to the Wilson Station, the Mitigation Plan calls for Big Rivers to mitigate the rate increases required as a result of the smelter contract terminations by increasing off-system sales or finding replacement load. Due to recent , favorable conditions in the wholesale power market, Big Rivers has made forward power sales from Wilson that has enabled Big Rivers to postpone the idling of the Wilson Station until February 2015 and possibly beyond.

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[22] *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Case No. 2013-00199.

[23] *In the Matter of: Joint Application of Kenergy Corp. and Big Rivers Electric Corporation for the Approval of Contracts and for a Declaratory Order*, Case No. 2013-00221.

[24] *In the Matter of: Joint Application of Kenergy Corp. and Big Rivers Electric Corporation for the Approval of Contracts and for a Declaratory Order*, Case No. 2013-00413.

In addition to those power sales from Wilson, Big Rivers has begun to have success in acquiring replacement load. Replacement load, as further discussed in Section 4.2.4, is expected to take many forms, including both economic development efforts and entering into bilateral contracts with counterparties inside and outside of Kentucky. Since the end of October 2013, Big Rivers has successfully secured 92 MW of replacement load, including an agreement with a Nebraska consortium for 67 MW of replacement load beginning in 2018 and 25 MW of growth in native load due to new customer additions. Although the replacement load is not yet sufficient to further postpone idling the Coleman generating station, Big Rivers continues to seek additional replacement load, and is actively negotiating potential arrangements with other businesses, including other Kentucky-based utilities and multiple out-of-state prospects. Big Rivers also continues to pursue the possibility of selling or leasing one or more generating units.

The loss of the smelter loads, the idling of the Coleman and/or Wilson Stations, and implementation of the Mitigation Plan are the most significant changes in Big Rivers' resource planning since Big Rivers filed the 2010 IRP. In addition, Big Rivers has performed a reserve margin study, updated its load forecast, and updated its DSM analysis.

As a result of the smelter contract terminations, Big Rivers' power supply requirements were reduced by approximately 850 MW and 7,300 GWh per year. Replacement load already secured by Big Rivers is expected to increase power supply requirements by at least 92 MW by 2022.

3.1 Changes to the Load Forecast

3.1.1 Load Forecasting Methodology

Since the 2010 IRP, Big Rivers has updated portions of its load forecast methodology. Previously, projections of Members' contributions to Big Rivers' rural system peak demand were based on projections of rural system energy requirements and assumed load factors. For the 2013 Load Forecast, an econometric model was developed to project Big Rivers' rural system peak, by month, and aggregated based on the Members' coincidence factors developed for each cooperative. The econometric model was used to develop projections in 2013-2017. Projections for 2018-2028 were based on the energy forecast and the average load factor derived for years 2013-2017 from the energy and peak demand econometric models.

3.1.2 Updated Energy and Peak Demand Forecast

Since filing the 2010 IRP, Big Rivers has commissioned GDS to prepare two formal load forecasts, and Big Rivers updates its internal load forecast on a more frequent basis to meet MISO forecasting requirements and internal planning needs. Figures 3.1 through 3.3 present projected native system requirements from the 2010 IRP, the 2011 Load Forecast, and the 2013 Load Forecast. The 2013 Load Forecast was used in development of the 2014 IRP; however, as part of this IRP planning process, a number of sensitivities were performed to provide further analysis and insights to customer consumption possibilities in the future. Energy and peak demand requirements represent Big Rivers' native system load and exclude smelter and HMP&L requirements.

The growth rate in number of customers has fallen slightly with each new forecast, due to the lower trend in historical growth and the lower outlooks in the number of projected households.

The forecast of total energy requirements was lowered in both the 2011 and 2013 forecasts. Total energy is a function of number of customers and energy use per customer, and both components were lowered in both forecasts. Average energy consumption has leveled in recent years due primarily to increases in appliance efficiencies and energy conservation. Furthermore, the 2013 forecast reflects price increases in 2014-2016 that cause average use per residential and small commercial customer to decline slightly.

Consistent with the lowering of the energy forecasts in the 2011 and 2013 studies, the projections of peak demand were also lowered. The impacts of new energy efficiency programs are reflected in the 2011 and 2013 forecasts.

Table 3.1
Comparison of Projected Number of Customers

	Actual	*2010 IRP*	*2011 Load Forecast*	*2013 Load Forecast*
2002	*103,482*			
2003	*104,764*			
2004	*106,414*			
2005	*107,883*			
2006	*109,329*			
2007	*110,585*			
2008	*111,693*			
2009	*111,923*	*112,492*		
2010	*112,391*	*113,497*		
2011	*112,888*	*114,870*	*112,972*	
2012	*113,252*	*116,410*	*113,995*	
2013		*117,975*	*115,512*	*113,584*
2014		*119,519*	[redacted]	[redacted]
2015		*121,046*	[redacted]	[redacted]
2016		*122,559*	[redacted]	[redacted]
2017		*124,064*	[redacted]	[redacted]
2018		*125,574*	[redacted]	[redacted]
2019		*127,088*	[redacted]	[redacted]
2020		*128,596*	[redacted]	[redacted]
2021		*130,081*	[redacted]	[redacted]
2022		*131,521*	[redacted]	[redacted]
2023		*132,906*	[redacted]	[redacted]
2024			[redacted]	[redacted]
2025			[redacted]	[redacted]
2026				[redacted]
2027				[redacted]
2028				[redacted]

Figure 3.1
Number of Customers

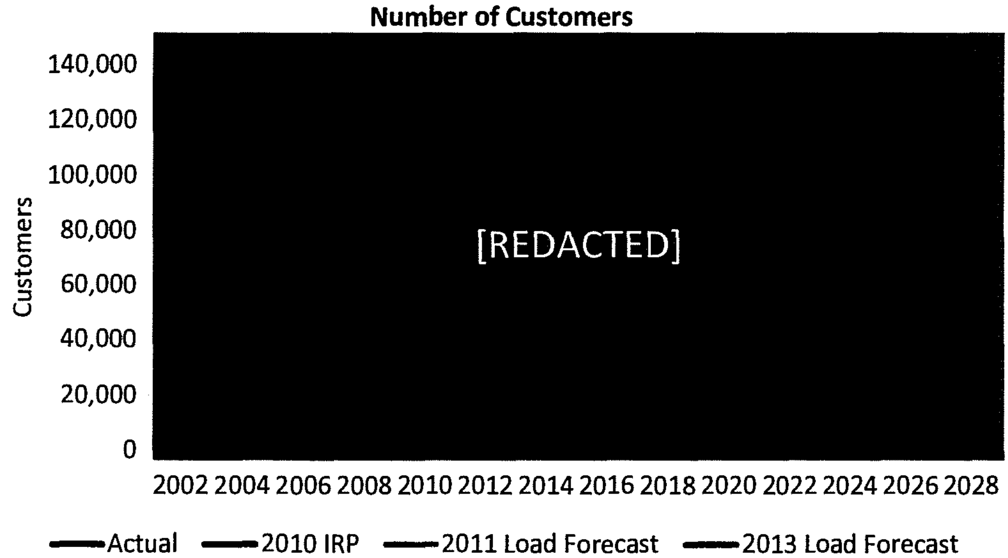


Table 3.2
Comparison of Projected Native Energy Requirements (GWh)

	Actual	*Weather Adjusted*	*2010 IRP*	*2011 Load Forecast*	*2013 Load Forecast*
2002	*3,233*	*3,174*			
2003	*3,088*	*3,148*			
2004	*3,159*	*3,219*			
2005	*3,260*	*3,251*			
2006	*3,214*	*3,281*			
2007	*3,353*	*3,288*			
2008	*3,340*	*3,323*			
2009	*3,231*	*3,277*	*3,371*		
2010	*3,474*	*3,346*	*3,403*		
2011	*3,377*	*3,369*	*3,437*	*3,355*	
2012	*3,320*	*3,320*	*3,472*	*3,366*	
2013			*3,503*	*3,398*	*3,346*
2014			*3,539*	[redacted]	[redacted]
2015			*3,579*	[redacted]	[redacted]
2016			*3,619*	[redacted]	[redacted]
2017			*3,666*	[redacted]	[redacted]
2018			*3,712*	[redacted]	[redacted]
2019			*3,758*	[redacted]	[redacted]
2020			*3,799*	[redacted]	[redacted]
2021			*3,846*	[redacted]	[redacted]
2022			*3,892*	[redacted]	[redacted]
2023			*3,936*	[redacted]	[redacted]
2024				[redacted]	[redacted]
2025				[redacted]	[redacted]
2026					[redacted]
2027					[redacted]
2028					[redacted]

Figure 3.2
Energy Requirements

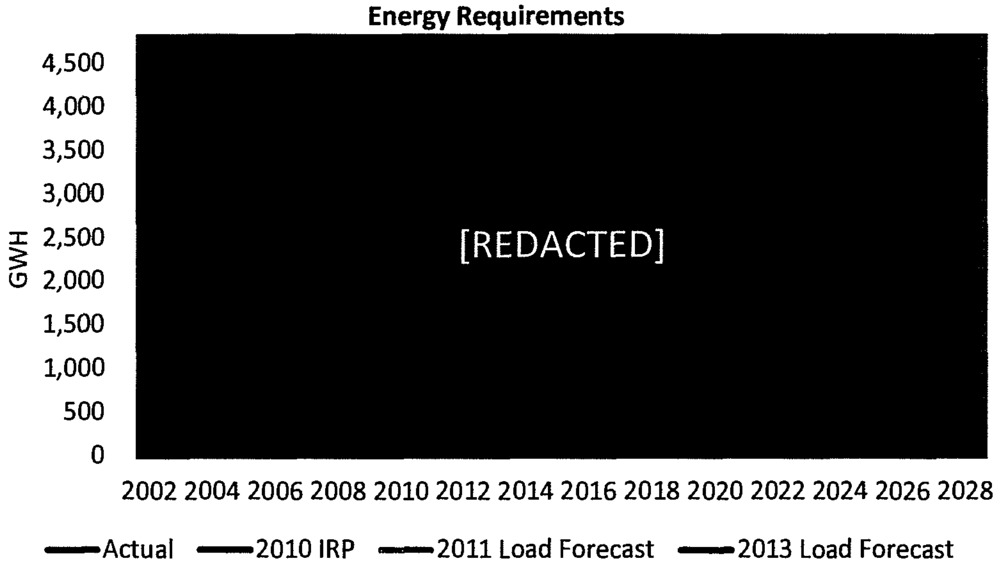
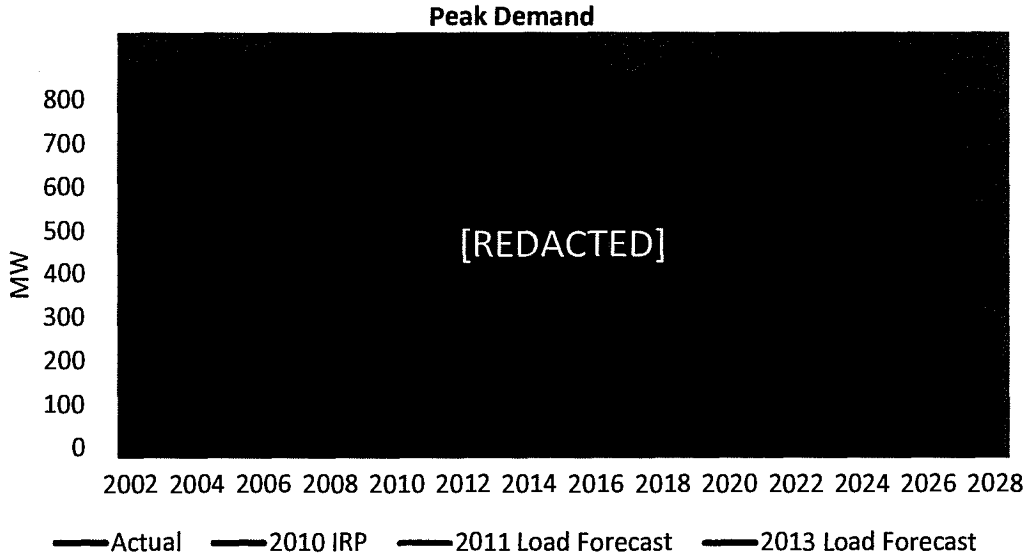


Table 3.3
Comparison of Projected Native Peak Demand (MW)

	Actual	*Weather Adjusted*	*2010 IRP*	*2011 Load Forecast*	*2013 Load Forecast*
2002	*595*				
2003	*578*				
2004	*599*	*632*			
2005	*613*	*618*			
2006	*626*	*647*			
2007	*654*	*625*			
2008	*614*	*629*			
2009	*668*	*642*	*637*		
2010	*657*	*645*	*641*		
2011	*652*	*650*	*648*	*648*	
2012	*654*	*630*	*655*	*650*	
2013			*661*	*656*	*632*
2014			*668*	[redacted]	[redacted]
2015			*676*	[redacted]	[redacted]
2016			*684*	[redacted]	[redacted]
2017			*693*	[redacted]	[redacted]
2018			*702*	[redacted]	[redacted]
2019			*711*	[redacted]	[redacted]
2020			*719*	[redacted]	[redacted]
2021			*728*	[redacted]	[redacted]
2022			*737*	[redacted]	[redacted]
2023			*746*	[redacted]	[redacted]
2024				[redacted]	[redacted]
2025				[redacted]	[redacted]
2026					[redacted]
2027					[redacted]
2028					[redacted]

Figure 3.3
Peak Demand



3.2 Updates to Demand-Side Management Programs

Big Rivers has taken a proactive approach to advance Strategy 1 of the 2008 Governor's Intelligent Energy Choices plan "to improve the efficiency of Kentucky's homes, buildings, industries and transportation fleet by establishing a goal of offsetting at least 18 percent of Kentucky's projected 2025 energy demand."[25]

The 2010 IRP included a DSM Potential Study, which provided an analysis of potential DSM, energy efficiency, and demand response programs. Since the 2010 IRP, Big Rivers has implemented a number of DSM and energy efficiency programs that were determined to be cost effective. The methodology for screening DSM programs currently is the same methodology used in the 2010 IRP.

Prior to the issuance of the Commission Staff's report on the 2010 IRP, Big Rivers filed a general rate application on March 1, 2011. That application was assigned Case No. 2011-00036.[26] In that application, Big Rivers proposed annual DSM and energy efficiency program funding of $1.0 million for a period of five years. In its orders dated November 17, 2011, and January 29, 2013, in that proceeding, the Commission approved Big Rivers' DSM/EE funding proposal and directed Big Rivers to file semi-annual reports on the status of its DSM/EE programs. Big Rivers has filed such reports on January 31, 2012, July 31, 2012, January 31, 2013, July 31, 2013, and January 31, 2014.

In response to a letter dated November 29, 2011, from the Commission's Executive Director, Big Rivers filed tariff sheets for each of its ten (10) DSM/EE programs on March 16, 2012. The Commission opened Case No. 2012-00142[27] to review these programs. The Commission allowed these programs to go into effect subject to change, and issued its order approving them on August 22, 2012. On February 22, 2013, Big Rivers filed tariffs to revise and expand its DSM/EE programs (Case No. 2013-00099[28]). Big Rivers' revisions primarily addressed additional incentives for interested customers to participate in these programs. Big Rivers' expansion also included two new programs – a commercial program for high-efficiency heating, ventilation, and air-conditioning equipment, and a high-efficiency outdoor lighting program. On March 21, 2013, the Commission issued its order approving the proposed changes to seven (7) of the previously approved programs, and opening an investigation into the other programs. On June 6, 2013, the Commission issued its order approving the proposed changes to the three (3) other original programs, and approving the two (2) additional programs. Big Rivers continues to work with its Members to implement and monitor the performance of these DSM/EE programs. Much of this work is done through a DSM/EE Working Group consisting of Big Rivers', and its Members' employees, which meets monthly. Further discussion of DSM is provided in Section 5 and in the DSM Potential Study in Appendix B of this IRP.

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[25] *See http://energy.ky.gov/Documents/Final_Energy_Strategy.pdf.*

[26] *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Case No. 2011-00036.

[27] *In the Matter of: Tariff Filing of Big Rivers Electric Corporation to Implement Demand-Side Management Programs*, Case No. 2012-00142.

[28] *In the Matter of: Tariff Filing of Big Rivers Electric Corporation to Revise and Implement Demand-Side Management Programs*, Case No. 2013-00099.

3.3 Updates to the Transmission System

With respect to the improvement and more efficient utilization of Big Rivers' existing transmission facilities, since the 2010 IRP was filed, Big Rivers constructed new transmission lines to strengthen the subtransmission network and to serve our Members' new delivery point substations. Big Rivers also reconductored sections of 69kV and 161kV lines and energized a new 345kV interconnection to improve power transfer both on and off the Big Rivers' transmission system. Big Rivers is working through the phases to loop an existing Big Rivers-owned circuit to result in a second Big Rivers 161kV interconnect to the KU Matanzas substation. Big Rivers also upgraded microwave communications infrastructure and completed the replacement of the two-way radio system of Big Rivers and its three Members. Each company now operates its own two-way radio system. These new systems share a common backbone infrastructure and accommodate two-way radio communications among the four companies during emergency situations. See Section 6 for more details on these activities.

3.4 Changes in Resource Assessment

As mention earlier in this section, two aluminum smelters terminated their retail power contracts effective in 2013 and 2014, reducing peak demand by approximately 850 MW. While the 2010 IRP reflected a need for new capacity under the base case beginning in 2022, the current IRP reflects no additional need for capacity under the base case at any point during the next 15 years.

The methodology and modeling process used in development of the 2014 IRP remains the same as the 2010 IRP; however, additional planning scenarios have been developed during the 2014 IRP process to provide a more robust modeling and planning effort. Please refer to Section 9 for details.

4. Load Forecast

The 2014 IRP is based on Big Rivers' 2013 Load Forecast base case; however, a number of sensitivities were completed in the IRP planning process. The load forecast is generally updated every two years by GDS; however, Big Rivers makes updates as needed for planning purposes.[29] The 2013 Load Forecast was completed in April 2013 and approved by Big Rivers' Board of Directors. The most recent historical year included in the 2013 Load Forecast is 2012, and the base forecast year for both that load forecast and this IRP is 2013. The forecast horizon covers years 2013 through 2028.

4.1 Total System Forecast

Total system energy and peak demand requirements are projected to reach [redacted] GWH and [redacted] MW by 2028. Total system requirements include native system, replacement, and HMP&L load. Refer to Section 4.2.4 below for a discussion of replacement load, which is defined as current and future sales corresponding to approximately 800 MW of capacity available to Big Rivers following the smelter contract terminations. Total system load factor is currently running just under 60 percent and is expected to increase to 66 percent by 2021, when the full 800 MW of replacement load is under contract.

Native system energy and peak demand requirements (total load excluding replacement and HMP&L requirements) are projected to [redacted] at average compound rates of [redacted]% and [redacted]%, respectively, per year from 2013 through 2028. Native energy requirements are projected to [redacted] in 2015 and 2016 in response to projected retail price increases. Native peak demand is projected to [redacted] by approximately [redacted] MW per year from 2013 through 2028. Replacement load enters the forecast in 2016 at 103 MW at 75% load factor, and increases to 827 MW (with losses) at the same load factor by 2021. Tables 4.1 and 4.2 present projected total system energy and peak demand requirements. Tables 4.3 and 4.4 present monthly projections of energy requirements and peak demand for the first two years of the forecast.

A review of the 2013 Load Forecast was completed during February 2014, which included an analysis and comparison of energy and peak demand projections for 2013 to actual values for the year. Actual 2013 energy and peak demand values were weather adjusted to provide for a comparison of data on the same basis (projections reflect normal weather). The energy requirements forecast variance (forecast v. actual) for 2013 was 0.6 percent, the winter peak variance was 1.6 percent, and the summer peak variance was 1.2 percent. The 2013 Load Forecast was not updated prior to its use in development of this IRP, as no material changes warranted adjustment; however, a number of additional sensitivities were prepared during the IRP process. See Section 10 for a listing of the sensitivities.

[29] Big Rivers secures financing from RUS. RUS requires Big Rivers to update its load forecast every two years and to submit the forecast to RUS for review and approval. RUS approved the 2013 Load Forecast on June 26, 2013.

Table 4.1
Historical and Projected Energy Requirements

	Member Coop Retail Sales (MWH)	*Distribution Losses (%)*	*Big Rivers Energy Sales (MWH)*	*Replacement Load (MWH)*	*G&T Losses (MWH)*	*HMP&L (MWH)*	*Total Energy Requirements (MWH)*
2009	*3,092,391*	*3.5%*	*3,206,088*		*109,411*	*591,442*	*3,906,942*
2010	*3,317,423*	*3.7%*	*3,445,715*		*117,589*	*646,412*	*4,209,716*
2011	*3,279,929*	*3.1%*	*3,385,501*		*115,534*	*622,398*	*4,123,434*
2012	*3,367,558*	*3.5%*	*3,488,924*		*119,064*	*618,841*	*4,226,829*
2013	*3,186,069*	*3.5%*	*3,300,904*		*112,647*	*626,559*	*4,040,110*
2014	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	*658,800*	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	*1,314,000*	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	*1,971,000*	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	*2,628,000*	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	*3,952,800*	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	*5,256,000*	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	*5,256,000*	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	*5,256,000*	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	*5,270,400*	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	*5,256,000*	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	*5,256,000*	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	*5,256,000*	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	*5,270,400*	[redacted]	[redacted]	[redacted]

Shaded year represents base year

Transmission losses adjusted in 2009-2013 to reflect the exclusion of smelter load impacts

HMP&L based on HMP&L load forecast

Values are net of DSM

Table 4.2
Historical and Projected Peak Demand

	Rural System (MW)	*Direct Serve (MW)*	*Native System (MW)*	*Replacement Load (MW)*	*G&T Losses (MW)*	*HMP&L (MW)*	*Total Peak Demand (MW)*
2009	561	107	668		23	111	801
2010	540	117	657		22	117	797
2011	533	119	652		22	113	787
2012	542	89	630		22	115	767
2013	510	123	633		22	117	772
2014	511	126	637		21	117	775
2015	512	126	638		22	118	777
2016	516	125	641	100	25	118	884
2017	522	125	647	200	29	118	994
2018	526	125	651	300	32	119	1,102
2019	531	125	656	400	36	119	1,211
2020	536	125	661	600	43	120	1,423
2021	541	125	666	800	50	120	1,636
2022	547	125	672	800	50	120	1,642
2023	552	125	678	800	50	121	1,649
2024	558	125	683	800	50	121	1,655
2025	564	125	689	800	51	121	1,661
2026	570	125	695	800	51	122	1,668
2027	576	125	702	800	51	122	1,674
2028	583	125	708	800	51	122	1,682

Shaded year represents base year

Transmission losses adjusted in 2009 -2013 to reflect the exclusion of smelter load impacts

HMP&L based on HMP&L load forecast

Values are net of DSM

Table 4.3
Monthly Energy Sales by Sector and Total Generation

Year	*Month*	*Rural Energy Requirements (MWH)*	*Direct Serve Energy Requirements (MWH)*	*Generation & Transmission Losses (MWH)*	*HMP&L (MWH)*	*Total System Energy Requirements (MWH)*
2014	*1*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*2*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*3*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*4*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*5*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*6*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*7*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*8*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*9*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*10*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*11*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*12*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*1*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*2*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*3*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*4*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*5*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*6*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*7*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*8*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*9*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*10*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*11*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*12*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Values are net of DSM

Table 4.4
Monthly Peak Demand by Sector and Total System

Year	*Month*	*Rural Demand Requirements (MW)*	*Direct Serve Demand Requirements (MW)*	*Generation & Transmission Losses (MW)*	*HMP&L (MW)*	*Total System Demand Requirements (MW)*
2014	*1*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*2*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*3*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*4*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*5*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*6*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*7*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*8*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*9*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*10*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*11*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	*12*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*1*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*2*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*3*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*4*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*5*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*6*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*7*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*8*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*9*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*10*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*11*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	*12*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Values are net of DSM

4.2 Customer Class Forecasts

This section presents historical and projected number of customers and energy sales by Member retail classification. All values are net of DSM.

4.2.1 Residential

Total residential sales for Big Rivers' three Members are projected to increase at an average rate of 0.7 percent per year from 2013 through 2028. Total sales from 2013-2016 are projected to decline as customers are expected to lower consumption due to price increases over the near term. Growth in sales is expected to average 1.1 percent per year beyond 2016. Growth in the number of customers, projected at 0.8 percent per year, is the primary influence on growth in total residential sales. Average use per customer is projected to be relatively flat over the forecast horizon, declining by 0.2 percent per year from 2013-2016 and then increasing at an average rate of 0.3 percent thereafter.

Table 4.5
Residential

	Number of Customers	Change per Yr.	% Change per Yr.	Energy Sales (MWH)	Normalized Energy Sales (MWH)	% Change per Yr.	Avg. kWh per Mo.	% Change per Yr.
2009	97,084			1,426,775	1,448,257		1,243	
2010	97,467	383	0.4%	1,611,212	1,520,749	5.0%	1,300	4.6%
2011	97,750	283	0.3%	1,530,090	1,524,366	0.2%	1,300	-0.1%
2012	97,675	(74)	-0.1%	1,465,749	1,466,082	-3.8%	1,251	-3.8%
2013	97,911	236	0.2%		1,492,078	1.8%	1,270	1.5%
2014	98,761	850	0.9%		1,476,266	-1.1%	1,246	-1.9%
2015	99,723	962	1.0%		1,456,291	-1.4%	1,217	-2.3%
2016	100,671	948	1.0%		1,449,745	-0.4%	1,200	-1.4%
2017	101,591	920	0.9%		1,464,578	1.0%	1,201	0.1%
2018	102,459	868	0.9%		1,478,045	0.9%	1,202	0.1%
2019	103,313	854	0.8%		1,492,474	1.0%	1,204	0.1%
2020	104,176	863	0.8%		1,507,739	1.0%	1,206	0.2%
2021	105,041	865	0.8%		1,524,147	1.1%	1,209	0.3%
2022	105,884	843	0.8%		1,541,192	1.1%	1,213	0.3%
2023	106,711	827	0.8%		1,558,220	1.1%	1,217	0.3%
2024	107,505	794	0.7%		1,575,230	1.1%	1,221	0.3%
2025	108,286	781	0.7%		1,592,793	1.1%	1,226	0.4%
2026	109,072	786	0.7%		1,610,814	1.1%	1,231	0.4%
2027	109,844	772	0.7%		1,629,146	1.1%	1,236	0.4%
2028	110,616	772	0.7%		1,647,478	1.1%	1,241	0.4%

4.2.2 Small Commercial & Industrial

Small commercial & industrial customers, referenced as Small C&I ("C&I") in Big Rivers' 2013 Load Forecast, is defined as all commercial and industrial customers that are not served under Big Rivers' LIC tariff. Small commercial sales for Big Rivers' three Members are projected to increase at an average rate of 0.7 percent per year from 2013 through 2028. Growth in the number of customers, projected at 0.8 percent per year, is the primary influence on growth in total sales. Additionally, growth in commercial customers and sales is a driver of growth in residential sales. Like the residential class, consumption per Small C&I customer is projected to be relatively flat, declining by 0.1 percent per year from 2013-2016 and then increasing at an average rate of 0.3 percent through 2028.

Table 4.6
Small Commercial & Industrial

	Number of Customers	*Change per Yr.*	*% Change per Yr.*	*Energy Sales (MWH)*	*Normalized Energy Sales (MWH)*	*% Change per Yr.*	*Avg. kWh per Mo.*	*% Change per Yr.*
2009	*14,745*			*709,468*	*716,629*		*4,050*	
2010	*14,828*	*83*	*0.6%*	*740,160*	*710,006*	*-0.9%*	*3,990*	*-1.5%*
2011	*15,022*	*194*	*1.3%*	*729,805*	*727,897*	*2.5%*	*4,038*	*1.2%*
2012	*15,458*	*436*	*2.9%*	*730,476*	*730,587*	*0.4%*	*3,939*	*-2.5%*
2013	*15,549*	*91*	*0.6%*		*731,306*	*0.1%*	*3,919*	*-0.5%*
2014	*15,680*	*131*	*0.8%*		*724,071*	*-1.0%*	*3,848*	*-1.8%*
2015	*15,830*	*150*	*1.0%*		*714,689*	*-1.3%*	*3,762*	*-2.2%*
2016	*15,977*	*147*	*0.9%*		*711,463*	*-0.5%*	*3,711*	*-1.4%*
2017	*16,119*	*142*	*0.9%*		*718,648*	*1.0%*	*3,715*	*0.1%*
2018	*16,253*	*135*	*0.8%*		*725,205*	*0.9%*	*3,718*	*0.1%*
2019	*16,376*	*123*	*0.8%*		*730,722*	*0.8%*	*3,718*	*0.0%*
2020	*16,501*	*125*	*0.8%*		*736,617*	*0.8%*	*3,720*	*0.0%*
2021	*16,624*	*122*	*0.7%*		*742,952*	*0.9%*	*3,724*	*0.1%*
2022	*16,742*	*118*	*0.7%*		*749,564*	*0.9%*	*3,731*	*0.2%*
2023	*16,858*	*116*	*0.7%*		*756,178*	*0.9%*	*3,738*	*0.2%*
2024	*16,968*	*111*	*0.7%*		*762,818*	*0.9%*	*3,746*	*0.2%*
2025	*17,076*	*108*	*0.6%*		*769,703*	*0.9%*	*3,756*	*0.3%*
2026	*17,184*	*108*	*0.6%*		*776,781*	*0.9%*	*3,767*	*0.3%*
2027	*17,289*	*105*	*0.6%*		*784,008*	*0.9%*	*3,779*	*0.3%*
2028	*17,394*	*105*	*0.6%*		*791,234*	*0.9%*	*3,791*	*0.3%*

4.2.3 Large Commercial & Industrial

The large commercial & industrial class, referenced as Large C&I in Big Rivers' 2013 Load Forecast, is defined as all commercial and industrial customers that are served under Big Rivers' LIC tariff. These customers tend to be relatively large, with annual peak demand equal to or exceeding 1 MW. Large C&I sales for Big Rivers' three Members are projected to be essentially flat throughout the forecast period, as the forecast includes no new customers for this classification.

Table 4.7
Large Commercial & Industrial

	Number of Customers[30]	Change per Yr.	% Change per Yr.	Energy Sales (MWH)	% Change per Yr.	Avg. kWh per Mo.	% Change per Yr.
2009	17			932,868		4,572,882	
2010	17	0	0.0%	966,126	3.6%	4,735,912	3.6%
2011	19	2	11.8%	974,046	0.8%	4,272,130	-9.8%
2012	19	0	0.0%	962,599	-1.2%	4,221,926	-1.2%
2013	20	1	5.3%	958,781	-0.4%	3,994,922	-5.4%
2014	20	0	0.0%	981,796	2.4%	4,090,818	2.4%
2015	20	0	0.0%	985,814	0.4%	4,107,558	0.4%
2016	20	0	0.0%	985,325	0.0%	4,105,521	0.0%
2017	20	0	0.0%	982,555	-0.3%	4,093,980	-0.3%
2018	20	0	0.0%	982,555	0.0%	4,093,980	0.0%
2019	20	0	0.0%	982,555	0.0%	4,093,980	0.0%
2020	20	0	0.0%	982,555	0.0%	4,093,980	0.0%
2021	20	0	0.0%	982,555	0.0%	4,093,980	0.0%
2022	20	0	0.0%	982,555	0.0%	4,093,980	0.0%
2023	20	0	0.0%	982,555	0.0%	4,093,980	0.0%
2024	20	0	0.0%	982,555	0.0%	4,093,980	0.0%
2025	20	0	0.0%	982,555	0.0%	4,093,980	0.0%
2026	20	0	0.0%	982,555	0.0%	4,093,980	0.0%
2027	20	0	0.0%	982,555	0.0%	4,093,980	0.0%
2028	20	0	0.0%	982,555	0.0%	4,093,980	0.0%

Number of customers and energy sales for all years exclude aluminum smelters

[30] The 2013 Load Forecast assumed 20 large industrial customers; however, there are currently 21 large industrial customers on the Big Rivers system. One of the 21 large industrials was expected to remove service after operations were shut down; however, it chose to maintain service at the site at a de minimis level of capacity and energy.

4.2.4 Replacement Load

The 2013 Load Forecast includes replacement load, which is defined as current and future sales corresponding to approximately 800 MW of capacity available to Big Rivers following the smelter contract terminations. Replacement load is envisioned to take any of a number of forms: market sales, economic development load, long-term power agreements, capacity sales, or other potential transactions that bring value to Big Rivers' Members. Big Rivers has taken steps to mitigate the effects of smelter contract terminations, including implementation of a Load Concentration Analysis and Mitigation Plan (the Mitigation Plan) that was submitted to the Commission under a petition for confidential treatment in Big Rivers' response to Item 44b of Kentucky Industrial Utility Customers, Inc.'s Second Request for Information in Case No. 2012-00063[31] filed on July 6, 2012. The plan calls for several steps.

Big Rivers implemented the first steps when it petitioned the Commission for rate relief in Case Nos. 2012-00535 and 2013-00199 to help address the forecasted revenue shortfalls stemming from the smelter contract terminations. The second step calls for Big Rivers to market all excess power when the market price is greater than marginal generation cost. From a forecast standpoint, the market prices in MISO for the near term indicate that off-system sales margins will likely remain depressed, so this step is not expected to prevent Big Rivers from idling the Coleman Station in the near term, although Big Rivers has executed a forward sale of power from Wilson Station through the end of February 2015.

The third step calls for Big Rivers to idle or reduce generation when the market price does not support the cost of generating. Big Rivers is addressing this step with plans to temporarily idle the 443 MW Coleman Station. Because the wholesale power market continues to be depressed and is not expected to support the total production cost of Coleman generation in the near term, Big Rivers plans to idle Coleman will eliminate the plant's variable cost of production and reduce the fixed departmental expense, labor, and labor overhead costs to Big Rivers' Members. Big Rivers currently projects that market prices will return to a level that may justify returning the idled plant to operational status in 2016 or 2017 as demonstrated in the base case of this IRP; however, the Coleman Station is not required to serve replacement load until 2019. Big Rivers will continue to constantly monitor market conditions to ensure the Coleman Station provides optimum value to Big Rivers' Members in the future.

The fourth step calls for Big Rivers to evaluate options to execute forward bilateral sales agreements with counterparties, enter into wholesale power contracts, and/or participate in capacity markets to find load replacement for the load previously consumed by the smelters. Big Rivers has also considered the possibility of selling or leasing generating units and would be willing to pursue such an option should it prove beneficial to Big Rivers and its Members. As of the date of this IRP, Big Rivers has offered multiple parties the option to purchase the Coleman and Wilson Stations. Despite expecting several years for load replacement to achieve full fruition, Big Rivers' mitigation efforts have already resulted in a 67 MW sale to begin in 2018 as well as several other current opportunities that look promising. Big

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[31] *In the Matter of: Application of Big Rivers Electric Corporation for Approval of its 2012 Environmental Compliance Plan, for Approval of its Amended Environmental Cost Recovery Surcharge Tariff, for Certificates of Public Convenience and Necessity, and for Authority to Establish a Regulatory Account*, Case No. 2012-00063.

Rivers continues to evaluate a range of options to arrive at the most cost-effective alternatives possible for Big Rivers' Members.

Replacement load is included in the base case and all scenarios and sensitivities for this IRP. Projections for replacement load that Big Rivers used in the 2013 Load Forecast are set forth in Table 4.8.

Table 4.8
Replacement Load

	Energy Sales (MWH)	*% Change per Yr.*	*Peak Demand (MW)*	*% Change per Yr.*
2009				
2010				
2011				
2012				
2013				
2014				
2015				
2016	*658,800*		*100*	
2017	*1,314,000*	*99.5%*	*200*	*100.0%*
2018	*1,971,000*	*50.0%*	*300*	*50.0%*
2019	*2,628,000*	*33.3%*	*400*	*33.3%*
2020	*3,952,800*	*50.4%*	*600*	*50.0%*
2021	*5,256,000*	*33.0%*	*800*	*33.3%*
2022	*5,256,000*	*0.0%*	*800*	*0.0%*
2023	*5,256,000*	*0.0%*	*800*	*0.0%*
2024	*5,270,400*	*0.3%*	*800*	*0.0%*
2025	*5,256,000*	*-0.3%*	*800*	*0.0%*
2026	*5,256,000*	*0.0%*	*800*	*0.0%*
2027	*5,256,000*	*0.0%*	*800*	*0.0%*
2028	*5,270,400*	*0.3%*	*800*	*0.0%*

4.2.5 Other

Other energy includes sales for street lighting and irrigation and is shown in Table 4.9. Sales for both classes combined represent less than 0.1 percent of total system sales. Utility use is not addressed directly in the 2013 Load Forecast; rather, it is addressed indirectly as utility own use and included in rural system distribution losses.

Table 4.9
Other

	Number of Customers	Change per Yr.	% Change per Yr.	Energy Sales (MWH)	% Change per Yr.	Avg. kWh per Mo.	% Change per Yr.
2009	94			3,653		3,250	
2010	97	3	3.0%	3,794	3.9%	3,276	0.8%
2011	94	(3)	-3.0%	3,678	-3.1%	3,275	0.0%
2012	97	3	3.1%	3,894	5.9%	3,363	2.7%
2013	96	(1)	-0.5%	3,904	0.3%	3,389	0.8%
2014	97	1	1.0%	3,883	-0.5%	3,336	-1.6%
2015	98	1	1.0%	3,854	-0.7%	3,278	-1.7%
2016	98	0	0.0%	3,847	-0.2%	3,272	-0.2%
2017	99	1	1.0%	3,875	0.7%	3,262	-0.3%
2018	99	0	0.0%	3,901	0.7%	3,284	0.7%
2019	100	1	1.0%	3,927	0.7%	3,272	-0.3%
2020	100	0	0.0%	3,954	0.7%	3,295	0.7%
2021	101	1	1.0%	3,983	0.7%	3,287	-0.3%
2022	101	0	0.0%	4,014	0.8%	3,312	0.8%
2023	102	1	1.0%	4,044	0.8%	3,304	-0.2%
2024	102	0	0.0%	4,075	0.8%	3,329	0.8%
2025	103	1	1.0%	4,107	0.8%	3,323	-0.2%
2026	103	0	0.0%	4,139	0.8%	3,349	0.8%
2027	104	1	1.0%	4,172	0.8%	3,343	-0.2%
2028	105	1	1.0%	4,205	0.8%	3,338	-0.2%

4.2.6 Economic Development

Big Rivers continues to support its Members' economic development efforts. Economic development in the area creates many positive impacts for Big Rivers, its Members, the region, and the Commonwealth of Kentucky. Big Rivers has proposed an economic development incentive rate in a number of its proposals in an effort to incentivize business growth in western Kentucky. The economic development incentive rate contemplated by Big Rivers is envisioned for a period of up to 4 years, with a required contractual commitment for up to an additional 4 years at tariffed rates. Big Rivers believes that economic development rates offered to encourage new or expanded large industrial load should be implemented by special contract between and among Big Rivers, its respective distribution cooperative and the large industrial customer. Any such contract would be submitted to the Commission for review in accordance with the principles established by the Commission in Administrative Case No. 327.[32] Special contracts would also require the approval of Big Rivers' Board of Directors and the RUS. In this IRP, Big Rivers assumed no specific economic development success in the base case; however, economic development is envisioned to be a possible component of replacement load. Please see Section 4.2.4 for a discussion of replacement load. In the High Economic Sensitivity performed, Big Rivers assumed a portion of replacement load was internal load growth driven by economic development success.

4.2.7 Firm and Non-Firm Load Contracts

Big Rivers provides wholesale electric service to its three Members: Kenergy, JPEC, and MCRECC. The current tariff under which Big Rivers provides service is on file with the Commission;[33] that tariff has an effective date of February 1, 2014. Big Rivers has no contractual commitments for firm power with any retail customers.

Big Rivers offers a Voluntary Curtailment Rider, which provides a means for potentially reducing system peak demand during peak periods. On March 10, 2000, Big Rivers, in conjunction with JPEC, Kenergy, and MCRECC, filed the Voluntary Curtailment Rider with the Commission. The Commission approved the Voluntary Curtailment Rider as filed in its Order dated April 6, 2000, in Case No. 2000-00116.[34] Since the rider is voluntary, it is not considered as a means for reducing load in this IRP. As presented in Table 4.10, there have been four voluntary curtailments, one in 2008 and three in 2009, affecting two customers, and reducing load by an estimated 1 to 25 MW.

Table 4.10
2000-2013 Voluntary Industrial Curtailment Results

Year	*Number of Curtailments*	*Load Reduction (MW)*
2000-2007	*0*	*n/a*
2008	*1*	*20*
2009	*3*	*1 to 25*
2010-2013	*0*	*n/a*

4.3 Weather Adjusted Energy and Peak Demand Requirements

Rural system energy consumption and peak demand are impacted by prevailing weather. Energy sales and peak demand for direct serve customers are not weather sensitive. Both extreme and mild weather conditions have been experienced over the most recent four years. As measured by degree days, 2010

[32] *In the Matter of: A Review of the Adequacy of Kentucky's Generation Capacity and Transmission System*, Administrative Case No. 327.
[33] That tariff is also accessible from Big Rivers' corporate internet site at www.bigrivers.com/regulatory.
[34] *In the Matter of: Joint Tariff Filing of Big Rivers Electric Corporation, Jackson Purchase Energy Corporation, Kenergy Corp., and Meade County rural Electric Cooperative Corporation*, Case No. 2000-00116.

was the hottest year in over 20 years, and 2010 was the coldest year since 1997. More recently, January 2014 represented one of the most extreme winter months Big Rivers has experienced in the last 20 years, resulting in a new all-time peak of 741 MW (including losses). Table 4.11 presents actual and weather adjusted energy and peak demand requirements for recent years.

Table 4.11
Weather Normalized Native System Energy and Peak Demand

	Energy (MWH)		*Winter Peak (MW)*		*Summer Peak (MW)*	
	Actual	*Normal*	*Actual*	*Normal*	*Actual*	*Normal*
2004	*3,130,003*	*3,190,560*	*533*	*517*	*599*	*632*
2005	*3,233,941*	*3,224,651*	*557*	*575*	*613*	*618*
2006	*3,188,056*	*3,255,225*	*551*	*609*	*626*	*647*
2007	*3,327,805*	*3,262,908*	*605*	*608*	*654*	*625*
2008	*3,312,709*	*3,295,072*	*614*	*629*	*611*	*619*
2009	*3,206,088*	*3,251,489*	*668*	*642*	*606*	*623*
2010	*3,445,404*	*3,317,219*	*647*	*645*	*657*	*625*
2011	*3,344,964*	*3,337,053*	*621*	*615*	*652*	*650*
2012	*3,283,877*	*3,284,501*	*569*	*617*	*654*	*630*
2013	*3,733,783*	*3,716,653*	*597*	*597*	*609*	*606*

Values represent energy and peak demand at the distribution level

Under normal peaking weather conditions, Big Rivers' annual peak demand is projected to occur during the summer season. Historical data shows, however, that Big Rivers' actual annual peak demand was set during winter months in 2008 and 2009. The impact of severe weather is greater during winter months than summer months due to supplemental electric strip heating; therefore, while the base case forecast shows Big Rivers to be summer peaking, under the most extreme weather conditions, the system is most likely to be winter peaking.

4.4 Impact of Existing and Future Energy Efficiency and Demand-Side Management Programs

Big Rivers assisted its Members with the implementation of 10 energy efficiency programs in 2010, and added two additional programs in 2013 for a total of 12 programs. The projected cumulative impact of these programs beginning in 2014 is presented in Table 4.12 and is described in greater detail in Section 5.1. Across the 2011-2013 timeframe, the programs continued to grow and yield increasing levels of deemed savings. Estimated cumulative energy savings have increased from 1,100 MWh in 2011 to nearly 14,000 MWh in 2013. Estimated winter peak demand savings have increased from 0.5 MW in 2011 to over 4.1 MW in 2013. Historical estimated program impacts have been significantly higher than modeled impacts due to higher-than-expected Members' member-owners participation rates and lower administration costs than assumed, which allowed additional measures to be implemented than assumed in previous studies. The impacts of existing programs are quantified indirectly in the 2013 Load

Forecast through historical sales. The impacts of new programs and increased participation in existing programs are captured in the 2013 Load Forecast through post-modeling adjustments.

Table 4.12
Estimated Future DSM Program Impacts

Year	*Impact on Energy Requirements (MWh)*	*Impact on Winter Peak Demand (MW)*	*Impact on Summer Peak Demand (MW)*
2014	*5,022*	*0.7*	*0.9*
2015	*10,311*	*1.3*	*1.3*
2016	*15,823*	*1.9*	*1.7*
2017	*21,518*	*2.5*	*2.2*
2018	*27,389*	*3.1*	*2.6*
2019	*33,158*	*3.6*	*3.0*
2020	*39,034*	*4.1*	*3.4*
2021	*43,111*	*4.0*	*3.3*
2022	*48,343*	*4.4*	*3.5*
2023	*53,686*	*4.9*	*3.8*
2024	*59,192*	*5.2*	*4.0*
2025	*65,078*	*5.6*	*4.2*
2026	*71,506*	*6.0*	*4.4*
2027	*78,443*	*6.3*	*4.6*
2028	*86,065*	*6.7*	*4.8*

Below are programs that are not tracked for impact because they are educational in nature and/or not easily quantifiable. The impact for deemed savings is described in Section 5.

- **Member websites:** Each of the Member distribution cooperative websites provides easy-to-use Home Energy Suites. The Suites provide education and calculation methods to improve efficiency and save energy in the home. Adjustable inputs specific to a home allows customers to compare their current energy use to estimated energy use resulting from various improvements in efficiency.
- **Energy Use Assessments:** These assessments are provided to commercial and industrial customers upon request. Walk through energy audits help identify simple and low cost efficiency measures that customers can install or implement themselves. Third party service providers such as the Kentucky Pollution Prevention Center and Department for Energy

Development and Independence[35] assist customers in achieving energy reduction goals[36]. Educational programs are also available for employees of commercial and industrial members.

- **Renewable Energy:** Big Rivers offers renewable energy to its Members. Big Rivers has purchased energy from an ENERGY STAR® certified Combined Heat and Power ("CHP") project operated by Domtar, Inc., a specialty paper manufacturer. The power is generated from wood chips that are waste byproducts of the paper manufacturing process. Customers wishing to purchase this renewable energy can contract with any of the Members.
- **Energy Savings Analysis:** Big Rivers provided energy saving analyses to industrial and large commercial customers by combining efforts with the Members, the Department of Energy ("DOE"[37]), and the University of Louisville's Kentucky Pollution Prevention Center.[38]
- **Power Factor Correction:** Members' staffs provide assistance to correct lagging power factor at a Commercial or Industrial ("C&I") facility. These corrections save money for the customer and improve the efficiency of both transmission and distribution facilities.
- **Technology Evaluation:** Members' staffs assist in the evaluation and implementation of technologies that benefit the productivity, profitability and energy efficiency of a C&I facility.

4.5 Anticipated Changes in Load Characteristics

The biggest anticipated change in future load characteristics is the reduction in total load and energy requirements resulting from the smelter contract terminations. Load for the two smelters totaled approximately 850 MW, and annual energy requirements were just above 7 million MWH at a 98% load factor. Except as otherwise noted, all historical and projected load and energy requirements analyzed in the development of Big Rivers' 2014 IRP exclude amounts for the two smelters.

Big Rivers' hourly native system load shape for 2013 is presented in Figure 4.1. The system can be summer or winter peaking depending on the severity of seasonal temperatures; however, the system is projected to be [redacted] peaking throughout the next 15 years.

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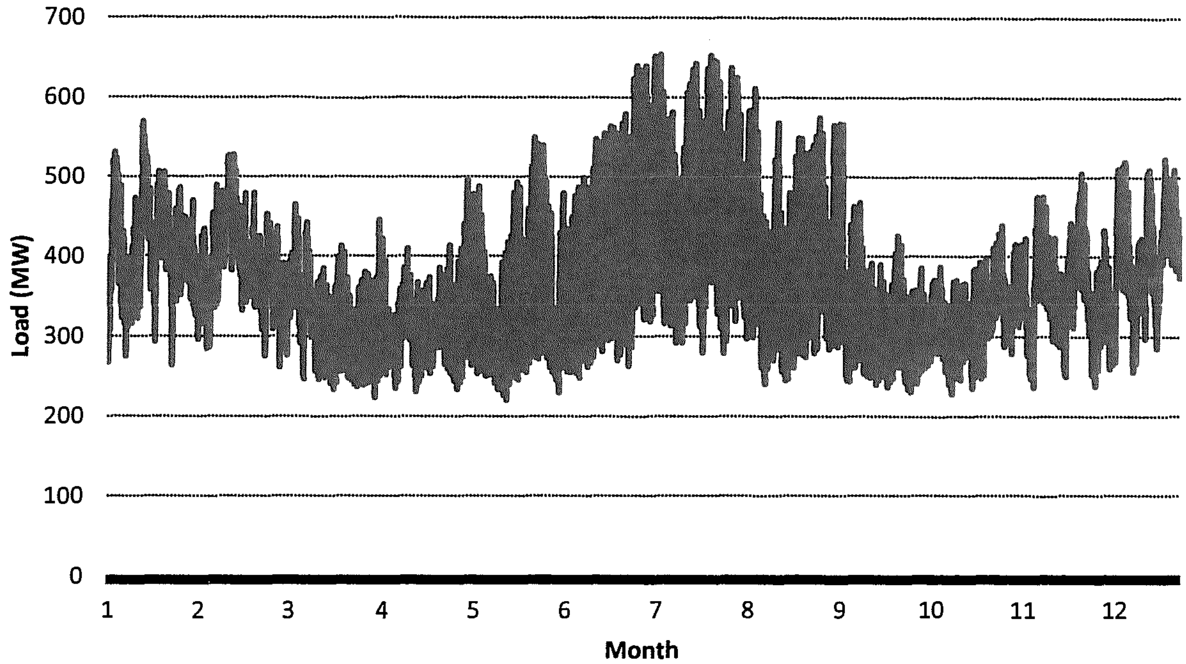
[35] http://energy.ky.gov/Pages/default.aspx
[36] Kentucky Pollution Prevention Center, https://louisville.edu/kppc/es/technical_services.html
Kentucky's Department for Energy Development and Independence, http://energy.ky.gov/Pages/default.aspx
[37] http://energy.gov/
[38] https://louisville.edu/kppc/

Figure 4.1
2013 Annual Load Shape



Annual load duration curves for 2013 are presented in Figures 4.2 and 4.3. Native system load factor is approximately 58 percent. Load factor for the direct serve category and HMP&L are slightly higher than the system average.

Figure 4.2
2013 Annual Load Duration Curve

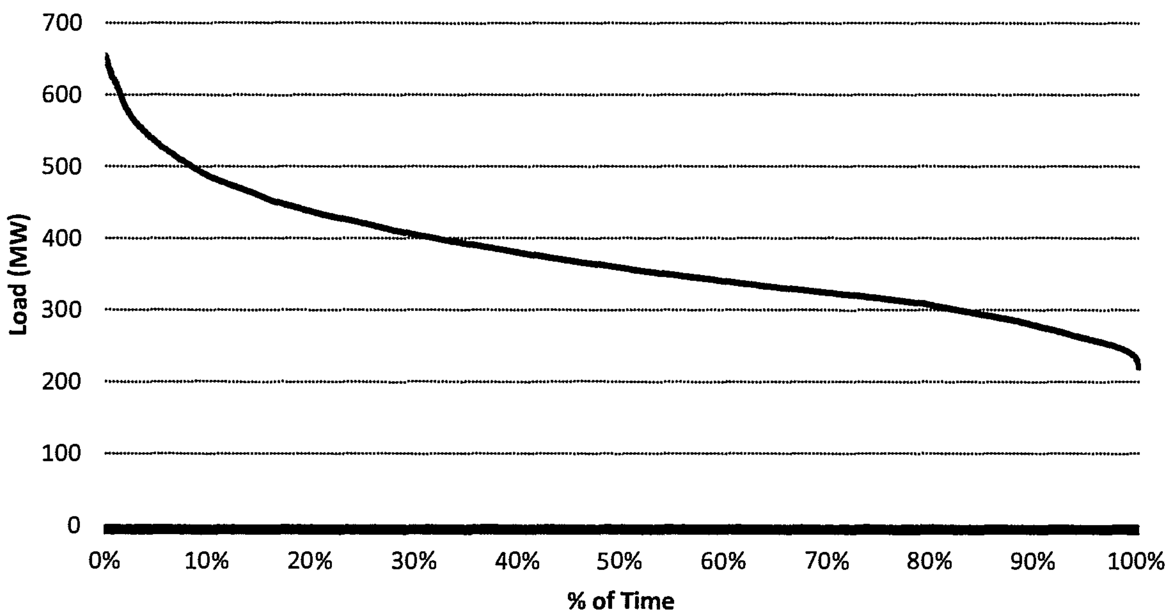
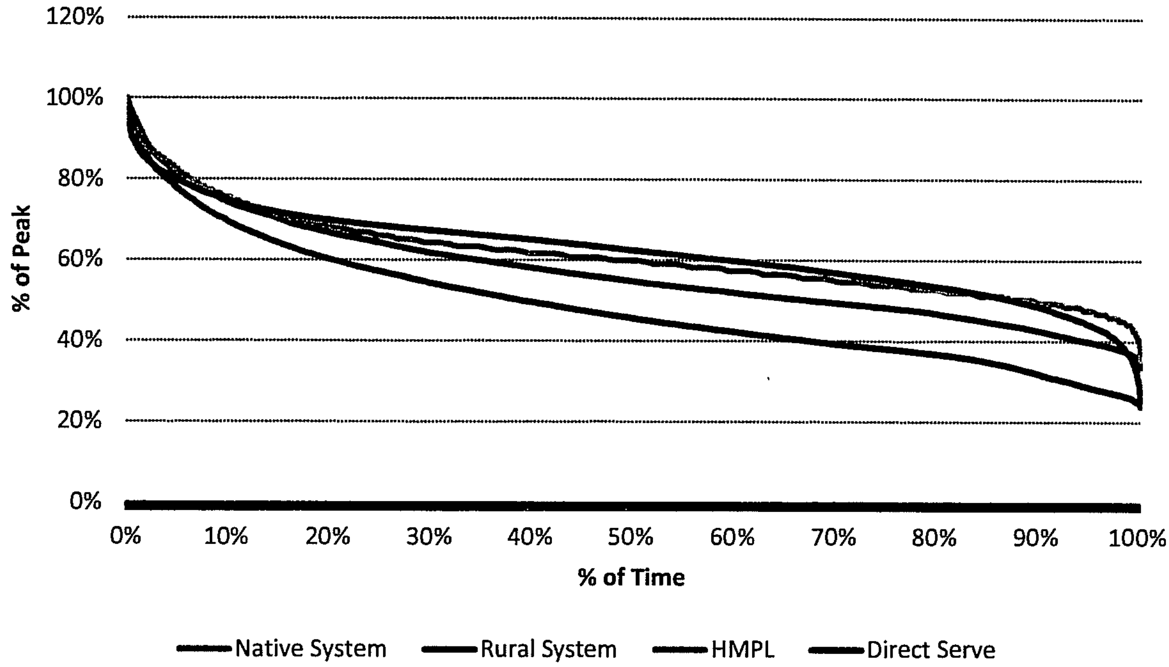
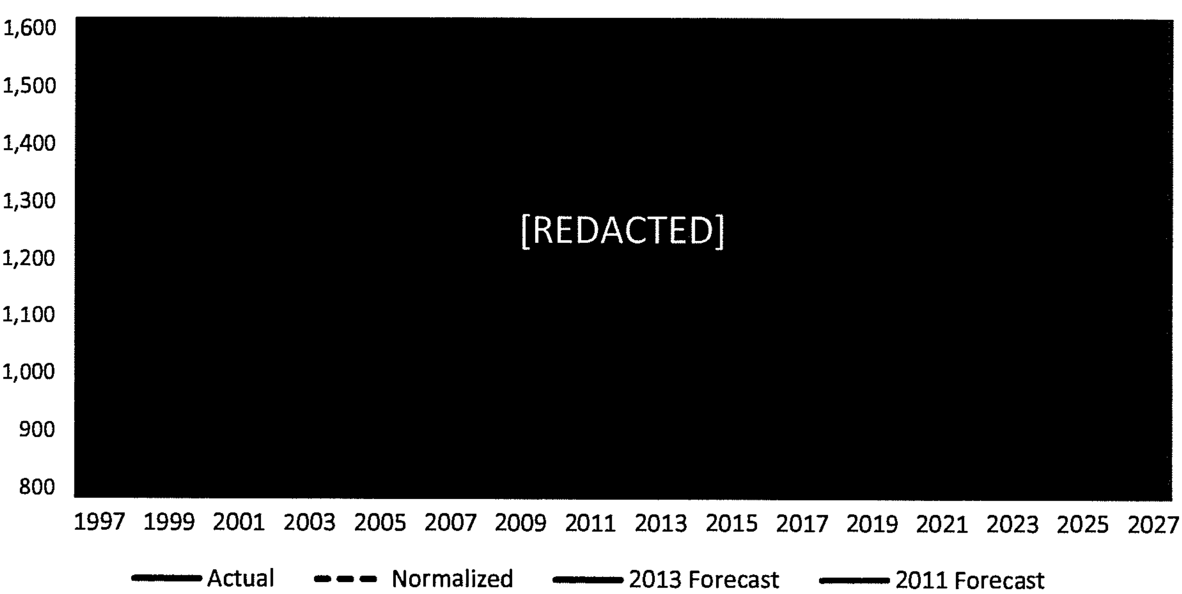


Figure 4.3
2013 Annual Load Duration Curves by Sector



Residential Consumption – Average kWh use per customer has leveled in recent years due primarily to energy conservation, reductions in lighting consumption associated with federal lighting standards, and increases in appliance efficiencies. Consumption is projected to [redacted] over the long term. Figure 4.4 presents average monthly kWh per customer for historical and projected periods.

Figure 4.4
Average Monthly Residential kWh Consumption per Customer by Year



4.6 Load Forecast Methodology

Big Rivers' 2013 Load Forecast was developed using quantitative and qualitative methods. Econometrics was used to develop forecasting models to project the number of customers, average energy consumption per customer, and peak demand for the rural system. Informed judgment, combined with historical trends, was used to project energy consumption and peak demand for each direct serve customer. Rural system projections were broken down by class based on current proportions, adjusted to reflect anticipated changes in the proportions over the next 15 years.

Big Rivers contracted with GDS to assist in developing the load forecast. GDS developed preliminary economic outlooks and load forecasts for each of Big Rivers' three Members. The preliminary forecasts were reviewed with management from the Members. The Members' forecasts were finalized and then aggregated to the Big Rivers level.

Refer to Appendix A, 2013 Load Forecast, for more details regarding Big Rivers' forecasting process and model specifications.

4.6.1 Load Forecast Database

Energy consumption and peak demand are influenced by a number of factors; therefore, a considerable amount of data is obtained in developing Big Rivers' load forecast. Energy, peak demand, and pricing data at the Big Rivers and Member levels are collected. Economic data is obtained to update the service area economic outlook. Various types of weather data for local weather stations are collected. Additionally, end-use and appliance efficiency data are developed through surveys or obtained via independent sources. Table 4.13 identifies the data that are regularly collected and used in development of the load forecast. Refer to Appendix A, 2013 Load Forecast, Section 3 for more details regarding the load forecast database.

Electric System Data – Number of customers, kWh sales, and sales revenue by customer class and month is collected from each Member distribution cooperative. Additionally, rural system demand coincident with the overall Big Rivers rural system each month is collected. Hourly load data for the different components of Big Rivers' control area (rural system by distribution cooperative, HMP&L, and direct serve load) is available.

Economic Data - The economic outlook used in development of the 2013 Load Forecast was obtained from Moody's Analytics.[39] Data representing those counties in which the vast majority of Big Rivers' Members' customers reside is used to develop service area economic outlooks for each of Big Rivers' Members[40]. Historical and projected data series for total population, number of households, average household income, total employment, retail sales, and gross regional product are collected. The economic outlook contains data on a monthly basis for 1980 – 2040. Refer to Appendix A, 2013 Load Forecast, Section 4 for further details on the economic data used in preparing the load forecast.

[39] Moody's Analytics, February 2013.

[40] Kenergy (Caldwell, Crittenden, Daviess, Hancock, Henderson, Hopkins, Lyon, Mclean, Ohio, Union, Webster)
JPEC (Ballard, Carlisle, Graves, Livingston, Marshall, McCracken)
MCRECC (Breckinridge, Grayson, Meade, Ohio)

Table 4.13
Load Forecast Database

Data Category	*Data Source*	*Data Element*
Electric System	*Big Rivers and its three member distribution cooperatives*	*Number of customers, kWh sales and revenues by class, system peak demand*
Economic	*Moody's Analytics*	*Number of households* *Population* *Total employment* *Average household income* *Retail sales* *GDP Price index*
Weather	*National Oceanic and Atmospheric Administration*	*Heating and cooling degree days* *Temperature*
Price	*Big Rivers and its three member distribution cooperatives*	*Average cents per kWh*
End-use	*Big Rivers* *Energy Information Administration*	*Appliance saturations* *Appliance efficiencies* *Appliance unit energy consumption (kWh)*
Housing Characteristics	*Big Rivers* *Energy Information Administration*	*Size of home* *Number of people per home*

Weather Data – Monthly heating and cooling degree days, and maximum and minimum monthly temperatures are collected for the Evansville, Indiana; Paducah, Kentucky; and Louisville, Kentucky weather stations[41]. Additionally, Big Rivers subscribes to the MDA EarthSat Weather[42], which provides hourly observations for multiple weather variables.

End-Use Data – Big Rivers conducts residential customer surveys periodically to collect data needed to estimate market share for different types of heating, cooling, and water heating systems and various household appliances. Additionally, data regarding housing characteristics is collected. Surveys were conducted in 2013 and 2009.

Appliance Efficiency Data – Big Rivers collects appliance efficiency information published by the EIA in its Annual Energy Outlook[43]. Average efficiencies for heating, cooling, water heating and other

[41] National Oceanic and Atmospheric Administration, http://www.ncdc.noaa.gov/IPS/lcd/lcd.html
[42] http://weather.earthsat.com/
[43] http://www.eia.gov/analysis/projection-data.cfm#annualproj, Table 31.

household appliances are obtained and provide information used in developing projections of average energy use per customer for rural system customers.

Housing Characteristics Data – Big Rivers conducts residential customer surveys periodically to collect data needed to estimate housing characteristics. Surveys were conducted in 2013 and 2009.

4.6.2 Forecast Model Inputs

Electric System Data – Number of customers, kWh sales, and sales revenue are obtained by customer class from the RUS Form 7 for each Member distribution cooperative. The data is available on a monthly basis. Monthly peak demand for the rural system is available from the data used in preparing wholesale power bills to the Members. Monthly energy and peak demand for each large industrial customer is provided by the Members. Hourly load data is available at different levels, including the native system, rural system, HMP&L, and direct serve categories.

Price of Electricity - The energy and peak demand forecasts developed for each of Big Rivers' three Members include the impacts of projected increases in the real price of electricity over the forecast horizon. Average price reflects total rural system revenue divided by total rural system kWh. The amount is then expressed in real, or deflated, terms by applying the GDP price index ($2005=100). Projected retail electricity prices are developed by Big Rivers in collaboration with the Members. The price of competing fuels is quantified indirectly in the forecast through changes in the markets shares of electric space heating and electric water heating.

Economic Impacts - The forecast captures changes in number of households, average household income, total employment, and retail sales. Number of households is the independent variable in the residential customer models. Household income is one of the driver variables specified in the residential use per customer models. Employment is the driver variable in the small commercial customer models and retail sales is an independent variable in the small commercial energy sales models. The projected values for each of these demographic and economic variables were obtained from Moody's Analytics.[44] The economic outlook takes into account the impacts of the 2008-2009 economic recession. Refer to Appendix A, 2013 Load Forecast, Section 4, Table 4.1, for the weighted Big Rivers average values.

Household Market Share - Household market share represents the proportion of county households that are served by Big Rivers' Members measured as the ratio of number of residential customers to number of households. The majority of customers served by Big Rivers' Members are located in rural counties (no major metropolitan areas). Over time, the Members' household market shares have demonstrated an increasing trend.

Appliance Market Share - The Members' forecasts incorporate service-area specific market shares of electric appliances and changes in technology. Projections of market share are based on Big Rivers' appliance saturation survey data, census data, and data obtained from the EIA. The market shares for electric heating, electric water heating, and electric air conditioning are all projected to increase throughout the forecast horizon, but at a decreasing rate as maximum saturation levels are approached.

[44] Moody's Analytics, February 2013

Appliance Efficiency – Appliance efficiencies are included in the forecast to account for changes in consumption due to changes in the average efficiency of the major electric equipment and appliances in use. Changes in appliance efficiencies occur when customers replace older equipment with newer models. The appliance efficiency information included in the 2013 Load Forecast is obtained from EIA's Annual Energy Outlook.

Weather Data – The load forecasting models incorporate weather data for Paducah, Kentucky, Louisville, Kentucky, and Evansville, Indiana[45]. Heating and cooling degree days are included in the model used to forecast rural system average energy use per customer to account for changes in consumption resulting from changes in weather. Similarly, peak day degree days are included in the model used to forecast rural system peak demand to quantify the extremity of weather during peaking periods.

DSM and Government Sponsored Programs – The forecast implicitly includes through the historical energy sales data the impacts of Big Rivers' existing DSM programs and current educational and conservation programs. Impacts from increased participation in existing programs and from new programs is obtained from Big Rivers' DSM studies and included in the 2013 Load Forecast as a post-modeling adjustment.

4.6.3 Key Load Forecast Assumptions

The key assumptions made during the development of the 2013 Load Forecast focused on changes in the economy, weather, retail electricity price, appliance market shares, and appliance efficiencies. The assumptions apply broadly to each of the three Members and to Big Rivers.

Economic Outlook – Big Rivers' management concluded that changes in economic activity over the forecast horizon are reasonably represented by the projections obtained from Moody's Analytics. Economic outlooks were developed individually for each Member and quantified in the forecasting models. Assumptions regarding the economic outlook and projections for each of the data series are presented in Appendix A, 2013 Load Forecast, Section 4.

Weather – The forecast is based on the assumption that heating and cooling degree days during the forecast horizon would be equal to the most recent 20-year averages. It was assumed that degree days for Paducah, Kentucky, Louisville, Kentucky, and Evansville, Indiana provided reliable coverage of weather conditions for the Big Rivers service area. Assumptions regarding projected heating- and cooling-degree days are presented in Appendix A, 2013 Load Forecast, Section 4. Historical and projected degree days are presented in Appendix A, 2013 Load Forecast, Table 2.1 (page 10).

End-Use Characteristics – Assumptions regarding future changes in appliance saturation levels are based on historical trends developed from Big Rivers' appliance saturation surveys and data obtained from the EIA. It is assumed that the market shares for central electric space heating, central air conditioning, and electric water heating will continue to increase over time, but at declining rates as

[45] The 2013 Load Forecast identifies the Paducah, Kentucky and Evansville, Indiana weather stations as the sources of weather data for the load forecast. It should be noted that weather data for the Louisville, Kentucky station was also included as a source of weather data.

their respective maximum saturation levels are approached. Assumptions regarding changes in appliance efficiencies are based on information obtained from EIA's 2013 Annual Energy Outlook.

Retail Electricity Prices – The average price of electricity to rural system customers was expected to increase, in real terms (adjusted for inflation), 39% by 2016 and then at the rate of inflation from 2016-2028 in the load forecast. The impact on retail rates over the near term was estimated to reflect Big Rivers' anticipated wholesale price increases to the Members proposed in Case No. 2012-00535 and Case No. 2013-00199. The costs of adding pollution control equipment for regulations not yet in effect are evaluated though sensitivity analyses. Table 4.14 presents an average of real Member retail prices for the residential and commercial classifications. The prices represent average cents per kWh.

Table 4.14
Rural Delivery Service
Real[46] Average Electricity Price (¢ per kWh)

Year	*Average Price*
2009	*6.31*
2010	*6.25*
2011	*6.41*
2012	*6.77*
2013	*6.74*
2014	[redacted]
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	
2025	
2026	
2027	
2028	

DSM, and Government Sponsored Programs – In development of the 2013 Load Forecast, the assumptions regarding the impacts of future DSM and government sponsored programs are based on Big Rivers' DSM study that was completed and was included as an appendix to the 2010 IRP.[47] The impacts of existing programs are projected to increase as the level of customer participation is projected

[46] Adjusted for inflation. Rates in this table are as proposed in Case No. 2013-00199.

[47] Results from Big Rivers' 2014 DSM study are reflected in development of the 2014 IRP.

to increase. For additional information, please see Section 5 of this IRP or Appendix B, DSM Potential Study.

4.6.4 Forecast Model Specification

Forecast models are developed to forecast the number of customers, average use per customer, and peak demand for the rural system class. The number of customers and average use per customer models are developed individually for each of Big Rivers' three Member distribution cooperatives. The rural system peak demand model is developed at the Big Rivers level, and the total is allocated across the three Members. Exponential smoothing and econometric modeling are the two modeling approaches used. All models are expressed in linear functional form and were developed using monthly time series data. Itron's MetrixND software is used to perform the modeling analysis.

Rural System Customers – Two models are used to produce the customer forecast. Monthly projections for the first 12 months of the forecast horizon (year 2013) are based on an exponential smoothing model. The short-term model captures the most recent historical trend in changes in the number of customers and extrapolates that trend for 12 months. Projections for 2014 and beyond are based on an econometric model that specifies a relationship between number of customers, number of households, and household market share. Additionally, an autoregressive parameter is included in the econometric model to correct for serial first-order autocorrelation, which is commonly seen in models specifying time series data. Theoretically, the number of rural system customers increases when the number of households in the service area increases, and the rate of change is further directly influenced by changes in household market share.

The short-term exponential smoothing model produces a forecast that is slightly lower than projections based on the econometric model. The exponential smoothing model is considered most accurate for the immediate near term as it captures seasonal changes and patterns, and its mean absolute percent error ("MAPE") is slightly lower than the econometric model. The econometric model is most appropriate for the long term because it captures the impacts of long term changes in the number of households and household market share.

The same modeling approach is applicable for each of Big Rivers' three Members. The econometric model for each Member is expressed in linear form and takes the specification:

$$\mathbf{RCUST} = \beta_0 + \beta_1\,(\mathbf{HH}) + \beta_2\,(\mathbf{HHMKT}) + \varepsilon$$

Where

RCUST	=	Number of rural system customers
HH	=	Number of households
HHMKT	=	Household market share
β_0	=	Coefficient for the model constant, or intercept
β_1	=	Coefficient for the Households parameter
β_2	=	Coefficient for the Households Market Share parameter
ε	=	Unexplained model error

Number of households, in conjunction with household market share, is the driving demographic influence of changes in the number of customers. The breakdown of rural system customers is approximately 86 percent residential and 14 percent commercial. Theoretically, change in employment is typically considered the best measure of changes in the number of commercial customers. However, from a statistical modeling perspective, number of households and employment are highly correlated, and severe collinearity problems exist when both variables are specified. As a result, employment was not included in the final model specification.

Refer to Appendix A of this IRP, Load Forecast, Appendix D, Econometric Model Specifications, for the statistical output for the individual customer models.

Rural System Energy Use per Customer – The model used to forecast average use per customer specifies a relationship between energy consumption, average household income, price of electricity, appliance market share, appliance efficiency, and degree days. Theoretically, average energy use is positively correlated with household income, electric appliance market share, and degree days. Conversely, average use per customer is expected to fall when retail electricity price and appliance efficiencies rise.

The energy use model for each Member is expressed in linear form and takes the specification:

$$
\begin{aligned}
\mathbf{RUSE} = \beta_0 &+ \beta_1\,\mathbf{(HHINC)} \\
&+ \beta_2\,\mathbf{(RPR)} \\
&+ \beta_3\,\mathbf{(CDD * ACMKT * ACEFF)} \\
&+ \beta_4\,\mathbf{(HDD * EHMKT * EHEFF)} \\
&+ \beta_5\,\mathbf{(AR)} \\
&+ \varepsilon
\end{aligned}
$$

Where

RUSE	=	Number of rural system customers
HHINC	=	Number of households
RPR	=	Household market share
CDD	=	Cooling degree days
ACMKT	=	Percent of customers with air conditioning
ACEFF	=	Average efficiency of cooling equipment
HDD	=	Heating degree days
EHMKT	=	Percent of customers using electricity as primary heating
EHEFF	=	Average efficiency of electric heating equipment
β_0	=	Coefficient for the model constant, or intercept
β_1	=	Coefficient for the number of households parameter
β_2	=	Coefficient for the real price of electricity parameter
β_3	=	Coefficient for the cooling parameter
β_4	=	Coefficient for the heating parameter
β_5	=	Coefficient for autoregressive parameter
ε	=	Unexplained model error

The average use per customer model is developed using monthly data.

The t-statistic for the average household income parameter in the Kenergy model is significant at the 0.05 alpha, 95% confidence level. The t-statistics for the average household income parameters in the average use models for JPEC and MCRECC are not significant at the 0.05 alpha, 95% confidence level. Growth in average use per customer for both systems was very low over the time periods used to estimate the models (2003-2012 for MCRECC; 1995-2012 for JPEC), averaging less than one-half of one percent per year. Over the same periods, annual growth in average household income for both service areas was considerably higher. Given the changes in consumption and income over time, it is reasonable that the impact of average household income is relatively low, resulting in relatively low t-statistics. No collinearity problems exist between income and any other variables in the model; therefore, the income variable is retained in both the JPEC and MCRECC models to capture its relatively low impact on average use per customer.

The real price of electricity parameter is expressed in annual amounts (value for each month held constant at the annual value) to mitigate the monthly variation in average price, which is expressed as revenue per kWh. The elasticity of demand with respect to price is derived through the regression model rather than input as an independent variable. For all three Members, consumption is inelastic with respect to price, as a one percent change in average annual price does not produce a one percent or higher change in average annual consumption. The price elasticity coefficients for the three Members are listed below and compared to independent sources.

Table 4.15
Price Elasticity

Source	*Price Elasticity*
JPEC	*-0.16*
MCRECC	*-0.16*
Kenergy	*-0.21*
EIA	*-0.15*
RAND	*-0.30*
NREL	*-0.27*

EIA: Assumptions to the 2012 Annual Energy Outlook, Residential Demand Module

(http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2012).pdf)

RAND: Rand Journal of Economics, Vol. 39, Nbr. 3, Autumn 2008, Peter Reiss and Mathew White

http://www.coursehero.com/file/5044646/21-Reiss-White-RJE-2008-Prices-And-Pressures/

NREL: National Renewable Energy Laboratory, February 2006

http://www.nrel.gov/docs/fy06osti/39512.pdf

The heating and cooling parameters are represented as a combination of degree days, equipment market share, and equipment efficiency. Development of the two parameters in this form provides the means for quantifying all three factors in one variable. In development of the heating and cooling data series, degree days take their respective unit values, equipment market shares (percent of customers with electric heating or cooling equipment) take their respective unit values between 0.00 and 1.00, and equipment efficiencies take a value between 1.00 and 0.00, which is computed as the inverse of the average efficiency in each year relative to 1991. The inverse of the relative efficiency is used in development of the heating and cooling data series because it decreases over time and reflects the theoretical assumption that energy consumption falls as equipment efficiency increases. The heating and cooling parameters are significant at the 0.05 alpha, 95% confidence level.

Refer to Appendix A of this IRP, 2013 Load Forecast, Appendix D, Econometric Model Specifications, for the statistical output for the individual average use per customer models.

4.7 Alternative Load Forecast Scenarios

Big Rivers' base case forecast reflects expected economic growth, current environmental Protection Agency ("EPA") regulations, and normal weather conditions. To address the inherent uncertainty related to these factors, long-term high and low range projections are developed. The range forecasts reflect the energy and demand requirements corresponding to more optimistic or pessimistic economic growth, potential EPA and environmental regulations, and mild or extreme weather conditions. Tables 4.16 through 4.21 present the alternative forecast scenarios at the control area level, comprised of Big Rivers' native load, replacement load, and HMP&L load, including generation and transmission losses.

Replacement Load Scenarios – Under the base case, replacement load reaches 800 MW in 2021 and remains flat thereafter. The replacement load sensitivities present energy and peak demand requirements under the assumption that replacement load reaches 800 MW two years earlier than expected, in 2019, and two years later than expected, in 2023.

Table 4.16
Early/Late Replacement Load
Total Requirements (Native, HMP&L, Replacement)

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Early	*Base*	*Late*	*Early*	*Base*	*Late*	*Early*	*Base*	*Late*
2013	*3,976,370*	*3,976,370*	*3,976,370*	*693*	*693*	*693*	*760*	*760*	*760*
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Economy Scenarios – The two economic drivers in the forecasting models, number of households and average household income, are adjusted from base case values to produce the optimistic and pessimistic forecast scenarios. Refer to Appendix A, 2013 Load Forecast, Section 7, for details regarding the economic forecast scenarios. Additionally, under the optimistic case, it is assumed that a portion of the load previously associated with the two aluminum smelters will be replaced through economic development efforts in Big Rivers' territory.

Table 4.17
Optimistic/Pessimistic Economy
Total Requirements (Native, HMP&L, Replacement)

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Pessimistic	*Base*	*Optimistic*	*Pess.*	*Base*	*Opti.*	*Pess.*	*Base*	*Opti.*
2013	3,710,489	3,976,370	3,989,150	688	693	731	735	760	778
2018	5,759,215	6,090,136	7,394,079	1,012	1,057	1,172	1,051	1,102	1,214
2023	9,216,566	9,617,281	9,706,566	1,542	1,603	1,617	1,582	1,649	1,660
2028	9,287,248	9,778,266	9,947,574	1,556	1,634	1,669	1,597	1,682	1,712

Table 4.18
Optimistic/Pessimistic Economy
Rural System

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Pessimistic	*Base*	*Optimistic*	*Pess.*	*Base*	*Opti.*	*Pess.*	*Base*	*Opti.*
2013	2,330,124	2,342,123	2,354,716	494	496	499	507	510	513
2018	2,246,498	2,320,926	2,399,499	495	512	529	509	526	543
2023	2,296,026	2,437,959	4,626,715	506	537	972	521	552	988
2028	2,355,290	2,570,163	4,850,719	518	566	1,021	534	583	1,038

Weather Scenarios – Rural system energy and peak demand is weather sensitive. The impact of weather on industrial customers and projected replacement load is insignificant. Under extreme weather conditions, rural system energy is projected to be 5% higher than normal, and peak demand is projected to be approximately 8% higher than normal. The impact of extreme weather conditions on winter peak demands is approximately one and one-half times greater than the impact on summer peak demand.

Table 4.19
Mild/Extreme Weather
Total Requirements (Native, HMP&L, Replacement)

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Mild	*Base*	*Extreme*	*Mild*	*Base*	*Extreme*	*Mild*	*Base*	*Extreme*
2013	3,902,304	3,976,370	4,111,957	631	693	783	734	760	812
2018	6,009,934	6,090,136	6,226,199	945	1,057	1,097	1,043	1,102	1,121
2023	9,535,736	9,617,281	9,755,403	1,486	1,603	1,644	1,587	1,649	1,668
2028	9,680,213	9,778,266	9,904,391	1,512	1,634	1,679	1,617	1,682	1,702

Table 4.20
Mild/Extreme Weather
Rural System

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Mild	*Base*	*Extreme*	*Mild*	*Base*	*Extreme*	*Mild*	*Base*	*Extreme*
2013	*2,268,057*	*2,342,123*	*2,475,731*	*425*	*496*	*578*	*494*	*510*	*571*
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Environmental Scenarios – Two scenarios were developed to demonstrate the impact of Big Rivers' environmental plan, which will impact consumption through changes in the price of electricity. Case 1 includes environmental related costs with the exception of Cross State Air Pollution Rule ("CSAPR") and carbon. Case 2 includes CSAPR but excludes carbon. Carbon related costs are addressed in the Carbon Tax forecast scenario. Under Case 1, the retail price of electricity to the rural class is projected to be [redacted] than the projected price in the base case. Under Case 2, the range increases to [redacted] than the base case. Under Case 1, energy and peak demand requirements are approximately [redacted] than the base case. In Case 2, energy and peak demand requirements are approximately [redacted] than the base case.

Table 4.21
Environmental Case 1/Case 2
Total Requirements (Native, HMP&L, Replacement)

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Case 1	*Base*	*Case 2*	*Case 1*	*Base*	*Case 2*	*Case 1*	*Base*	*Case 2*
2013	*3,976,370*	*3,976,370*	*3,976,370*	*693*	*693*	*693*	*760*	*760*	*760*
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Carbon Tax Scenarios- Big Rivers' base case load forecast assumes that current laws and regulations remain in effect through 2028. To investigate the impacts of a potential carbon tax, an analysis was performed using the results of a comprehensive study completed by the EIA. The study examined, in part, the impacts on energy consumption of potential policies that would limit energy-related carbon dioxide emissions.[48] More specifically, the impacts of a future fee on CO_2 emissions were analyzed for three carbon-fee cases, \$10, \$20, and \$30 per metric ton of CO_2 in 2020 and rising by 5 percent per year

[48] Energy Information Administration, *Further Sensitivity Analysis of Hypothetical Policies to Limit Energy-Related Carbon Dioxide Emission*, Supplement to the Annual Energy Outlook 2013, July 2013. http://www.eia.gov/forecasts/aeo/supplement/co2/pdf/aeo2013_supplement.pdf

annually thereafter. Whereas the EIA study assumes carbon tax scenarios beginning in 2014, Big Rivers reflects the impacts beginning in 2020, which Big Rivers concludes is a more reasonable start date.[49]

The EIA study was conducted at the national level and for each Census region. Big Rivers used the study results for the East South Central region. EIA reports that the electricity sector alters investment and operating decisions to reduce CO_2 emissions in response to CO_2 fees, and customers react to resulting higher retail electricity prices by cutting demand. An analysis of the changes in electricity prices and energy consumption for the three carbon-fee cases relative to the EIA reference case was performed, and the elasticity of demand (energy consumption) with respect to price for the residential and commercial sectors combined was -0.21. The average elasticity value derived from Big Rivers' load forecasting models for the rural system is -0.18. Since the elasticities are nearly the same for both the EIA study and Big Rivers' load forecast, Big Rivers concluded that the percent reductions in energy consumption relative to the reference case for each of EIA's potential policy cases are reasonable estimates for Big Rivers in estimating the potential impacts for Big Rivers power requirements.

Results of the carbon tax scenario analysis reveal that Big Rivers' native system sales could be approximately [redacted] than the base case forecast by 2028 if a $30 per metric ton of CO_2 policy was implemented, which is similar to the impacts estimated by EIA for the East South Central region of the country[50]. The same potential policy may impact rural system and industrial class energy requirements by approximately [redacted], respectively, over the same period, assuming the industrial class is capable of responding to price increases, which Big Rivers believes is unlikely.

Table 4.22
$10 per Ton/$30 per Ton

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	$10/Ton	*Base*	*$30/Ton*	*$10/Ton*	*Base*	*$30/Ton*	*$10/Ton*	*Base*	*$30/Ton*
2013	*3,976,370*	*3,976,370*	*3,976,370*	*693*	*693*	*693*	*760*	*760*	*760*
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[49] 2013 Carbon Dioxide Price Forecast, Synapse Energy Economics, Inc., November 1, 2013.

[50] Energy Information Administration, *Further Sensitivity Analysis of Hypothetical Policies to Limit Energy-Related Carbon Dioxide Emission*, Supplement to the Annual Energy Outlook 2013, July 2013. http://www.eia.gov/forecasts/aeo/supplement/co2/pdf/aeo2013_supplement.pdf

4.8 Research and Development

Big Rivers conducts residential surveys periodically to monitor changes in household major appliances and various end-uses. This schedule is expected to continue in future years. Results from the surveys are used to develop key inputs for the load forecasting models.

Big Rivers will continue to utilize end-use data and information obtained from its appliance saturation studies, along with data available from the EIA and any other sources that may become available in the future.

Big Rivers will continue to review and test alternative forecasting model methodologies and model specifications. It is anticipated that statistically adjusted end-use models will be used to forecast average use per customer. Big Rivers will also evaluate developing models at the individual customer class level in addition to the higher level rural system and direct serve categories.

Big Rivers assists its three Members in evaluating the potential impacts of new energy efficiency and demand response programs. Big Rivers continues to monitor potential load management and other demand response type programs.

5. Demand-Side Management

The DSM analysis for the 2014 IRP is based on an updated market potential study for energy efficiency and demand response measures. The potential study covers years 2014 through 2023. The results of the study have been incorporated in this IRP to update the analysis of the existing Big Rivers' DSM portfolio of programs. New measures have been incorporated into the analysis of existing programs, but no new programs have been added to the portfolio. Section 5.1 provides an overview of the results of the study, and Appendix B provides the full study.

5.1 Market Potential Study – Energy Efficiency

The DSM Potential Study examines the potential to reduce electric consumption and peak demand through the implementation of energy efficiency technologies and practices in residential, commercial, and industrial facilities. The study assessed energy efficiency potential throughout Big Rivers Members' service territories over ten years, from 2014 through 2023.

The study had five primary objectives:

- Develop measure databases of energy efficiency and demand response measures in the residential and non-residential sectors. The measure databases reflect current industry knowledge of energy efficiency and demand response measures, account for known codes and standards, and align with the market and demographics of Big Rivers Members' customers to the extent possible;
- Evaluate the electric energy efficiency technical potential savings in Big Rivers Members' territories;
- Calculate the Total Resource Cost ("TRC") test and Utility Cost Test ("UCT") benefit-cost ratios (among others) for potential electric energy efficiency measures; determine the electric energy efficiency economic potential savings (using the TRC test) for Big Rivers Members;
- Evaluate the potential for achievable savings through electric efficiency programs over a ten-year horizon (2014-2023); and
- Estimate the potential savings over a ten-year period from the delivery of a portfolio of energy efficiency programs based on a specific funding level. The portfolio of energy efficiency programs has been designed based on a total incentive budget of $1 million in 2014. The incentive budget of $1 million in 2014 aligns with current Big Rivers incentive budgets and is consistent with Big Rivers' three most recent rate cases, in which the Commission approved the inclusion of the $1 million DSM incentive budget in the calculation of Big Rivers' rates. At the direction of Big Rivers' staff, GDS also produced a sensitivity of potential savings at an incentive budget of $2 million.

Table 5.1 demonstrates the results of the energy efficiency potential study.

Table 5.1
2023 Summary Results of Energy Efficiency Potential Study

	MWh	*% of 2023 MWh Sales*	*Winter MW*	*% of 2023 Winter Peak*	*Summer MW*	*% of 2023 Summer Peak*
Technical Potential	*1,227,010*	*37.2%*	*177*	*27.1%*	*256*	*37.8%*
Economic Potential	*1,106,964*	*33.6%*	*169*	*25.9%*	*192*	*28.3%*
Achievable Potential	*368,891*	*11.2%*	*65*	*10.0%*	*64*	*9.5%*
Program Potential $2 mill.	*109,776*	*3.3%*	*12*	*1.8%*	*18*	*2.7%*
Program Potential $1 mill.	*53,686*	*1.6%*	*7*	*1.1%*	*8*	*1.2%*

All Sectors Combined

This study concludes that significant cost effective savings remain available in Big Rivers Members' territories. Table 5.2 shows the present value benefits, costs and benefit-cost ratios for the Achievable Potential scenario and the two Program Potential scenarios examined in this study.

Table 5.2
Benefit-Cost Ratios by Scenario Estimated by the Energy Efficiency Potential Study

Scenarios	*NPV $ Benefits*	*NPV $ Costs*	*Benefit/Cost Ratio*	*Net Benefits*
Achievable Potential	*$506,791,256*	*$236,486,056*	*2.14*	*$270,305,200*
Program ($ 2 million)	*$114,112,784*	*$50,901,486*	*2.24*	*$63,211,298*
Program ($ 1 million)	*$56,970,960*	*$25,432,384*	*2.24*	*$31,538,576*

Based on the results of the achievable potential analysis, and based on a review of energy efficiency programs currently offered, Big Rivers plans on continuing funding for the following energy efficiency programs as part of its DSM portfolio:

Residential Programs

1) Residential Lighting Program
2) Residential Efficient Appliances Program
3) Residential HVAC Program
4) Residential Weatherization Program
5) Residential New Construction Program
6) Residential HVAC Tune-Up Program

Commercial/Industrial Energy Efficiency Programs

7) C&I Lighting Program
8) C&I HVAC Program
9) C&I General Program

These programs represent the end-uses and equipment that held significant opportunities for cost-effective savings in the residential and commercial/industrial sector[51] and align with current Big Rivers DSM offerings. GDS provided an overview of existing energy efficiency programs, the target market, eligible energy efficiency measures, and proposed financial incentives for participants.

It is important to note that the potential savings, benefits, and costs presented in this section are a subset of the achievable potential. The objective of the calculation of program potential is to estimate what could be achieved given specific funding levels, specifically those shown in Table 5-3. This summary is not intended to represent specific future program designs, and is not based on actual or approved budgets in future years.

GDS also provided the potential savings, benefits, and costs for these programs assuming a $1 million incentive budget in 2014.[52] Estimated budgets in future years are a function of the estimated incremental annual achievable potential savings in future years. Actual energy and demand savings and program costs will depend upon many factors, including actual program funding levels and Member participation in the DSM programs offered by Big Rivers. Table 5.3 shows the estimated annual budgets for the $1 million incentive scenario for the residential and commercial/industrial sector. The allocation of incentive spending across sectors assumes that approximately two-thirds of the spending will be allocated towards the residential sector, with the balance going to the C&I sector. This assumption aligns with actual Big Rivers DSM results in recent years.

Table 5.3
$1 Million Scenario – Annual Incentive Budgets by Sector

	Residential	*Commercial / Industrial*	*Total*
2014	*$666,667*	*$329,403*	*$996,069*
2015	*$699,845*	*$337,791*	*$1,037,636*
2016	*$719,760*	*$347,284*	*$1,067,044*
2017	*$737,355*	*$355,473*	*$1,092,829*
2018	*$754,102*	*$363,744*	*$1,117,846*
2019	*$776,231*	*$371,715*	*$1,147,947*
2020	*$799,398*	*$380,469*	*$1,179,867*
2021	*$822,972*	*$389,271*	*$1,212,243*
2022	*$839,780*	*$398,153*	*$1,237,933*
2023	*$859,139*	*$407,910*	*$1,267,049*
2014-2023	***$7,675,248***	***$3,681,214***	***$11,356,462***

5.1.1 Residential Energy Efficiency Program Potential Scenarios

Six program potential scenarios for the residential sector are discussed below. These discussions focus on the $1 million incentive scenario, and the incentives and savings estimated for each program. More

[51] Commercial and industrial customers served under Big Rivers' Standard Rate Schedule RDS – Rural Delivery Service ("Big Rivers' Rural Delivery Service Tariff").

[52] GDS also evaluated a $2 million incentive budget sensitivity in 2014. The results of this evaluation are provided in the full report included in Appendix B.

detailed discussions of the programs which focus on the measures included in the programs and the estimated administrative costs are located in Appendix B, DSM Potential Study.

Residential Lighting Program

Big Rivers offers a residential lighting replacement program to its Members. This program promotes distribution of CFL bulbs by providing reimbursement to Members who purchase CFL bulbs. GDS recommends that the Residential Lighting Program continue to offer rebates for CFLs and also begin to offer rebates for LED bulbs. LED bulbs are increasing in cost-effectiveness due to rapidly dropping retail prices and are expected to gain an increased market share in the next several years.

Table 5.4 shows the estimated impacts of the Residential Lighting Program in the $1 million incentive scenario. The table provides the estimated impacts in the first year (2014) as well as the total impacts across a 10-year period. The $100,000 incentive budget in 2014 for the $1 million scenario aligns with current Big Rivers budget estimates for the program. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost[53].

Table 5.4
Residential Lighting Program – $1 Million Scenario

Residential Lighting Program	*2014*	*2014-2023 Totals*
Total Budget	*$157,143*	*$945,802*
Incentive Budget	*$100,000*	*$601,874*
Admin Budget	*$57,143*	*$343,928*
Cumulative Annual Participants	*14,682*	*140,644*
Total Annual kWh	*526,152*	*3,107,649*
Winter Peak kW	*171*	*987*
Summer Peak kW	*63*	*364*

Residential Efficient Appliances Program

Big Rivers offers multiple residential efficient appliances programs to its Members. The programs promote installation of efficient clothes washers and refrigerators and the removal and recycling of older inefficient refrigerators. For this study, GDS combined efficient clothes washers, efficient refrigerators and refrigerator recycling measures into a consolidated Residential Efficient Appliances program.

Table 5.5 shows the estimated impacts of the Residential Efficient Appliances Program in the $1 million incentive scenario. The table provides the estimated impacts in the first year (2014) as well as the total impacts across a 10-year period. The $150,000 incentive budget in 2014 for the $1 million scenario aligns with current Big Rivers budget estimates for the program. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost.

[53] The residential lighting program potential scenario assumes a 35% incentive (instead of 100% incentives) because the measure mix is largely comprised of LED bulbs, which are more expensive than CFL bulbs. The residential weatherization program potential scenario assumes that CFL bulbs will continue to be distributed during site visits at no cost to Members.

Table 5.5:
Residential Efficient Appliances Program – $1 million scenario

Residential Efficient Appliances	*2014*	*2014-2023 Totals*
Total Budget	*$207,988*	*$2,093,138*
Incentive Budget	*$150,000*	*$1,508,437*
Admin Budget	*$57,988*	*$584,700*
Cumulative Annual Participants	*2,030*	*11,983*
Total Annual kWh	*775,025*	*6,475,637*
Winter Peak kW	*120*	*1,055*
Summer Peak kW	*147*	*1,293*

Residential HVAC Program

Big Rivers offers a residential HVAC replacement program to its Members. This program promotes increased use of high efficiency HVAC systems among the retail members of the Member cooperatives by providing reimbursement to Member cooperative members for upgrading their HVAC systems.

Table 5.6 shows the estimated impacts of the Residential HVAC Program in the $1 million incentive scenario. The table provides the estimated impacts in the first year (2014) as well as the total impacts across a 10-year period. The $90,000 budget in 2014 for the $1 million scenario aligns with current Big Rivers budget estimates for the program. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost.

Table 5.6
Residential HVAC Program – $1 Million Scenario

Residential HVAC Program	*2014*	*2014-2023 Totals*
Total Budget	*$141,429*	*$3,522,547*
Incentive Budget	*$90,000*	*$2,241,621*
Admin Budget	*$51,429*	*$1,280,926*
Cumulative Annual Participants	*733*	*2,242*
Total Annual kWh	*505,715*	*10,794,150*
Winter Peak kW	*50*	*1,070*
Summer Peak kW	*8*	*222*

Residential Weatherization Program

Big Rivers offers a residential weatherization program to its Members. This program promotes the implementation of weatherization measures among the retail members of the Member cooperatives by providing reimbursement to Member cooperative members for undertaking weatherization improvements at their homes.

Table 5.7 shows the estimated impacts of the Residential Weatherization Program in the $1 million incentive scenario. The table provides the estimated impacts in the first year (2014) as well as the total impacts across a 10-year period. The budget of approximately $206,000 in 2014 for the $1 million scenario is approximately aligned with current Big Rivers budget estimates for the program.

The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost for the stand-alone insulation measures and 100% of the incremental cost for the full weatherization package measures.

Table 5.7:
Residential Weatherization Program – $1 Million Scenario

Residential Weatherization Program	*2014*	*2014-2023 Totals*
Total Budget	*$257,417*	*$2,566,907*
Incentive Budget	*$205,667*	*$2,050,618*
Admin Budget	*$51,750*	*$516,289*
Cumulative Annual Participants	*86*	*864*
Total Annual kWh	*246,696*	*2,215,470*
Winter Peak kW	*80*	*667*
Summer Peak kW	*73*	*468*

Residential New Construction Program

Big Rivers offers a residential new construction program to its Members. This program provides incentives to home owners and builders to use energy efficient building standards as outlined in the Touchstone Energy® certification program.

Table 5.8 shows the estimated impacts of the Residential New Construction Program in the $1 million incentive scenario. The tables provide the estimated impacts in the first year (2014) as well as the total impacts across a 10-year period. The $100,000 budget in 2014 for the $1 million scenario aligns with current Big Rivers budget estimates for the program. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost.

Table 5.8:
Residential New Construction Program – $1 Million Scenario

Residential New Construction	*2014*	*2014-2023 Totals*
Total Budget	*$157,143*	*$1,629,731*
Incentive Budget	*$100,000*	*$1,037,102*
Admin Budget	*$57,143*	*$592,630*
Cumulative Annual Participants	*80*	*829*
Total Annual kWh	*204,233*	*2,120,243*
Winter Peak kW	*38*	*391*
Summer Peak kW	*28*	*291*

Residential HVAC Tune-Up Program

Big Rivers offers a residential HVAC tune-up replacement program to its Members. This program promotes the initiation of annual maintenance on heating and air conditioning equipment among the retail members of the Member cooperatives by providing reimbursement to Member cooperative retail members that have their heating and cooling systems professionally cleaned and serviced.

Table 5.9 shows the estimated impacts of the Residential HVAC Tune-up Program in the $1 million incentive scenario. The table provides the estimated impacts in the first year (2014) as well as the total impacts across a 10-year period. The $21,000 budget in 2014 for the $1 million scenario aligns with current Big Rivers budget estimates for the program. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost.

Table 5.9
Residential HVAC Tune-Up Program – $1 Million Scenario

Residential HVAC Tune-up Program	*2014*	*2014-2023 Totals*
Total Budget	*$33,000*	*$370,223*
Incentive Budget	*$21,000*	*$235,596*
Admin Budget	*$12,000*	*$134,626*
Cumulative Annual Participants	*375*	*2,180*
Total Annual kWh	*177,359*	*1,030,913*
Winter Peak kW	*55*	*320*
Summer Peak kW	*70*	*405*

5.1.2 Commercial and Industrial Energy Efficiency Program Potential Scenarios

Three program potential scenarios for the commercial and industrial sector[54] are discussed below. The discussions focus on in the $1 million incentive scenario, and the incentives and savings estimated for each program. More detailed discussions of the programs which focus on the measures included in the programs and the estimated administrative costs are located in Appendix B, DSM Potential Study.

Commercial and Industrial Prescriptive Lighting Program

Big Rivers offers a prescriptive lighting replacement program, including outdoor lighting, to its Members' commercial and industrial members. This program provides an incentive to commercial and industrial retail member consumers for whom service is taken under Big Rivers' Rural Delivery Service Tariff to upgrade poorly designed and low efficiency lighting systems.

Table 5.10 shows the estimated impacts of the Commercial and Industrial Prescriptive Lighting Program in the $1 million incentive scenario. The tables provide the estimated impacts in the first year (2014) as well as the total impacts across a 10-year period. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost.

[54] Commercial and industrial customers served under Big Rivers' Rural Delivery Service Tariff.

Table 5.10
Commercial and Industrial Prescriptive Lighting Program – $1 Million Scenario

C&I Prescriptive Lighting Program	*2014*	*2014-2023 Totals*
Total Budget	*$256,108*	*$2,867,665*
Incentive Budget	*$204,886*	*$2,294,132*
Admin Budget	*$51,222*	*$573,533*
Cumulative Annual Participants	*3,803*	*41,268*
Total Annual kWh	*1,564,051*	*2,699,129*
Winter Peak kW	*133*	*252*
Summer Peak kW	*211*	*399*

Commercial and Industrial Prescriptive HVAC Program

Big Rivers offers a prescriptive HVAC program to its Members' commercial and industrial members. This program provides an incentive to commercial and industrial retail member consumers to upgrade inefficient HVAC equipment and to maintain and tune-up their existing equipment.

Table 5.11 shows the estimated impacts of the Commercial and Industrial Prescriptive HVAC Program in the $1 million incentive scenario. The table provides the estimated impacts in the first year (2014) as well as the total impacts across a 10-year period. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost.

Table 5.11
Commercial and Industrial Prescriptive HVAC Program – $1 Million Scenario

C&I Prescriptive HVAC Program	*2014*	*2014-2023 Totals*
Total Budget	*$71,998*	*$787,267*
Incentive Budget	*$57,599*	*$629,814*
Admin Budget	*$14,400*	*$157,453*
Cumulative Annual Participants	*436*	*4,739*
Total Annual kWh	*457,813*	*521,167*
Winter Peak kW	*30*	*32*
Summer Peak kW	*179*	*207*

Commercial and Industrial Prescriptive General Program

Big Rivers offers a general program to its Members' commercial and industrial members. This program provides an incentive to retail commercial and industrial retail members served under the Big Rivers' Rural Delivery Service Tariff to upgrade all aspects of cost-effective energy efficiency achievable in individual facilities.

Table 5.12 shows the estimated impacts of the Commercial and Industrial Prescriptive Lighting Program in the $1 million incentive scenario. The table provides the estimated impacts in the first year (2014) as well as the total impacts across a 10-year period. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost.

Table 5.12
Commercial and Industrial General Program – $1 Million Scenario

C&I General Program	*2014*	*2014-2023 Totals*
Total Budget	*$83,648*	*$946,585*
Incentive Budget	*$66,918*	*$757,268*
Admin Budget	*$16,730*	*$189,317*
Cumulative Annual Participants	*621*	*6,722*
Total Annual kWh	*564,572*	*904,274*
Winter Peak kW	*70*	*99*
Summer Peak kW	*82*	*133*

5.1.3 Three-Year Summary

The scope of the market potential study (the DSM Potential Study provided in Appendix B of this 2014 IRP) included calculating the achievable energy efficiency potential across a 10-year timeframe. The results of the potential study are useful for long-term planning efforts as well as developing short-term program planning efforts. Table 5.13 provides a three-year summary of the $1 million incentive scenario. The three-year summary is useful for understanding the estimated energy efficiency potential across the same time horizon as the three-year action plan discussed in Section 1.8. The incentive budgets are assumed to increase each year for inflation. This incentive increase is a function of the achievable potential calculation. If incentive budgets are held at $1,000,000 each year across the three-year timeframe from 2014-2016, then the estimates of achievable energy and demand savings would be slightly less than shown in Table 5-13 below.

Table 5.13
Three Year Summary – $1 Million Scenario

ALL PROGRAMS COMBINED	*2014*	*2015*	*2016*
Cumulative Annual MWh Savings	*5,022*	*10,311*	*15,823*
Cumulative Annual Winter MW Savings	*0.75*	*1.53*	*2.33*
Cumulative Annual Summer MW Savings	*0.86*	*1.75*	*2.65*
Incentives	*$996,069*	*$1,037,636*	*$1,067,044*
Administrative	*$369,803*	*$390,859*	*$404,612*
Total Big Rivers	***$1,365,872***	***$1,428,495***	***$1,471,656***

5.2 Market Potential Study – Demand Response

Section 5.1 discusses the overall objectives and results of the market potential study. The study focused on energy efficiency programs, but also included an evaluation of possible demand response programs in Big Rivers' territory. This section provides a brief overview of the results of the demand response analysis. Chapter 8 of the market potential study provides a more complete discussion of the demand response analysis. The full study can be found in Appendix B, DSM Potential Study.

5.2.1 Current Demand Response Programs

Big Rivers does not currently operate any direct control programs and does not provide electric service to any retail or wholesale customers under an interruptible or curtailable contract or tariff, except that Big Rivers offers a Voluntary Curtailment Rider, which provides a means for potentially reducing system peak demand during peak periods. In the last ten years, there have been four curtailments affecting two commercial customers. The maximum estimated load reduction due to the two voluntary curtailment customers is 20-25 MW.

5.2.2 Demand Response Programs Evaluated

A list of potential demand response programs representing the most common and most likely to be cost-effective were evaluated in this screening analysis. Refer to Table 5.14. A more comprehensive list was not originally screened because the expectation for cost effectiveness for demand response was low given the low value associated with avoided peaking capacity. Therefore, Big Rivers focused the analysis on the most common types of programs that a utility might use in starting a demand response initiative. If more of these programs passed the screening, the list of potential programs for screening would have been expanded. Programs not included initially, but that could have been considered if further analysis was warranted include, but are not limited to: dual fuel heat pumps, electric thermal storage ("ETS") heating units for residences, ETS cooling units for commercial buildings, direct control of swimming pool pumps, and direct control of agricultural applications such as irrigators and grain dryers.

Table 5.14
Demand Response Programs Evaluated Results

Sector	*Program*	*Basis*	*Peak Effect*	*Direct Control*	*Summer kW Savings per Unit*	*Winter kW Savings per Unit*
Residential	*Air Conditioner - 33% Cycling*	*Incentive*	*Peak Shift*	*Yes*	*0.8*	*0.0*
	Air Conditioner - 50% Cycling	*Incentive*	*Peak Shift*	*Yes*	*1.1*	*0.0*
	Water Heater - 40/50 Gallon	*Incentive*	*Peak Shift*	*Yes*	*0.4*	*0.6*
	Time-of-Use (TOU) Rate	*Price*	*Peak Shift*	*No*	*0.2*	*0.1*
	Critical Peak Pricing (CPP) Rate	*Price*	*Peak Shift*	*No*	*1.0*	*0.5*
	Smart Thermostat w/ CPP Rate	*Incentive/Price*	*Peak Shift*	*Yes*	*1.4*	*0.5*
Commercial	*Distributed Generation*	*Incentive*	*Peak Clip*	*Yes*	*350*	*350*
	Lighting - Small Application	*Incentive*	*Peak Clip*	*Yes*	*2.1*	*2.1*
	Lighting - Large Application	*Incentive*	*Peak Clip*	*Yes*	*21*	*21*
	Energy Management System (EMS)	*Incentive*	*Peak Shift*	*No*	*12*	*12*
	Time-of-Use (TOU) Rate	*Price*	*Peak Shift*	*No*	*0.1*	*0.1*
	Critical Peak Pricing (CPP) Rate	*Price*	*Peak Shift*	*No*	*0.6*	*0.6*
Industrial	*Distributed Generation*	*Incentive*	*Peak Clip*	*Yes*	*1,000*	*1,000*
	Energy Management System (EMS)	*Incentive*	*Peak Shift*	*No*	*150*	*150*
	Interruptible Rate	*Price*	*Peak Clip*	*No*	*1,000*	*1,000*

A total of fifteen programs were evaluated, with a mix of both residential and commercial incentive-based and price-based programs. Consistent with the energy efficiency evaluation, demand response programs are primarily evaluated based on the Total Resource Cost test, but Utility Cost Test and Participant Costs Tests ("PCT") were also calculated.

5.2.3 Conclusions for Demand Response

With Big Rivers and the region in and around MISO having sufficient capacity, the value of demand response programs is presently low, even lower than determined in the 2010 DSM Potential Study. Furthermore, there are no benefits associated with avoided transmission facilities at this time. Therefore, it is not surprising that most of the demand response programs analyzed do not pass the TRC test. The following programs did pass the TRC test.

Commercial Lighting Control Large Application – This program passes the TRC test, but only by a very small margin. The benefit cost ratio is 1.02. These programs require intrusive installation such as wiring to individual fixtures throughout a building so that fixtures can be controlled by the utility. This would not be an ideal first program for demand response, but may be considered and pursued by a utility with a mature demand response portfolio and extensive experience in installation of control switches.

Interruptible Rate – This program can be very impactful with very little cost. That is because the assumption is that the industrial customer is able to curtail 1 MW without additional equipment. An interruptible program looks highly beneficial in many demand response studies even with low avoided cost benefits. Obviously, the challenge to the utility is finding candidates that meet these stringent criteria and that would be willing to either change shifts or operations in order to reduce their power bills.

Conclusion – GDS' analysis indicated most of the typical demand response programs analyzed in the screening are not cost-effective at this time, and those that are cost effective are either difficult to implement or are only marginally cost effective. GDS suggested that Big Rivers would be better served by using its DSM budget to pursue higher value energy efficiency programs. However, as capacity tightens in the region, the value of capacity should increase, approaching the avoided cost of a peaking unit. At that time, demand response programs could become cost effective. Based on GDS' recommendations, Big Rivers will:

- Continue to pursue high value energy efficiency programs
- Not pursue a full scale demand response program at this time.
- Continue to monitor opportunities for demand response, looking for reduction in costs or increases in the value of avoided peaking generation.
- Monitor the opportunity of new technologies that may provide peak demand reduction benefits, including Smart Grid technologies.
- Work with the Members to evaluate benefits of interruptible rate arrangements to new or existing large commercial or industrial customers.

5.3 2013 DSM/Energy Efficiency Results

The 2013 DSM Program Summary is shown in Table 5.15. Total spending of $1,352,780 on incentives and promotion exceeded the target spend of $1.3 million by slightly more than $50,000. Promotion expenditures were 7.5% of the total cost.

Table 5.15
2013 DSM/Energy Efficiency Program Summary

		2013 Program Totals	
	Units	*Unit Quantity*	*Spend*
Residential Programs			
DSM-01 High Efficiency Lighting Replacement	*bulbs*	*75,074*	*$129,877*
DSM-02 Energy Star Clothes Washer Replacement	*unit*	*1,061*	*$106,100*
DSM-03 Energy Star Refrigerator Replacement	*unit*	*674*	*$67,400*
DSM-04 Residential High Efficiency HVAC	*unit*	*262*	*$92,850*
DSM-05/DSM-10 Residential Weatherization	*homes*	*168*	*$538,072*
DSM-06 Touchstone Energy New Home	*homes*	*83*	*$74,600*
DSM-07 Residential HVAC Tune-Up	*unit*	*556*	*$13,900*
Commercial/Industrial (C&I) Programs			
DSM-08 C&I High Efficiency Lighting	*kW saved*	*583*	*$204,073*
DSM-09 C&I General Energy Efficiency	*kW saved*	*0*	*$0*
DSM-07 C&I HVAC Tune-Up	*units*	*118*	*$5,900*
DSM-11 C&I High Efficiency HVAC	*ton*	*0*	*$0*
Other Programs			
DSM-12 High Efficiency Outdoor Lighting	*fixture*	*262*	*$18,340*
Promotion Expense			*$101,667*
Total			*$1,352,780*

The total budget for 2013 energy efficiency programs was $1,300,000; $300,000 above the $1 million collected in base rates. $300,000 was carried over from the 2012 budget when the entire $1 million was not spent.

Substantial modifications to the weatherization program were submitted for Commission approval on February 22, 2013, and the modified program was put on hold until the changes received Commission approval on June 6, 2013.[55] The $400,000 budget for the weatherization program was aggressive, but the popularity of the program quickly became apparent, and word of mouth resulted in a total spend of more than $538,000.

The Touchstone Energy New Home program continues to be popular among large tract developers in areas where natural gas is prevalent. Single home construction contractors are participating at a much

[55] *In the Matter of: Tariff Filing of Big Rivers Electric Corporation to Revise and Implement Demand-Side Management Programs*, Case No. 2013-00099.

lower rate. Members applied for 83 Touchstone Energy Home incentives, 17 short of the annual target of 100. The remaining budget was redirected to the weatherization program.

Both residential and commercial HVAC tune-up participation exceeded 2012 participation, but fell short of 2013 targets. The remaining 2013 budget was re-directed to the weatherization program, and targets for 2014 have been adjusted downward to reflect more realistic market demand.

Commercial lighting finished the year 12.5% above target. The second half of 2013 was very active for commercial members participating in this program.

No applications for non-lighting projects were received from commercial members under the General Energy Efficiency program.

The Commercial HVAC program was approved June 6, 2013, and promotional efforts were undertaken; however, no commercial members applied for the incentive. Capital investments of this type generally involve analysis and approval, and there is hope the program will become more active in 2014.

5.4 2013 Budget

The 2013 energy efficiency program budget included $1 million collected through rates and $300,000 carried over from the 2012 budget that was not spent. Table 5.16 shows the 2013 energy efficiency program participation and spending levels for each program. This table also quantifies the estimated impact of each target on energy consumption and peak demand.

The 2013 budget of $1,300,000 was split into two segments. The amount of $1,150,000 was targeted at incentives, while the remaining $150,000 was set aside for promotional efforts. Any promotional funds not consumed are available to support programs that attract high participation.

Specific program budgets are flexible and are tailored to retail member response to each program. The Member cooperatives are able to adjust or shift budgets to address successful programs.

Tables 5.16, 5.17, and 5.18 provide detailed program impact for years 2011, 2012 and 2013, respectively.

Table 5.16
2011 Program Spend and Impacts

Big Rivers 2011 DSM/Energy Efficiency Program Impact

Residential Programs	Per Unit Annual kWh Savings	Per Unit Winter kW Savings	Per Unit Summer kW Savings	Unit Quantity	Total Annual kWh Savings	Total Winter kW Savings	Total Summer kW Savings
Residential Lighting Program							
CFL bulbs	31	0.007	0.003	19743	605,320	141.0	61.9
Residential Efficient Appliances							
Clothes Washer Rebate	224	0.007	0.026	233	52,192	1.6	6.1
Energy Star Refrigerator + Recycling	1,084	0.076	0.089	79	85,636	6.0	7.0
HVAC Program							
Dual Fuel	3,448	7.066	0.146	31	106,888	219.1	4.5
Air Source Heat Pump	692	0.000	0.146	25	17,300	0.0	3.7
Goethermal	3,658	4.453	0.365	11	40,238	49.0	4.0
Weatherization Program							
Stick-Built Home	6,980	4.950	0.890	0	0	0.0	0.0
Manufactured Home	4,680	2.200	0.300	0	0	0.0	0.0
New Construction							
Gas Heat	2,435	0.260	0.580	0	0	0.0	0.0
Air Source Heat Pump	4,922	2.700	0.580	0	0	0.0	0.0
Dual Fuel Heat Pump (w/ Gas)	8,370	9.766	0.580	0	0	0.0	0.0
Geothermal Heat Pump	8,580	7.150	0.799	0	0	0.0	0.0
Tune-Up							
HVAC Tune-Up	636	0.000	0.304	0	0	0.0	0.0

Commercial/Industrial Programs	Annual kWh Savings Per $	Winter kW Savings Per $	Summer kW Savings Per $	Total kW Reduced	Total Annual kWh Savings	Total Winter kW Savings	Total Summer kW Savings
C&I Lighting							
Lighting Projects	12	0.0031	0.0029	48.6	198,677	48.6	45.4
C&I Products							
Misc. Efficient Projects	0	0	0	0.0	0	0.0	0.0

	Annual kWh Savings Per Unit	Winter kW Savings Per Unit	Summer kW Savings Per Unit	Unit Qty.	Total Annual kWh Savings	Total Winter kW Savings	Total Summer kW Savings
Tune-Up							
HVAC Tune-Up*	5,268	0.000	1.200	0	0	0.0	0.0

** Assumed 6 tons/unit*

Total DSM Program Savings:	**1,106,251**	**465.2**	**132.6**

Table 5.17
2012 Program Spend and Impacts

Big Rivers 2012 DSM/Energy Efficiency Program Impact

Residential Programs	Annual kWh Savings Per Unit	Winter kW Savings Per Unit	Summer kW Savings Per Unit	Unit Quantity	Total Annual kWh Savings	Total Winter kW Savings	Total Summer kW Savings
Residential Lighting Program							
CFL bulbs	31	0.007	0.003	51,792	1,587,943	369.8	162.4
Residential Efficient Appliances							
Clothes Washer Rebate	224	0.007	0.026	563	126,112	3.9	14.6
Energy Star Refrigerator + Recycling	1,084	0.076	0.089	383	415,172	29.1	34.1
HVAC Program							
Dual Fuel	3,448	7.066	0.146	33	113,784	233.2	4.8
Air Source Heat Pump	692	0.000	0.146	46	31,832	0.0	6.7
Goethermal	3,658	4.453	0.365	21	76,818	93.5	7.7
Weatherization Program							
Stick-Built Home	6,980	4.950	0.890	9	62,820	44.6	8.0
Manufactured Home	4,680	2.200	0.300	1	4,680	2.2	0.3
New Construction							
Gas Heat	2,435	0.260	0.580	67	163,145	17.4	38.9
Air Source Heat Pump	4,922	2.700	0.580	2	9,843	5.4	1.2
Dual Fuel Heat Pump (w/ Gas)	8,370	9.766	0.580	0	0	0.0	0.0
Geothermal Heat Pump	8,580	7.150	0.799	2	17,159	14.3	1.6
Tune-Up							
HVAC Tune-Up	636	0.000	0.304	260	165,360	0.0	79.0

Commercial/Industrial (C/I) Programs	Annual kWh Savings Per $	Winter kW Savings Per $	Summer kW Savings Per $	Total kW Reduced	Total Annual kWh Savings	Total Winter kW Savings	Total Summer kW Savings
C&I Lighting							
Lighting Projects	#REF!	#REF!	#REF!	418	1,710,419	418.4	390.9
C&I Products							
Misc. Efficient Projects	#REF!	#REF!	#REF!	31	76,446	5.8	30.8
	Annual kWh Savings Per Unit	Winter kW Savings Per Unit	Summer kW Savings Per Unit	Unit Quantity	Total Annual kWh Savings	Total Winter kW Savings	Total Summer kW Savings
Tune-Up							
HVAC Tune-Up*	5,268	0.000	1.200	77	405,636	0.0	92.4
** Assumed 6 tons/unit*							
				Total DSM Program Savings:	4,967,169	1,237.6	873.3

Table 5.18
2013 Program Spend and Impacts

Big Rivers Program/Measure Assumptions

2013 DSM/Energy Efficiency Program Impact

Residential Programs	Units	Annual kWh Savings Per Unit	Winter kW Savings Per Unit	Summer kW Savings Per Unit	Unit Quantity	Total Annual kWh Savings	Total Winter kW Savings	Total Summer kW Savings
Residential Lighting Program								
CFL bulbs	bulbs	31	0.007	0.003	75,074	2,301,769	536.0	235.4
Residential Efficient Appliances								
Clothes Washer Rebate	unit	224	0.007	0.026	1,061	237,664	7.4	27.4
Energy Star Refrigerator + Recycling	unit	1,084	0.076	0.089	674	730,616	51.2	60.0
HVAC Program								
Dual Fuel	unit	3,448	7.066	0.146	64	220,672	452.2	9.3
Air Source Heat Pump	unit	692	0.000	0.146	159	110,028	0.0	23.2
Goethermal	unit	3,658	4.453	0.365	39	142,662	173.7	14.2
Weatherization Program								
Wx - Wgt Average Of 4 measures	homes	5,703	2.917	0.583	168	958,094	490.1	98.0
New Construction								
Gas Heat	homes	2,435	0.260	0.580	68	165,580	17.7	39.4
Air Source Heat Pump	homes	4,922	2.700	0.580	4	19,686	10.8	2.3
Dual Fuel Heat Pump (w/ Gas)	homes	8,370	9.766	0.580	3	25,109	29.3	1.7
Geothermal Heat Pump	homes	8,580	7.150	0.799	8	68,636	57.2	6.4
Tune-Up								
HVAC Tune-Up	unit	636	0.000	0.304	556	353,616	0.0	168.8

Commercial/Industrial (C/I) Programs		Annual kWh Savings Per Unit	Winter kW Savings Per Unit	Summer kW Savings Per Unit	Total kW Reduced	Total Annual kWh Savings	Total Winter kW Savings	Total Summer kW Savings
C&I Lighting								
Lighting Projects	kW saved	4088	1.000	0.9300	583	2,383,304	583.0	542.2
C&I Products								
Misc. Efficient Projects	kW saved	3666	1.000	1.0000	0	0	0.0	0.0
		Annual kWh Savings Per Unit	Winter kW Savings Per Unit	Summer kW Savings Per Unit	Unit Quantity	Total Annual kWh Savings	Total Winter kW Savings	Total Summer kW Savings
Tune-Up								
HVAC Tune-Up*	Units	860	0.000	0.570	118	101,480	0.0	67.3
HVAC Replacement Program								
HVAC ROB Program	ton	135	0.000	0.100	0	0	0.0	0.0

OTHER		Annual kWh Savings Per $	Winter kW Savings Per $	Summer kW Savings Per $	Unit Quantity	Total Annual kWh Savings	Total Winter kW Savings	Total Summer kW Savings
Efficient Outdoor Lighting								
100W MH to LED	fixture	250	0.037	0.002	262	65,526	9.8	0.5
100W MH to Induction	fixture	131	0.020	0.001	0	0	0.0	0.0
Totals						7,884,442	2,418	1,296

6. Transmission Planning

The Big Rivers' transmission system consists of the physical facilities necessary to transmit power from its generating plants and interconnection points to all substations from which customers of its three Members are served. Transmission planning embodies making investment decisions required to maintain this system so that it can reliably and efficiently meet the power needs of the customers served. Justifications used in any transmission study and subsequent projects are based on technical and economic evaluations of options that may be implemented to meet the specific need. Transmission improvement projects are designed to meet all industry standards including those set forth by North American Electric Reliability Corporation NERC and the Southeast Electric Reliability Corporation ("SERC").

6.1 MISO Transmission Planning

As a member of MISO, Big Rivers participates in MISO's coordinated short and long-term planning processes. The transmission system expansion plans established for MISO and its member companies must ensure the reliable operation of the transmission system, support achievement of state and federal energy policy requirements, and enable a competitive energy market to benefit all customers. The planning process, in conjunction with an inclusive stakeholder process, must identify and support development of transmission infrastructure that is sufficiently robust to meet local and regional reliability standards, and enable competition among wholesale energy suppliers. The Guiding Principles of the MISO Transmission Expansion Planning ("MTEP") process follow:

- Guiding Principle 1: Make the benefits of an economically efficient energy market available to customers by identifying transmission projects that provide access to electricity at the lowest total electric system cost.
- Guiding Principle 2: Provide a transmission infrastructure that meets all applicable NERC and Transmission Owner planning criteria and safeguards local and regional reliability through identification of transmission projects to meet those needs.
- Guiding Principle 3: Support state and federal energy policy requirements by planning for access to a changing resource mix.
- Guiding Principle 4: Provide an appropriate cost allocation mechanism that ensures that costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects.
- Guiding Principle 5: Analyze system scenarios and make the results available to state and federal energy policy makers and other stakeholders to provide context and to inform choices.
- Guiding Principle 6: Coordinate transmission planning with neighboring planning regions to seek more efficient and cost-effective solutions.

6.2 Transmission Transfer Capability

Big Rivers routinely assesses its transmission system's ability to transfer power into and out of Big Rivers' local balancing area. Additionally, Big Rivers performs transfer capability studies as a participant in MISO and SERC seasonal assessments. While transfer capability values can vary significantly due to a number of factors, study results (simultaneous net import capability of approximately 900 MW) demonstrate that Big Rivers can import sufficient generation to satisfy all firm system demand requirements. Further, the existing transmission system is sufficient to support the export of all Big Rivers' generation power greater than the amount required to serve native load.

6.3 Transmission System Optimization and Expansion

With respect to the improvement and more efficient utilization of existing Big Rivers transmission facilities during the period from 2009 through August of 2014, Big Rivers constructed and placed in service approximately 0.3 miles of new 69 kV transmission line to serve seven new delivery point substations of its Members. An additional 20 miles of 69 kV and 6 miles of 161 kV lines were constructed to strengthen the transmission network and thus improve reliability.

To increase transmission line current ratings, approximately 7 miles of 69 kV and 28 miles of 161 kV lines were reconductored with higher current capacity conductors. A new 345 kV interconnect between Big Rivers' existing Reid EHV substation and Vectren Corporation's A. B. Brown substation was energized at no cost to Big Rivers' Members. With the addition of this new 345 kV line, Big Rivers now has two high voltage transmission lines at the Reid EHV substation, which greatly improves the ability to transfer power both in and out of Big Rivers' transmission system.

Additionally, Kentucky Utilities Company ("KU") and Big Rivers are completing the construction necessary to loop an existing Big Rivers'-owned 161 kV circuit through the new KU Matanzas substation in Ohio County, Kentucky. The first phase of the project was energized on December 12, 2013. This phase created a new high voltage 161 kV transmission interconnect between Big Rivers' Wilson substation in Centertown, Kentucky, and KU's new Matanzas substation in Ohio County, Kentucky. When complete, the second phase of the project will result in a second Big Rivers' 161 kV interconnect to the KU Matanzas substation. The second phase is expected to be energized in January 2016.

Big Rivers upgraded its microwave communications infrastructure with the expansion of the East and West loops picking up the three Members plus a new broadband digital microwave overbuild addition to all three power plant locations for voice and data networking needs providing high speed network connectivity.

Big Rivers has completed the replacement of the two-way radio system for Big Rivers and its three Members. Each of the four companies now operates its own two-way radio system, with the radio systems sharing a common backbone infrastructure. This new system accommodates two-way radio communications among the four companies during emergency situations.

Work toward completion of other transmission system improvements is a continuous process. A list of completed and planned improvements to the Big Rivers' system for the 2009-2028 time period is presented in Tables 6.1 and 6.2.

Table 6.1
Completed System Additions (2009 - 2014)

Project Description	*Year*
Olivet Church Rd. 69 kV line addition	*2009*
Reid – Daviess Co. 161 kV reconductor	*2009*
Coleman – Coleman EHV 161 kV line 1 reconductor	*2010*
Coleman – Coleman EHV 161 kV line 2 reconductor	*2010*
Coleman – Newtonville 161 kV line reconductor	*2010*
Armstrong Dock 69 kV Service	*2010*
Equality 69 kV Service	*2010*
Falls of Rough – McDaniels 69 kV line addition	*2010*
Cannelton 69 kV Service	*2011*
Lewis Creek 69 kV Service	*2011*
Wilson 161 kV terminal for new tap line	*2011*
Wilson 161/69 kV transformer addition	*2012*
Wilson – Centertown 69 kV line	*2012*
Meade – Garrett 69 kV line reconductor	*2012*
Garrett – Flaherty 69 kV line project	*2013*
Riveredge 69 kV Transmission Service	*2013*
Maxon 69 kV Service	*2013*
Elk Creek 69 kV Transmission Service	*2013*
Wilson – KU Matanzas 161 kV line	*2014*

Table 6.2
Planned System Additions (2014 – 2028)

Project Description	*Year*
Paradise 161 kV reconductor from new tap point	*2014*
Buttermilk 69 kVService	*2014*
Cumberland – Caldwell Springs 69 kV line	*2014*
Hancock County 69 kV mobile capacitor bank	*2014*
White Oak 161/69 kV substation addition	*2015*
Irvington Substation switching & metering	*2015*
Meade County 161/69 kV transformer replacements (2)	*2015*
West Owensboro 69 kV reconductor	*2016*
KU Matanzas – New Hardinsburg/Paradise 161 kV tap line	*2016*
Wilson – Sacramento 69 kV line addition	*2018*
Thruston Junction – East Owensboro 69 kV reconductor	*2018*
Rome Junction – Philpot Tap 69 kV reconductor	*2018*
HMP&L Sub 4 161/69 kV transformer addition	*2018*

7. MISO Resource Adequacy Planning

Big Rivers joined MISO on December 1, 2010, to meet its NERC-mandated Contingency Reserve requirements. By joining MISO and signing the MISO Transmission Owners Agreement, Big Rivers is obligated to follow MISO's FERC-approved tariff. Per the Commission's order approving Big Rivers' request to join MISO in Case No. 2010-00043,[56] Big Rivers retained an obligation to regularly file an IRP for Commission review, detailing Big Rivers' load, determining appropriate reserve requirements, and identifying sources of energy, demand-side resources, and projected need for new generation and transmission facilities.

7.1 MISO's Resource Adequacy Mechanism Overview (Module E-1)

One of MISO's resource planning principles is to maintain system reliability in operating and planning horizons while providing the lowest costs. MISO's resource adequacy mechanism, implemented in 2009, has three primary components: a footprint-wide planning reserve margin, standardized resource qualifications, and facilitation of Load Serving Entity ("LSE") compliance requirements.

- Planning Reserve Margin ("PRM") - MISO's broad-focused PRM aims to produce significant annual customer benefits through diversity and generation availability.
- Resource Qualification - include testing, measurement, verification, availability data (forced outage rates), performance requirements and obligations.
- Compliance Requirements - MISO monitors planning compliance. A LSE found deficient is assessed an administrative penalty. LSE is an industry term commonly used to describe utilities or others who provide electric service to customers.

7.2 MISO Resource Adequacy Planning

Module E-1 (Resource Adequacy) of MISO's tariff[57] provides forward transparent capacity pricing signals, recognizes congestion that limits aggregate deliverability and complements state resource planning processes. Each year, MISO performs studies to evaluate current market conditions to forecast future planning environments. The Loss of Load Expectation ("LOLE") study is performed annually to set the minimum Planning Reserve Margin for the upcoming planning year and provide a nine (9) year Planning Reserve Margin forecast.

Annual Planning Resource Auction (PRA)

The annual capacity auction construct described in MISO Module E-1 allows Market Participants to achieve resource adequacy and allows for transparency. MISO's location-specific approach used in the Planning Resource Auction ("PRA") is intended to provide efficient price signals to encourage the appropriate resources to participate in the locations where they provide the most benefit. This

[56] *In the Matter of: Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of its Transmission System to Midwest Independent Transmission System Operator, Inc.*, Case No. 201 0-00043. Subsequent to this proceeding, MISO changed its name from Midwest Independent Transmission System Operator, Inc., to Midcontinent Independent System Operator, Inc.
[57] https://www.misoenergy.org/Pages/Home.aspx

methodology creates a variety of options for LSEs to obtain the resources required to meet their PRM requirements, including Fixed Resource Adequacy Plans, bilateral transactions, self-scheduling, capacity deficiency payments, and auction purchases.

Module E Capacity Tracking Tool (MECT)

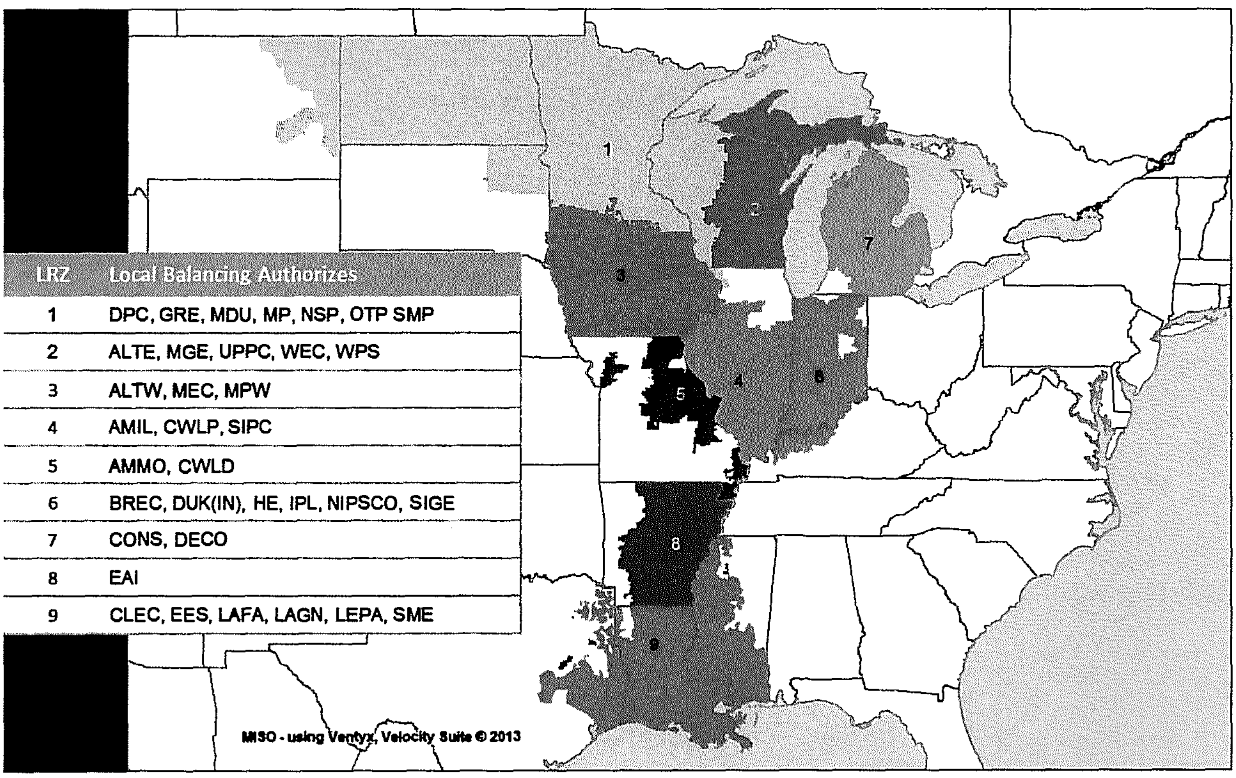
Market Participants submit demand forecast information, qualify resources, track bilateral capacity transactions, designate capacity to meet their Planning Reserve Margin requirements, and participate in the PRA using the Module E Capacity Tracking Tool.

2013 Loss of Load Expectation Study

MISO conducts an annual Loss of Load Expectation study to determine a Planning Reserve Margin, Unforced Capacity ("PRM (UCAP)"), zonal per-unit Local Reliability Requirements, Capacity Import Limits and Capacity Export Limits. The results of the study and its deliverables supply inputs to the MISO Planning Resource Auction, including the local Planning Reserve Margin requirement.

Big Rivers is located in MISO's regional zone 6, along with entities in Indiana, as shown in Figure 7.1.

Figure 7.1
MISO Region Map



In accordance with the MISO tariff, the reliability objective of a LOLE study is to determine a minimum PRM that would result in the MISO system experiencing a less than one day loss of load event every 10 years. The MISO analysis for 2014 shows that the system would achieve this reliability level when the amount of installed capacity available is 1.148 times that of the MISO system coincident peak. This equates to a 14.8% Planning Reserve Margin requirement for 2014/2015 based on installed capacity ("ICAP").

LOLE Process for Planning Year 2014-2015

In compliance with Module E-1 of the MISO tariff, MISO performed its annual LOLE study to determine the Planning Reserve Margin on an unforced capacity basis for the MISO system and the per-unit Local Reliability Requirements of Local Resource Zone ("LRZ") Peak Demand for the planning year 2014-2015.

LOLE Modeling Input Data and Assumptions

MISO utilizes a program developed by General Electric called Multi-Area Reliability Simulation ("GE MARS") to calculate the LOLE for the applicable planning year. GE MARS uses a sequential Monte Carlo simulation to model a generation system and assess the system's reliability based on any number of interconnected areas. GE MARS calculates the annual LOLE for the MISO system and each Local Resource Zone by stepping through the year chronologically and taking into account generation, load, load modifying and energy efficiency resources, equipment forced outages, planned and maintenance outages, load forecast uncertainty and external support.

Many cases of GE MARS models are built to model different scenarios and to determine how certain variables impact the results. The base case models determine the MISO PRM (ICAP), PRM (UCAP) and the LRR for each LRZ for year one, and forward years five and 10.

MISO utilizes existing systems and data for many of the GE MARS inputs, including MISO's Power Generating Availability Data System ("GADS") for unit-specific information such as Generator Verification Test Capacities ("GVTC"), Monthly Net Dependable Capacities, Unit Forced Outage Rates (EFORd and XEFORd as defined by IEEE 762), and Planned Maintenance Factor (average number of events and duration). The GVTC values, along with the monthly NDC values, are used to determine the capacity profile for each unit. Forced outage rates and planned maintenance factors were calculated over a five-year period (January 2008 to December 2012) and modeled as one value. Generating units that had filed suspensions or retirements (as of June 5, 2013) through MISO's Attachment Y process and were approved are accounted for in the LOLE analysis.

MISO Load Data

For the 2014-2015 LOLE analysis, the hourly LRZ load shape was a product of the historical load shape used as well as the 50/50 demand forecasts submitted by the LSEs through the MECT tool.

The non-coincident peak demand forecasts (with transmission losses) by LSEs were aggregated by their respective Local Balancing Authorities ("LBA") and applied to the LBA's historical load shape in GE MARS. LRZs 1 through 7 used the 2005 historical load shape while zones 8 and 9 (the new MISO South region) used the 2006 historical load shape. For MISO Midwest (the portion of MISO not including the new MISO South region), the 2005 load shape provides a typical load shape for the Midwest region as well as inherent conservative external support due to external load shapes. With the integration of MISO South, MISO chose to use the 2006 historical shape as the 2005 shape represented an extreme weather year for the South region due to Hurricane Katrina.

Load Forecast Uncertainty

Load Forecast Uncertainty ("LFU"), a standard deviation statistical coefficient, is applied to base 50/50 load forecast to represent the various probabilistic load levels. With transition into Module E1 in 2012, MISO determines two separate requirements: Local Reliability Requirement for each zone as well as an overall MISO-wide Planning Reserve Margin.

MISO's analysis method enabled modeling of each LRZs demand and generation uniquely, and the derivation of a MISO-wide PRM that aligns with the zonal construct using the same model and applying the same zonal LFUs for both footprint-wide and zonal calculations.

External System

The LOLE study utilized an external model with seven external zones. To determine an appropriate level of support that MISO could expect from the external systems, each external zone was modeled at its appropriate target PRM with adjustments for sales/purchases and DSM program reductions. The tie capacity value to each external zone was derived from an analysis of the 2012 Historical Net Scheduled Interchange data. The LOLE model probabilistically determines reasonable external assistance and reduction in the PRM from being interconnected to external entities.

Loss of Load Expectation Analysis and Metric Calculations

Once the GE MARS input files were created, MISO determined the appropriate PRM (ICAP) and PRM (UCAP) for the 2014-2015 Planning Year as well as the appropriate Local Reliability Requirement for each of the nine LRZ's. These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year.

Planning Year 2014-15 Results

For the 2014-2015 planning year, MISO had more than enough capacity to meet a LOLE of 0.1 days per year. In order to achieve a LOLE of 0.1 days per year, unforced capacity had to be removed from the MISO pool. This was done following an iterative process of removing the units with the smallest unforced capacity until MISO reached a LOLE of 0.1 days per year. The last unit removed was not completely removed but derated to a point where the reliability criterion was met.

The formulas for the PRM values for the MISO system are:

PRM (ICAP) = ((Installed Capacity + Firm External Support + ICAP Adjustment to meet a LOLE of 0.1 days per year) – MISO Coincident Peak Demand))/MISO Coincident Peak Demand

PRM (UCAP) = ((Unforced Capacity + Firm External Support + UCAP Adjustment to meet a LOLE of 0.1 days per year) – MISO Coincident Peak Demand))/MISO Coincident Peak Demand

Where UCAP = ICAP x (1 – XEFORd)

For the 2014-2015 planning year, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning installed capacity reserve margin of 14.8 percent and a planning unforced capacity reserve margin of 7.3 percent. These PRM values assume 3,103 MW UCAP of firm and 1,899 MW UCAP of non-firm external support. Table 7.1 shows the footprint-wide values and the calculations that went into determining the MISO system PRM (ICAP) and PRM (UCAP).

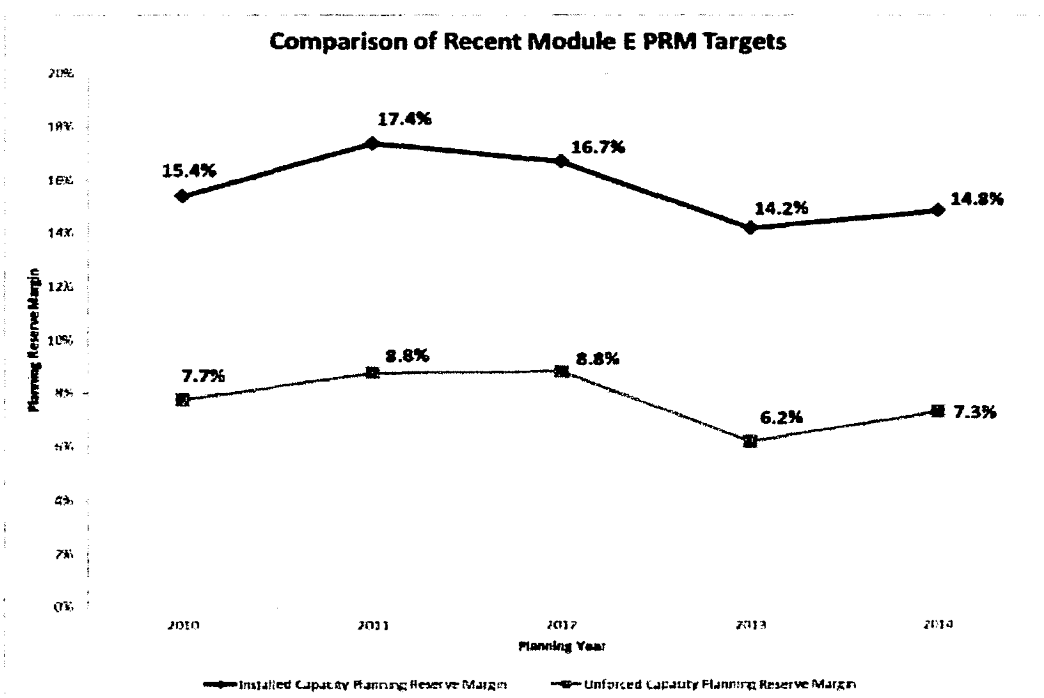
Table 7.1
MISO Planning Reserve Margin (PRM)

MISO Planning Reserve Margin (PRM)	2014/2015 PY (June 2014 - May 2015)	Formula Key
MISO System Peak Demand (MW)	125,453	[A]
Time of System Peak (EST)	8/5/2014 17:00	
Installed Capacity (ICAP) (MW)	170,847	[B]
Unforced Capacity (UCAP) (MW)	146,961	[C]
Firm External Support (MW)	3,103	[D]
Adjustment to ICAP (MW)	-29,875	[E]
Adjustment to UCAP (MW)	-15,452	[F]
ICAP PRM Requirement (PRMR) (MW)	144,075	[G]=[B]+[D]+[E]
UCAP PRM Requirement (PRMR) (MW)	134,612	[H]=[C]+[D]+[F]
MISO PRM ICAP	14.8%	[I]=([G]-[A])/[A]
MISO PRM UCAP	7.3%	[J]=([H]-[A])/[A]

Comparison of PRM Targets across Five Years

Figure 8.1 below compares the PRM (ICAP) and PRM (UCAP) values over the last five planning years. The last endpoints of the black and green lines show the planning year 2014-2015 PRM values.

Figure 7.2
Comparison of Recent module E PRM Targets



Future Years 2015 through 2023 Planning Reserve Margins

Beyond the planning year 2014-2015 LOLE study analysis, a LOLE analysis was performed for the five-year-out planning year of 2018-2019 and the 10-year-out planning year of 2023-2024. The PRM (ICAP) and PRM (UCAP) results are shown as the red-font values of Table 7.2. The years in between were arrived at through interpolation of the results from the years 2014, 2018 and 2023. Note that the MISO system PRM results assume no limitations on transfers within MISO.

Table 7.2
MISO Planning Reserve Margin (PRM) 2018/2019 PY

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
PRM ICAP	14.8%	14.9%	15.0%	15.1%	15.1%	15.6%	16.0%	16.4%	16.8%	17.3%
PRM UCAP	7.3%	7.3%	7.2%	7.2%	7.2%	7.2%	7.3%	7.3%	7.3%	7.4%

Table 5.2-2: MISO System Planning Reserve Margins 2014 through 2023

In future years, MISO sees stability in the PRM (UCAP), which is driven by MISO's assumption of constant Load Forecast Uncertainty in out years. The increasing characteristic of the PRM (ICAP) is an outcome of the adjustment methodology sensitivity to installed capacity levels of generation and the removal of units needed to reach 0.1 days per year LOLE target level. Smaller UCAP units, such as Wind and Behind-the-Meter Generation, are often the first units removed or last units added in the adjustment. In the future years, fewer and fewer of these units are being removed to reach the target LOLE. Since the difference in the ICAP to UCAP rating of these units is greater than the average unit in the system the PRM (ICAP) is increasing in the future years.

7.3 Big Rivers' consideration of MISO Planning Reserve Margins in this IRP

Big Rivers' reserve margin study showed reserve margins in excess of MISO's 2023 requirement (17.3% ICAP) over the 15-year IRP forward planning period. Big Rivers will continue to comply with MISO's tariff requirements, which includes the possibility for varying amounts of planning reserves. As the MISO market evolves, Big Rivers will continue to evaluate the proper reserve margin target. Big Rivers continues to participate in MISO Resource Adequacy Working Groups, Loss of Load Expectation Working Group, and other groups, to ensure Big Rivers' participation in the MISO market provides optimum value to its Members.

8. Environmental

The Big Rivers' system consists of seven coal-fired units of various size and vintage, and one combustion turbine ("CT"). Big Rivers also operates and has the contractual right to certain amounts of the capacity and energy from two coal- fired units owned by HMP&L. Table 8.1 identifies the operating units:

Table 8.1
Environmental Controls on Existing Units

Unit	*Net Capacity*	*Commercialized*	*SO2 Control*	*NOx Control*
R.A. Reid 1	*65 MW*	*1966*	*See below*	*See below*
K.C. Coleman 1	*150 MW*	*1969*	*FGD Retrofit in 2006*	*Over-fired Air*
K.C. Coleman 2	*138 MW*	*1970*	*FGD Retrofit in 2006*	*Over-fired Air*
K.C. Coleman 3	*155 MW*	*1972*	*FGD Retrofit in 2006*	*Over-fired Air*
Henderson 1	*153 MW*	*1973*	*FGD Retrofit in 1995*	*SCR Retrofit in 2004*
Henderson 2	*159 MW*	*1974*	*FGD Retrofit in 1995*	*SCR Retrofit in 2004*
R.D. Green 1	*231 MW*	*1979*	*FGD*	*Coal re-burn*
R.D. Green 2	*233 MW*	*1981*	*FGD*	*Cool re-burn*
D.B. Wilson	*417 MW*	*1986*	*FGD*	*SCR Retrofit in 2004*
R.A. Reid CT	*65 MW*	*1976*	*See below*	*See below*

Big Rivers has applied for a Title V permit revision to convert Reid Unit 1 to natural gas as part of its efforts to comply with EPA Mercury and Air Toxics Standards ("MATS").

The Reid CT fuel oil unit was retrofitted to burn natural gas (as well as fuel oil) in 2001 for Sulfur Dioxide ("SO_2") and Nitrous Oxides ("NOx") control.

8.1 Clean Air Regulations – Cross State Air Pollution Rule and Clean Air Interstate Rule)

EPA proposed the Cross State Air Pollution Rule to replace the Clean Air Interstate Rule ("CAIR") that was previously vacated by federal courts on July 11, 2008. CSAPR requires 23 states to reduce annual SO_2 and NOx emissions to help downwind areas attain the 24-hour and/or Annual PM 2.5 National Ambient Air Quality Standards ("NAAQS"). Twenty-five states are required to reduce ozone seasonal NOx emissions to help downwind areas attain the 1997 8-hour Ozone NAAQS. The rule addresses all up-wind states' transport obligations under the 1997 annual PM 2.5 and 2006 24-hour PM 2.5 standards. For 14 states, it will also address upwind state transport obligations under the 1997 ozone NAAQS. For the rest of the upwind states covered by the CSAPR ozone program, the rule provides emission reductions while EPA continues to evaluate additional emission reductions.

The final CSAPR regulations divided the states required to reduce SO_2 into two groups. CSAPR originally envisioned both groups reducing their SO_2 emissions beginning in 2012. Group 1 states were required to make additional reductions in SO_2 emissions two years later in order to eliminate their significant contribution to air quality problems in downwind areas. Kentucky is a Group 1 state.

The D.C. Circuit Court vacated CSAPR in August 2012, leaving CAIR as the program controlling SO_2 and NOx emissions. The U.S. Solicitor General petitioned the Supreme Court to review the D.C. Circuit Court's decision on CSAPR. The U.S. Supreme Court accepted the review of CSAPR. On April 29, 2014, the

Supreme Court ruled in favor of the EPA, upholding the CSAPR program and remanding the case back to the lower court for further action.

At this time, it is unknown what actions EPA will take. Big Rivers will continue to monitor these developments and adjust its compliance strategy accordingly. If EPA implements CSAPR in its original form prior to it being vacated in 2012, it appears that CSAPR will not have a significant impact on Big Rivers' operations (based upon original allowance allocations) as the Coleman Station has been idled. When Coleman is returned to service, further system wide NOx reductions could be required. For this IRP, Big Rivers has modeled the estimated costs associated with an SCR at Green in 2019 in Environmental Case 2 in anticipation of this.

Both CAIR and CSAPR are similar in function in that allowances are provided to utilities. The main difference between the two programs is the restriction in the CSAPR trading program. CAIR allowances can be traded to any utility in any quantity, whereas CSAPR allowances are restricted to a geographical area and are limited depending upon the location of the utility.

NOx - Big Rivers previously installed SCRs on Wilson Station and HMP&L Units 1 and 2 and low NOx burners at Coleman and Green. The Coleman Units also utilize over-fired air for NOx control. Coleman Unit 1 NOx control differs from Units 2 and 3 with the addition of a separate air source for NOx control, rather than the combustion source. Green Units 1 and 2 have a coal re-burn system in place to reduce NOx emissions through the injection of coal at the top end of the boiler furnace.

NOx allowances issued under CAIR are surrendered at a rate of one allowance for each ton of NOx emitted for both the annual program, which runs January 1 to December 31, and the seasonal program, which runs from May 1 to September 30. Historically, Big Rivers has had insufficient allocations of annual NOx allowances to cover its emissions. Big Rivers purchases allowances each year to meet this shortfall, which is about 8% lower than typical emissions. The allocations of seasonal NOx allowances are typically equal to the emissions.

SO_2 - Big Rivers currently utilizes Flue Gas Desulfurization Systems (or scrubbers) on all its coal fired units except Reid 1.

SO_2 allowances issued under CAIR are currently surrendered at a rate of 2 allowances for every ton of SO_2 emitted. The ratio changes from the current surrender rate of 2 to 1 to 2.86 to 1 in 2015. Big Rivers currently has a sufficient bank of SO_2 allowances to offset its emissions. When the CAIR program is replaced in the future, the banked allowances will not be permitted to be transferred to the new program.

In the production of this IRP, estimated costs associated with the operation of the FGD, SCR, ACI and DSI systems were included in all cases, with the exception of Coleman ACI and DSI which are not in the base case.

8.2 Mercury and Air Toxics Standards

The Mercury and Air Toxics Standards regulations became effective April 2012 with a compliance date of April 16, 2015. The regulations allow a one year extension if granted by the appropriate state regulatory agency.

The MATS rule finalizes standards to reduce air pollution from coal and oil-fired power plants under Sections 111 (new source performance standards) and 112 (toxics program) of the 1990 Clean Air Act. Emissions standards set under the MATS rule are federal air pollution limits that individual facilities must meet by a set date. EPA must set emission standards for existing sources as stringent as the emission reductions achieved by the average of the top 12 percent best controlled sources.

These rules establish technology-based emissions limitation standards for mercury, non-mercury metals (filterable particulate material (FPM) can be used as a surrogate), and acid gases (either hydrogen chloride (HCl) or SO_2). The final rules apply to coal and oil –fired electric generating units ("EGUs") with a capacity of 25 megawatts or greater.

Existing sources generally will have up to 4 years to comply with MATS. This includes the 3 years provided to all sources by the Clean Air Act as well as an additional year that state permitting authorities can grant for technology installation.

Big Rivers submitted an Environmental Compliance Plan in 2011 as part of its PSC proceedings to request a Certificate of Public Convenience and Necessity ("CPCNs") for MATS compliance. This plan included activated carbon injection (ACI) systems and dry sorbent injection (DSI) systems for its Green, Wilson and Coleman plants.

Several rounds of testing were conducted at Big Rivers' units to determine if control equipment would be needed to meet the requirements of MATS. Coleman Station and Green Station were identified as needing additional control equipment. Wilson Station was identified as requiring DSI equipment. HMP&L Station 2, which has an SO_2 scrubber and a SCR to control NOx was shown to meet compliance. Reid Station is scheduled to be converted to burn natural gas, which will exempt the unit from further MATS compliance.

Big Rivers is currently procuring and installing ACI and DSI systems on its Green Units 1 and 2. Burns and McDonnell was hired to the develop plans and specifications for the Green Station units. The control equipment for the Green units are expected to be in service in early 2015. In addition, monitoring equipment to verify compliance will be installed at Green, Wilson and HMP&L stations.

Due to the planned idling of both Wilson and Coleman Stations, Big Rivers will request a one-year extension of the MATS compliance date to April 2016 for these units through the Kentucky Division for Air Quality. Since the Coleman Station has been idled, the installation of control equipment and monitors will be required before it is placed back into service. IRP Environmental cases 1 and 2 include the estimated costs associated with MATS compliance at Coleman.

8.3 Coal Combustion Residuals (CCR)

Coal Combustion Residuals ("CCRs") are residues from the combustion of coal and include fly ash, bottom ash, and scrubber waste. CCRs are currently exempted from the requirements of the Resource Conservation and Recovery Act ("RCRA"); however, CCRs are regulated by Kentucky as Special Wastes. In 2010, EPA proposed two options for regulating CCRs under RCRA: (1) as hazardous waste under Subtitle C, and (2) as non-hazardous waste under Subtitle D.

Under Subtitle C (hazardous waste designation), existing surface impoundments must remove solids, meet land disposal restrictions, and have a liner installed within five years of the effective date of the regulation. This requirement would effectively phase out use of existing surface impoundments due to the land disposal restrictions of the ash. New surface impoundments must meet the liner and land disposal restriction as well, which would effectively phase out the construction of new impoundments. Existing landfills will require groundwater monitoring and liner installation for any horizontal expansion. The main difference between the Subtitle C and Subtitle D requirement is the removal of the land disposal restriction for Subtitle D.

EPA has announced that it will issue the final rule in December 2014. At this time, it is expected that EPA will regulate CCRs under Subtitle D based on comments EPA made in the preamble of the Effluent Limitation Guidelines ("ELG"). The expectations are that the CCR program and the ELG program will have the same implementation timeline.

Big Rivers operates two special waste landfills, one located next to the Green Station and one located at the Wilson Station. Both landfills have groundwater monitoring as required by the proposed regulation; however, both landfills will likely require liners under the remaining air space after the regulation is finalized.

Big Rivers operates three facilities that utilize ash ponds, Coleman Station, Green Station and Reid Station. Depending upon the final regulation, the ash ponds will likely be required to be lined or the units converted to dry ash handling systems. Preliminary estimated costs associated with converting to dry ash systems to comply with CCR regulations are included in Environmental Cases 1 and 2 in 2019 for this IRP.

8.4 Steam Effluent Guidelines (ELG)

The current effluent guidelines and standards for steam electric power, which were last updated in 1982, do not adequately address the changes in control technology according to the EPA. Generally, the proposed rule would establish new or additional requirements for wastewater streams from the following processes and by products associated with steam electric power generation: flue gas desulfurization, fly ash, bottom ash, and flue gas mercury control.

The proposed national standards are based on data collected from industry and provide flexibility in implementation through a phased-in approach and use of technologies already installed at a number of plants. Under the proposed approach, new requirements for existing power plants would be phased in between 2017 and 2022.

The proposed ELG regulation lists eight options (see Table 8.2) for controlling discharges from seven waste streams. Within the eight options EPA has identified, EPA believes four preferred options (Options 3a, 3b, 3, and 4a) are economically achievable. Of those four options, only three would potentially apply to Big Rivers due to the unit size requirement in Option 3b. The Best Available Technology Economically Achievable ("BAT") for each option is proposed for each waste stream. The first preferred option (Option 3a) includes:

- Zero Discharge effluent limits for all pollutants in fly ash transport water and wastewater from flue gas mercury controls systems;
- Numeric effluent limits for copper and iron discharges of nonchemical metal cleaning wastes; and
- Effluent limits for bottom ash transport water and combustion residual leachate from landfills and surface impoundments that are equal to current Best Professional Judgment ("BPJ") effluent limits for these discharges (i.e., numeric effluent limits for total suspended solids ("TSS") and oil and grease).

Under Option 3, all of the proposed requirements in Option 3b would be included. In addition, numeric effluent limits for mercury, arsenic, selenium, and nitrate-nitrite in the discharges of FGD wastewaters would be established.

Under Option 4a, EPA would establish zero discharge effluent limits for all pollutants in bottom ash transport water, as well as retaining all of the requirements in Option 3.

EPA is expected to finalize the ELG regulations in 2014, and the impact to Big Rivers is expected in the 2017 to 2020 time frame depending upon the timing of the issuance of the Kentucky Pollution Discharge Elimination System ("KPDES") permits. Preliminary estimated costs for complying with ELG are included in IRP Environmental Cases 1 and 2 in 2019.

Table 8.2[58]
EPA Options for ELG Compliance

Waste Stream	Pollutants for Regulation	BAT for the main regulatory options (white options are identified as preferred)							
		1	3a	2	3b	3	4a	4	5
FGD Wastewater	Oil and Grease TSS Arsenic Mercury Nitrate/nitrite Selenium	Chemical Precipitation	BPJ Determination	Chemical Precipitation + Biological Treatment	[1]Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Evaporation
Fly Ash Transport Water	Oil and Grease TSS *Zero Discharge	Impoundment (equal to BPT)	*Dry Handling	Impoundment (equal to BPT)	*Dry Handling	*Dry Handling	*Dry Handling	*Dry Handling	*Dry Handling
Bottom Ash Transport Water	Oil and Grease TSS *Zero Discharge	Impoundment (equal to BPT)	Impoundment (equal to BPT)	Impoundment (equal to BPT)	Impoundment (equal to BPT)	Impoundment (equal to BPT)	[2]*Dry Handling/ Closed Loop	*Dry Handling/ Closed Loop	*Dry Handling/ Closed Loop
Combustion Residual Leachate	Oil and Grease TSS Arsenic Mercury	Impoundment (equal to BPT)	Impoundment (equal to BPT)	Impoundment (equal to BPT)	Impoundment (equal to BPT)	Impoundment (equal to BPT)	Impoundment (equal to BPT)	Chemical Precipitation	Chemical Precipitation
Gasification Wastewater	TDS Arsenic Mercury Selenium	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation
Flue Gas Mercury Control Wastewater	Oil and Grease TSS *Zero Discharge	Impoundment (equal to BPT)	*Dry Handling	Impoundment (equal to BPT)	*Dry Handling	*Dry Handling	*Dry Handling	*Dry Handling	*Dry Handling
Nonchemical Metal Cleaning Wastes	Oil and Grease TSS Copper Iron	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation

* For some options, EPA is proposing to establish zero discharge limitations rather than establish numerical discharge limits on pollutants of concern

[1]For Units at a facility with a total wet-scrubbed capacity of > 2,000 MW. Best Professional Judgment (BPJ) for < 2,000 MW.

[2]For Units > 400 MW. Impoundment (equal to BPT) for units < 400 MW.

8.5 Clean Water Act, Section 316(b)

Section 316(b) of the Clean Water Act addresses cooling water intake structures that have sufficient velocity to impinge and entrain aquatic organisms. There are three components to the proposed regulation. First, existing facilities that withdraw at least 25 percent of their water from an adjacent water body exclusively for cooling purposes and have a design intake flow of greater than 2 million gallons per day would be subject to an upper limit on how many fish can be killed by being pinned

[58] From Federal Register 40 CFR 423 (http://www.ecfr.gov/cgi-bin/text-idx?SID=c8f5b984be77f7a614a244626ce18c4b&node=40:30.0.1.1.23&rgn=div5).

against intake screens or other parts at the facility (impingement). The facility would determine which technology would be best suited to meeting this limit. Alternately, the facilities could reduce their intake velocity to 0.5 feet per second. At this rate, most of the fish can swim away from the cooling water intake of the facility.

Second, existing facilities that withdraw very large amounts of water, at least 125 million gallons per day, would be required to conduct studies to help their permitting authority determine whether and what site specific controls, if any, would be required to reduce the number of aquatic organisms pulled into cooling water systems (entrainment). This decision process would include public input.

Third, new units that add electrical generation capacity at an existing facility would be required to add technology that is equivalent to closed cycle cooling.

Big Rivers has two intake structures used for once through cooling of steam condenser tubes that meet the definition of this regulation. Coleman Station for the amount withdrawn from the river and the intake velocity, and Reid Station for the intake velocity. Big Rivers hired Sargent and Lundy to review the proposed regulation and provide a cost estimate to comply. Sargent and Lundy recommended the installation of fish pumps on the traveling screen as the modification that would meet the requirements of 316b impingement. Entrainment studies have not been completed and the associated costs have not been developed. The scope of the entrainment studies will be developed as a part of the renewal of the KPDES permit. Preliminary estimated costs for complying with this regulation are included in both IRP Environmental Cases 1 and 2 in 2019.

8.6 Greenhouse Gas (GHG)

EPA is expected to propose new regulations to reduce greenhouse gases ("GHG") for existing units in early 2014 and finalize them in early 2015. Planning a compliance strategy is problematic without the promulgation of regulations because of other provisions in the statute. Subsection (1) (B) states, "Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." This section does not offer a definition of useful life, and therefore, it will be up to the Commonwealth of Kentucky and the EPA to determine. Big Rivers' facilities' commercial operation dates range from 1966 to 1986.

Reductions beyond those that can be achieved through improvement in steam efficiency and generation efficiency could be very costly to achieve and could affect the long term viability of existing coal-fired units. However, dependent on rule specifics, it is possible that idling Coleman and/or Wilson station could enable Big Rivers to comply.

In an effort to estimate the impact of GHG regulations on the dispatch of Big Rivers' generating units and the consumption of Big Rivers Members' customers, two sensitivities were prepared in this IRP analysis. Please see Section 10.2 for a discussion of the sensitivities performed.

Table 8.3

Cost Data ($millions)*

ENVIRONMENTAL CASE 1					
Plant	**Regulation**	**Compliance Method**	**Projected Cap Ex 2018**	**Subtotal**	**Projected Incremental O&M 2019**
Coleman	MATS	ACI/DSI	[redacted]		
	CCR	Submerged Scraper Conveyors (SSC)			
	Effluent	FGD WWTF			
	Effluent	Dry Fly Ash			
	316b	Traveling Screens w/ fish return			
Green	Effluent	FGD WWTF			
	Effluent	Dry Economizer Ash			
	CCR	Submerged Scraper Conveyors (SSC)			
Reid	316b	Traveling Screens w/ fish return			
HMPL	CCR	Submerged Scraper Conveyors (SSC)		[REDACTED]	
ENVIRONMENTAL CASE 2					
Plant	**Regulation**	**Compliance Method**			
Add following to Case 1					
Green	CSAPR	SCR (1)			
Grand Total					

** All cost data in Table 8.3 is based on Big Rivers' current understanding of a number of pending regulations. These future projected expenditures are likely to change as requirements change, further information becomes available, and/or studies are updated.*

8.7 Summary

The multitude of potential environmental regulations presents significant challenges to all electric utilities going forward. In particular, the staggered compliance dates along with interaction between the Coal Combustion Residuals and Steam Effluent Guidelines regulations complicate compliance planning. Big Rivers will continue to monitor the potential environmental regulations, and as these regulations are finalized, Big Rivers will continue to update and evaluate its compliance options as more information becomes available.

While potential environmental regulations are pending, Big Rivers has made significant investments in pollution control equipment, which will be beneficial in continued compliance, as well as meeting future regulations.

Big Rivers is well positioned to meet future challenges that will be faced by all coal-fired generating stations. Big Rivers plans to evaluate the conversion of a portion of its existing coal-fired fleet to natural gas as an alternative to installing additional pollution control equipment at its Green and Coleman facilities. A focus on inventive ideas will continue to ensure the most cost-effective solutions are chosen to meet future challenges.

9. Supply-Side Analysis

This IRP presents Big Rivers' plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. In development of its 2014 IRP, Big Rivers has considered the impacts of a number of key variables and uncertainties. Furthermore, the plan includes an assessment of potentially cost-effective resource options.

Big Rivers' resource assessment was developed using the Strategist Integrated Planning System. This model, which is licensed to GDS Associates by Ventyx, has the capability to simulate production operations and develop least cost expansion plans. The production operations simulation establishes the optimal dispatch of generating resources and calculates the associated costs. The development of least-cost expansion plans includes comparisons of all combinations of potential resource additions to determine the portfolio of expansion units necessary to achieve planning reserve margin criteria at the lowest cost. Big Rivers' existing generating resources were modeled using the Strategist GAF module. The existing units were dispatched against the 2013 Load Forecast, which is described in full in Section 4 and Appendix A. The 2013 Load Forecast was modeled using the Strategist LFA module.

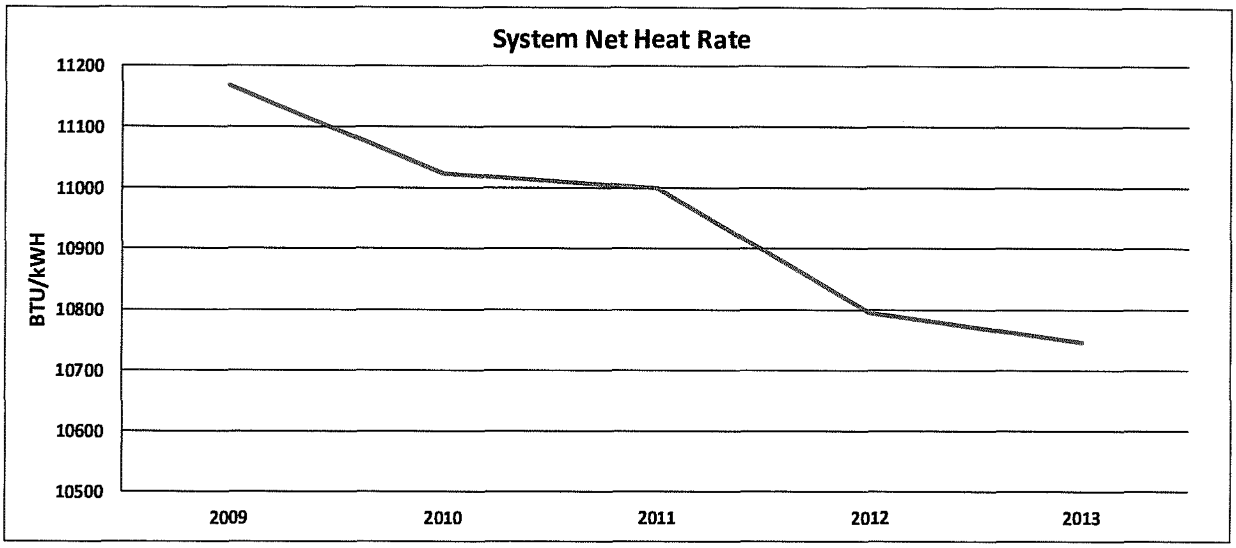
Big Rivers operates two units owned by HMP&L. These two units, HMP&L Station Two Units 1 and 2, were included at their full capacity values in the analysis. HMP&L's load and energy requirements, which are served by the Station Two capacity, were included in the analysis as part of Big Rivers' total load obligation, since HMP&L can vary its contracted portion of HMP&L Station Two annually. The net impact of this configuration is that capacity beyond that used to serve HMP&L requirements is available to serve Big Rivers' requirements. Similarly, HMP&L's SEPA allocation was included as a capacity resource, as it offsets the HMP&L load.

9.1 Generation Operations Update

Big Rivers' senior management places an emphasis on generation efficiency, and Big Rivers continues to make strides in generation efficiency improvements. For the Big Rivers system of the base load units, the heat rate has improved 420 BTU/kWh or 3.8% in the 4-year period from 2009 to 2013. Refer to Figure 9.1.

Figure 9.1
System Net Heat Rate

System Net Heat Rate			
Year	BTU/kWH		
2009	11,167		
2010	11,025		
2011	11,001	2009 to 2013 Improvement	
2012	10,795	BTU/kWH	%
2013	10,747	420	3.8%



Specific generation improvement activities include:

Operations Training Simulators: Big Rivers purchased Operations Training Simulators for Wilson, Green, HMP&L and Coleman Stations in 2011 and 2012 for training Control Room Operators ("CROs"). Well trained CROs have a significant impact on improving the generation efficiency of the units they are operating.

Controllable Losses: Controllable losses are operating variables (*i.e.*, condenser back pressure, excess oxygen, boiler exit gas temperature, etc.) that the CRO can influence (control) and that have an impact on generation efficiency. Monitors are available on a real time basis for the CROs and management to visually monitor controllable losses.

Maintenance: Maintenance activities remain focused on improving generation efficiency. During forced outages, the washing of air heaters, cleaning condenser tubes, replacing leaking valves and traps, and repairing air/gas leaks are some examples of tasks that are completed.

Instrument Tuning: Excellent control instrument tuning is vital for improving generation efficiency when the generation units are dispatched at different loads. Big Rivers' instrument department, along with outside contractors (Asea Brown Boveri ("ABB") Distributed Control System ("DCS") tuners), have continued to optimize the operation controls of the generation units to minimize any upsets while generation output is cycling.

Coal Pulverizer Tuning: Good combustion is important in maintaining good boiler efficiency, and a properly tuned coal pulverizer (mill) is vital to good combustion. Big Rivers routinely checks coal fineness on the pulverizers and the amount of loss on ignition ("LOI") in the boiler ash. Mill inspections are performed every 3,000 hours of operation. Also, Big Rivers periodically hires contractors to test pulverizer performance and balance coal flow through pulverizer coal pipes.

Big Rivers' generation performance continues to be very good. Table 9.1 presents the five year averages (2009-2013) of key performance indicators of the Big Rivers generating units.

Table 9.1
Key Performance Indicators per IEEE Standards

Unit	*Net Generation (MWHrs)*	*Net Heat Rate (BTU/kWH)*	*Gross Capacity Factor (%)*	*Gross Capacity Output (%)*	*Equivalent Availability Factor (%)*	*Equivalent Forced Outage Rate (%)*
Coleman 1	*996,951*	*10,826*	*77.1*	*84.1*	*91.5*	*6.9*
Coleman 2	*944,073*	*11,279*	*76.6*	*82.1*	*93.5*	*3.4*
Coleman 3	*1,074,102*	*10,775*	*80.6*	*85.7*	*93.0*	*3.7*
Green 1	*1,692,953*	*11,060*	*85.2*	*91.5*	*93.9*	*2.8*
Green 2	*1,604,239*	*11,128*	*83.3*	*91.9*	*93.6*	*1.3*
Henderson 1	*1,065,220*	*10,816*	*80.7*	*91.8*	*87.5*	*7.3*
Henderson 2	*1,053,449*	*11,122*	*76.6*	*85.9*	*88.3*	*5.6*
Wilson 1	*3,173,600*	*10,799*	*86.8*	*95.2*	*90.4*	*4.0*
SYSTEM	*11,561,827*	*11,028*	*81.8*	*90.4*	*91.5*	*4.1*

Big Rivers continues to utilize the Generation Knowledge Service ("GKS") benchmarking service provided by Navigant Consulting to compare unit performance against its peers. Big Rivers units have compared favorably, and Coleman Station has won Navigant's Operation Excellence Award in the Small Plant Category for the last two years (five year period from 2007-2011, and five year period from 2008-2012). The awards are based on detailed analysis of cost, performance and safety data from Navigant's industry-leading GKS® database, which contains data for more than seventy percent of the U.S. electric utility generation coal fleet—representing more than 216,000 MWs of generation and more than 640 coal-fired units. The analysis of cost and performance includes a weighted comparison of non-fuel operation and maintenance costs and availability/reliability measures during the five year evaluation period. Award winners must also demonstrate safety performance in the top half of their respective comparison groups.

9.2 Resource Addition Options

A list of potential resource additions was developed for the Strategist modeling process. This list of resources defines the options that the model is able to choose in order to meet planning reserve criteria. The list of potential additions includes traditional supply-side options, renewable supply-side options, and EE programs that were selected in the EE screening process. The list includes options that are typically included in potential resource assessments and represent generic generating assets. Selection of a particular type of resource from this list would indicate the type of capacity, rather than a specific asset, that would best serve new resource needs.

Potential capacity additions that were analyzed for this IRP are generic in nature in the sense that as Big Rivers approaches a time of capacity need, costs and availability of technically- and economically feasible alternatives will be assessed in great detail to ensure the optimum technology is chosen to fill actual needs. [redacted].

The complete list of options, along with a brief description of each option, is shown below.

Nuclear - The nuclear option was based on two 1,117 MW Westinghouse AP1000 units which would be built at an existing nuclear site. For this type unit, energy to heat water to produce steam is provided by splitting the nucleus of uranium atoms. AP1000 units are two-loop pressurized water reactors. Heated pressurized water enters a heat exchanger where lower pressure water is converted into steam. The facility has one steam generator for each reactor. Nuclear units have relatively low operating costs combined with relatively high capital costs and are used to serve base load requirements, i.e. the units operate to serve load that is present around the clock.

Coal - Coal costs and operating parameters were based on a 1300 MW supercritical pulverized coal facility, built in a greenfield location, in a dual-unit configuration. At this type facility, coal is burned to produce superheated steam in a boiler. The steam is supplied to a steam turbine, which drives an electric generator. As with nuclear units, coal units typically serve base load requirements.

Gas-fired Combined Cycle - Combined cycle capacity was modeled using characteristics of an advanced natural gas fired combined cycle unit. This type facility consists of two combustion turbines and associated generators, with one heat recovery steam generator and one steam turbine and associated electric generator. Combined cycle units are typically used to serve intermediate and/or base load needs, depending on the relative differences between the cost of natural gas and coal.

Gas-fired Combustion Turbine - Modeling data for the combustion turbine facility was based on a single natural gas fired combustion turbine and electric generator capable of producing 210 MW.

Biomass - Biomass data was based on a facility utilizing from 370 to 500 tons per day of wood, depending on moisture content, for the production of 20 MW of power. The facility would consist of a gasification system that converts wood to synthetic gas, and cleaning system for the gas, and a combined cycle plant to produce electricity.

Landfill Gas - Landfill Gas is produced during the decomposition of municipal solid waste ("MSW") while it is disposed of in MSW landfills. When landfills reach a certain size and generate non-methane organic compounds (a small component of landfill gas), federal air pollution regulations require the installation of a landfill gas collection and control system. By collecting the landfill gas before it can be emitted to the air, this fuel (which contains approximately 50 percent methane) can be used to power a combustion turbine to produce electricity.

Wind - Data used to model potential wind resources was based on a facility consisting of 67 wind turbine generators, each with a capacity of 1.5 MW, for a total design capacity of 100 MW. Each wind turbine generator is supported by a steel tower; main mechanical components of the wind turbine are attached to the top of the tower. Power is generated by the wind turbines and converted using onboard transformers.

Photovoltaic - The photovoltaic facility used as the basis of modeling data for this analysis is capable of producing 150 MW using arrays of ground-mounted, single-axis tracking modules which convert solar radiation into direct current electricity. The direct current electricity can then be converted to alternating current

Operating characteristics and associated costs for potential additions of supply-side resources were taken from the EIA's 2013 Annual Energy Outlook and from SNL Financial[59], and in some cases developed using GDS personnel's knowledge of actual projects.

Table 9.2 shows key variables associated with the supply-side options.

Table 9.2
Operating Characteristics of Supply-Side Options

	Capacity (MW)	2013 Overnight Capital Cost ($/kW)	Construction Lead Time (Yrs)	Operating Life (Yrs)	2013 Fixed O&M Rate ($/kW-Yr)	2013 Variable O&M Rate ($/MWh)	Heat Rate (MMBtu/MWh)	Availability (%)	SO_2 Emissions (lbs/MWh)	NO_x Emissions (lbs/MWh)	CO_2 Emissions (lbs/MWh)
Nuclear	50	5,584.00	6	30	94.67	2.17	10.46	90%	-	-	-
Coal	50	2,969.00	4	30	31.64	4.54	8.74	93%	0.79	0.44	1,931.54
Combined Cycle	50	1,036.00	3	30	15.60	3.32	6.33	90%	-	0.44	974.82
Combustion Turbine	50	683.00	2	30	7.14	10.52	8.55	90%	-	0.86	1,188.45
Biomass	50	3,978.00	4	20	107.21	5.34	13.50	90%		0.10	2,632.50
Landfill Gas	5	2,000.00	3	20	398.66	8.88	18.00	90%		1.55	
Wind	50	2,238.00	3	25	40.14	-		30%			
Photovoltaic	5	3,617.00	2	25	12.12	-		25%			

[59] http://www.snl.com/

Table 9.3 shows characteristics associated with all existing units in place in the Big Rivers Base Case IRP. A table showing costs and parameters for each Big Rivers generating unit for each year of the 2014 through 2028 period is included as Appendix F.

Table 9.3
Operating Characteristics of Existing Big Rivers Resources

Plant	*Unit*	*Location (Kentucky County)*	*Status*	*Commercial Operation Date*	*Type of Facility*	*Net Dependable Capability*		*Fuel Type*		*Typcial Fuel Storage Capability*
						Summer	Winter	Primary	Secondary	
K.C. Coleman	*1*	*Hancock*	*Existing*	*November 1969*	*Steam Turbine*	*146*	*146*	*Coal*	*Natural Gas*	*30 days*
K.C. Coleman	*2*	*Hancock*	*Existing*	*September 1970*	*Steam Turbine*	*146*	*146*	*Coal*	*Natural Gas*	*30 days*
K.C. Coleman	*3*	*Hancock*	*Existing*	*January 1972*	*Steam Turbine*	*151*	*151*	*Coal*	*Natural Gas*	*30 days*
R.D. Green	*1*	*Webster*	*Existing*	*December 1979*	*Steam Turbine*	*231*	*231*	*Coal*	*Oil*	*60 days*
R.D. Green	*2*	*Webster*	*Existing*	*January 1981*	*Steam Turbine*	*223*	*223*	*Coal*	*Oil*	*60 days*
Henderson 2	*1*	*Henderson*	*Existing*	*June 1973*	*Steam Turbine*	*153*	*153*	*Coal*	*Oil*	*60 days*
Henderson 2	*2*	*Henderson*	*Existing*	*April 1974*	*Steam Turbine*	*159*	*159*	*Coal*	*Oil*	*60 days*
R.A. Reid	*1*	*Henderson*	*Existing*	*January 1966*	*Steam Turbine*	*45*	*45*	*Coal*	*Oil*	*60 days*
R.A. Reid CT		*Henderson*	*Existing*	*March 1978*	*Combustion Turbine*	*65*	*65*	*Gas*		
D.B. Wilson	*1*	*Ohio*	*Existing*	*November 1986*	*Steam Turbine*	*417*	*417*	*Coal*	*Oil*	*60 days*

Table 9.4 presents fuel cost projections associated with the potential expansion units.

Table 9.4
Fuel Cost Projections
(Nominal $/MMBtu)

	Gas	*Biomass*	*Landfill*	*Nuclear*
2014	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]

9.3 Big Rivers' SEPA Allocation

Big Rivers' Base Case IRP plan includes capacity and energy from its Members' SEPA allocations as well as HMP&L's SEPA allocation, since HMP&L's SEPA allocation offsets the HMP&L load assumed in the plan. As a biological survey requirement during safety repairs to dams impounding Cumberland Lake, the U. S. Army Corps of Engineers (the "Corps") discovered the duskytail darter, listed as endangered under the Endangered Species Act, was associated with the dam safety project at Wolf Creek Dam. Completion of the Biological Opinion was the final piece of information required to decide about the Lake Cumberland pool level. In March, 2014, the U. S. Fish and Wildlife Service finalized a Biological Opinion that clears the way for the Corps to resume normal operations at Lake Cumberland. The dam safety remedial measures had previously been reviewed by Corps dam safety professionals, who recommended returning the lake to normal operations for 2014. The Corps' decision to allow Lake Cumberland to rise to a target elevation of 723 feet this summer, which is the normal elevation, is required prior to lifting of force majeure conditions. At this time, SEPA has indicated the possibility of partial scheduling of SEPA power beginning in July 2014. In preparing this IRP, Big Rivers assumes the return of full scheduling capabilities beginning in 2015.

In response to Big Rivers' inability to schedule SEPA power, MISO has disallowed SEPA as a qualifying capacity resource until the ability to schedule is reinstated. Total SEPA values are shown in Table 9.5. No other renewable resources, cogeneration or self-generation resources, or nonutility sources are indicated in the Base Case plan.

Table 9.5
SEPA Allocations

	SEPA Capacity (MW)	*SEPA Energy (GWh)*
2014	*0*	*342*
2015	*190*	*285*
2016	*190*	*285*
2017	*190*	*285*
2018	*190*	*285*
2019	*190*	*285*
2020	*190*	*285*
2021	*190*	*285*
2022	*190*	*285*
2023	*190*	*285*
2024	*190*	*285*
2025	*190*	*285*
2026	*190*	*285*
2027	*190*	*285*
2028	*190*	*285*

9.4 Purchased Power

In the preparation of this IRP, interaction with an economy energy market was modeled. The economy energy market was defined using projected prices for MISO. The price projections used were from Wood-Mackenzie. The monthly average prices that were used in the analysis are included with this filing as Appendix G. Capacity purchases from the market were not explicitly modeled in the production of the IRP. When new capacity is required, potential sources of that capacity could include self-build or unit participation by Big Rivers, or purchases of capacity from appropriate resources owned by others.

Table 9.6 presents energy input and generation by fuel type for each year of the IRP, as projected by the Strategist model.

Table 9.6
Energy Generation by Fuel Type

	Coal			*Gas*		
	(MWh)	*(000 MBtu)*	*(000 Tons)*	*(MWh)*	*(000 MBtu)*	*(000 MCF)*
2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

9.5 Overview of Existing and New DSM Programs Included in the Plan

Targeted classes and end-uses - Based on the results of the DSM Potential Study (Appendix B of this IRP), Big Rivers has elected to evaluate the following residential and C&I DSM programs in conjunction with the 2014 IRP. Table 9.7 lists the programs and the end-uses for each program.

Table 9.7
Energy Efficiency Programs and End Uses

Programs	*End Uses*
Residential Lighting Program	*Residential Lighting*
Residential Efficient Appliances Program	*Residential Appliances*
Residential HVAC Program	*Residential Heating and Cooling*
Residential Weatherization Program	*Residential Heating, Cooling, Water Heating and Lighting*
Residential New Construction Program	*Residential Heating and Cooling*
Residential HVAC Tune-Up Program	*Residential Heating and Cooling*
C&I Lighting Program	*Commercial and Industrial Lighting*
C&I HVAC Program	*Commercial and Industrial Heating, Cooling and Ventilation*
C&I General Program	*Commercial and Industrial – Various End Uses*

These nine programs are discussed in Section 5.1[60]. These programs address most of the major end-uses for the residential, commercial and industrial sectors.

Expected duration of the program - The Big Rivers Energy Efficiency Programs are based on the results of a 10-year DSM potential study. The results were projected through the 15-year IRP forecast under the assumption that similar programs with the same savings would be an investment that Big Rivers will continue to make. The programs presented in this IRP are based upon an annual expenditure of approximately $1 million in incentives in the first year. It is important to note that the estimated savings and costs of these programs in future years are not bound by a $1 million incentive cap, but instead represent what could be achieved if an initial investment of $1 million in incentives in 2014 is increased over time.

It is also important to note that current energy efficiency technologies may become standard practice in the future and that there will be new advancements in energy efficiency. As a result, Big Rivers and its Members will monitor the effectiveness of the recommended programs to determine if programmatic changes are warranted based on program performance. For example, CFLs may continue to achieve high levels of market penetration over the next several years, but the continued emergence of LED lighting may warrant periodic revisions to the residential lighting program offering.

Projected Energy and Peak Demand Changes by Season - The total energy savings in the first year of program implementation (2014) are projected to be 5,022 MWh with cumulative energy savings reaching 15,823 MWh in 2016, and total winter peak demand savings for all programs is projected to be 0.75 MW in the first year with cumulative savings reaching 2.33 MW in 2016. Likewise, summer peak demand savings for all programs is 0.86 MW in the first year, with cumulative savings reaching 2.65 MW in 2016. Table 5-13 in Section 5.1 provides a 3-year summary of the programs. Additional program savings documentation is provided in the DSM Potential Study in Appendix B of this IRP.

Projected Cost - The total Big Rivers investment for the mentioned DSM programs under evaluation is estimated to be $1 million in incentives in 2014. The estimated annual incentive costs increase to $1.27

[60] In the 2014 DSM Potential Study, the 12 programs currently offered were rolled into 9 programs.

million by 2023 as a result of inflation. The allocation of incentive dollars across sectors assumes that approximately two-thirds of the funding will go to residential sector programs and the remaining one-third will go to commercial and industrial sector programs.[61] This allocation aligns with current DSM spending.

Administrative costs include program design, program implementation, reporting and tracking, marketing, incentive fulfillment, and labor costs. In general, administrative costs were assumed to equal 20% of the incremental cost of measures. The estimated administrative budget is approximately $370,000 in 2014, and it increases to approximately $500,000 in 2023. The administrative budget estimates are based on typical levels of administrative costs relative to incentive spending observed in jurisdictions throughout the U.S. The actual administrative costs Big Rivers will incur will be based on the necessary effort to implement and evaluate the programs. Section 5.1 provides a table with the estimated incentive costs for each of the next 10 years. The DSM Potential Study report in Appendix B provides a table with the estimated administrative costs over the next 10 years. The program-level estimates of incentive and administrative costs are provided in several tables in Section 5.1.

The net present value of the estimated costs is also provided in Table 5.2 within Section 5.1. The net present value of the costs includes participant costs because the cost-effectiveness test used to evaluate DSM programs and measures is the Total Resource Cost test, which factors in utility costs as well as participant costs.

Projected Cost Savings – Table 9.8 provides the program-level estimates of cost savings. The cost savings equal the net benefits, or benefits minus costs. The costs are the sum of the utility and participant costs. The benefits[62] are primarily the electric savings, but also include non-electric benefits such as gas and water savings. Total cost savings are summarized in Table 5.2 in Section 5.1 of this IRP.

Table 9.8

Energy Efficiency Program Net Present Value Benefits

10-year	*NPV Benefits*	*NPV Costs*	*B/C Ratio*	*Net Benefits (Cost Savings)*
Residential Lighting Program	*$4,724,857*	*$1,765,652*	*2.68*	*$2,959,205*
Residential Efficient Appliances Program	*$9,363,432*	*$2,901,384*	*3.23*	*$6,462,048*
Residential HVAC Program	*$9,445,738*	*$3,045,654*	*3.10*	*$6,400,084*
Residential Weatherization Program	*$5,447,379*	*$2,560,435*	*2.13*	*$2,886,944*
Residential New Construction Program	*$5,244,956*	*$2,949,590*	*1.78*	*$2,295,366*
Residential HVAC Tune-Up Program	*$3,832,610*	*$3,678,942*	*1.04*	*$153,668*
C&I Lighting Program	*$11,449,531*	*$5,311,884*	*2.16*	*$6,137,648*
C&I HVAC Program	*$4,392,042*	*$1,466,519*	*2.99*	*$2,925,523*
C&I General Program	*$3,070,415*	*$1,752,324*	*1.75*	*$1,318,091*

[61] Industrial customers not including the 20 largest customers who have opted out of DSM program participation.

[62] The benefits include the utility's avoided generation, transmission and distribution costs, as well as other avoided cost benefits such as avoided gas and water benefits.

10. Electric Integration Analysis

10.1 Scenarios with Sensitivities

The Strategist Integrated Planning System, utilizing the 2013 Load Forecast was used to produce the 2014 IRP. The 2013 Load Forecast is fully described in Section 4 and Appendix A. All supply-side options, both traditional and renewable, were considered in a consistent manner by Strategist [redacted]. All of the options were modeled in a similar fashion with key data items consisting of capital costs, unit capability, unit availability, unit operating parameters such as heat rates, and unit operating costs. Unit addition decisions were made by the Strategist system to maintain planning reserve criteria and minimize the costs associated with expansion plans.

A sensitivity analysis approach was used in the development of this IRP to quantify Big Rivers' reliability and cost risks in different operating environments. The list of sensitivity cases is included in this document and, in summary, includes cases based on changes in load and energy expectations due to weather, economics, environmental regulations, and timing of replacement sales. The sensitivity cases also include changes, both upward and downward, in fuel prices, market prices, and costs associated with environmental considerations on the base case. As shown elsewhere, [redacted].

New renewable capacity resources were "forced" into Big Rivers' portfolio in the Renewable Portfolio Standard case. The renewable resources were not required to maintain adequate reserves in that case, but were installed in order to meet hypothetical renewable energy generation thresholds at particular points in time.

10.2 Base Case and Sensitivities

To address a multitude of uncertainties, the production simulation and expansion planning analysis was conducted for a Base Case and seventeen sensitivity cases. The Base Case was developed using (1) the base load and energy forecast, (2) the DSM programs included in the $1 million annual energy efficiency expenditure case, (3) base fuel price projections, (4) base expectations of resource operating parameters and costs, and (5) base market price projections as a source of economy energy purchases and as a potential market for economy energy sales.

The seventeen sensitivity cases examine the impacts of a number of uncertainties. Each case is listed below, and the major modeling input assumptions are identified for each case.

1. High Coal Price Case – to show the impact of high coal prices on Big Rivers' capacity and reserve requirements
    - Base Case assumptions for all variables except for:
    - 20% increase in coal prices

2. Low Coal Price Case – to show the impact of lower coal prices on Big Rivers' capacity and reserve requirements
    - Base Case assumptions for all variables except for:
    - 20% decrease in coal prices
3. High Market Energy Price Case – to show the impact of increased energy market prices on Big Rivers' capacity and reserve requirements
    - Base Case assumptions for all variables except for:
    - 20% increase in market energy prices
4. Low Market Energy Price Case – to show the impact of depressed energy market prices on Big Rivers' capacity and reserve requirements
    - Base Case assumptions for all variables except for:
    - 20% decrease in market energy prices
5. Extreme Weather Case – to reflect the impact of extreme weather conditions on Big Rivers' capacity, demand, and reserve requirements. Projected energy sales in the extreme case reflect higher annual heating degree days and cooling degree days than the base case. Projected peak demand in the extreme case reflects base case energy and extreme (low) load factor.
    - Base Case assumptions for all variables except for:
    - Extreme heating and cooling degree days and low system load factor
6. Mild Weather Case – to reflect the impact of mild weather conditions on Big Rivers' capacity, demand, and reserve requirements. Projected energy sales in the mild case reflect lower annual heating degree days and cooling degree days than the base case. Projected peak demand in the mild case reflects base case energy and extreme (high) load factor.
    - Base Case assumptions for all variables except for:
    - Mild heating and cooling degree days and high system load factor
7. Early Replacement Sales Case – to show the impact on Big Rivers' capacity, demand, and reserve requirements if Replacement Sales are accelerated to begin two years sooner than in the base case
    - Base Case assumptions for all variables except for:
    - Early Replacement Sales load and energy requirements forecast
8. Late Replacement Sales Case – to show the impact on Big Rivers' capacity, demand, and reserve requirements if Replacement Sales are delayed by two years from the base case
    - Base Case assumptions for all variables except for:
    - Late Replacement Sales load and energy requirements forecast

9. High Economics Case – to show the impact of an increase in the number of households and average income on Big Rivers' capacity, demand, and reserve requirements
   - Base Case assumptions for all variables except for:
   - High Economics load and energy requirements forecast
10. Low Economics Case – to show the impact of decreased number of households and lower average income on Big Rivers' capacity, demand, and reserve requirements
    - Base Case assumptions for all variables except for:
    - Low Economics load and energy requirements forecast
11. Environmental Case 1 – to show the impact on Big Rivers' capacity, demand, and reserve requirements of equipment additions to comply with certain proposed EPA regulations for Coal Combustion Residuals, Steam Effluent Guidelines, Section 316(b) of the Clean Water Act, and Mercury and Air Toxics Standards by 2019
    - Base Case assumptions for all variables except for:
    - Environmental Case 1 load and energy requirements forecast
    - Increase in variable O&M rates associated with environmental controls at the Coleman, Green, and HMP&L units
12. Environmental Case 2 – to show the impact on Big Rivers' capacity, demand, and reserve requirements of equipment additions to comply with proposed Cross State Air Pollution Rule, in addition to the regulations included in Environmental Case 1 by 2019
    - Base Case assumptions for all variables except for:
    - Environmental Case 2 load and energy requirements forecast
    - Increase in variable O&M rates associated with environmental controls at the Coleman, Green, Wilson, and HMP&L units
    - Lower SO_2 emission rates at Wilson and Green 1
13. High CO_2 Cost Case – to show the impact on Big Rivers' capacity, demand, and reserve requirements of compliance with potential carbon regulations via a carbon tax
    - Base Case assumptions for all variables except for:
    - $30/ton CO_2 cost beginning in 2020, escalating at 5%/year thereafter
    - Increase in market energy prices equivalent to 50% of carbon tax assumed
14. Low CO_2 Cost Case – to show the impact on Big Rivers' capacity, demand, and reserve requirements of compliance with potential carbon regulations via a carbon tax
    - Base Case assumptions for all variables except for:
    - $10/ton CO_2 cost beginning in 2020, escalating at 5%/year thereafter

- Increase in market energy prices equivalent to 50% of carbon tax assumed

15. High Market Capacity Price Case – to show the impact of high market capacity prices on Big Rivers' capacity and reserve requirements
    - Base Case assumptions for all variables except for:
    - 20% increase in market capacity prices
16. Low Market Capacity Price Case – to show the impact of low market capacity prices on Big Rivers' capacity and reserve requirements
    - Base Case assumptions for all variables except for:
    - 20% decrease in market capacity prices
17. Renewable Portfolio Standard Case– to show the impact on Big Rivers' capacity and reserve requirements of compliance with a hypothetical renewable portfolio standard
    - Base Case assumptions for all variables except for:

      RPS requirements of:
        - 15% of total Big Rivers energy provided by renewable resources by 2018
        - 20% of total Big Rivers energy provided by renewable resources by 2023
        - 25% of total Big Rivers energy provided by renewable resources by 2028

      Specific resources as sources of energy as follows:
        - 80% of RPS energy generated by wind projects
        - 15% of RPS energy generated by biomass projects
        - 5% of RPS energy generated by photovoltaic projects

Table 10.1 presents Big Rivers' Base Case capacity, demand and reserve information, for both winter and summer, for each year of the IRP.

Table 10.1
Base Case Resource Assessment Results
Capacity Requirements

Winter

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
									(2+3)		((1+6) x 10)	((1+6+11)	(9-(1+6))	(13/(1+6))
	Peak Load (MW)	*Existing Capacity (MW)*	*Planned Additions (MW)*	*Purchases from Other Utilities (MW)*	*Purchases from Non-Utilities (MW)*	*Energy Efficiency Demand Reductions (MW)*	*Wholesale Commitments (MW)*	*Planned Retirements (MW)*	*Total Capacity (MW)*	*Reserve Requirements Target (%)*	*Reserve Requirements Target (MW)*	*Total (MW)*	*Reserve Margin (MW)*	*Reserve Margin (%)*
2014														
2015														
2016														
2017														
2018														
2019														
2020														
2021														
2022														
2023														
2024														
2025														
2026														
2027														
2028														

[REDACTED]

Summer

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
									(2+3)		((1+6) x 10)	((1+6+11)	(9-(1+6))	(13/(1+6))
	Peak Load (MW)	*Existing Capacity (MW)*	*Planned Additions (MW)*	*Purchases from Other Utilities (MW)*	*Purchases from Nonutilities (MW)*	*Energy Efficiency Demand Reductions (MW)*	*Wholesale Commitments (MW)*	*Planned Retirements (MW)*	*Total Capacity (MW)*	*Reserve Requirements Target (%)*	*Reserve Requirements Target (MW)*	*Total (MW)*	*Reserve Margin (MW)*	*Reserve Margin (%)*
2014														
2015														
2016														
2017														
2018														
2019														
2020														
2021														
2022														
2023														
2024														
2025														
2026														
2027														
2028														

[REDACTED]

Table 10.2 presents Big Rivers' Base Case energy requirements and sources for each year of the IRP.

Table 10.2
Base Case Resource Assessment Results
Energy Requirements (GWH)

	Total Energy Requirements	*Economy Energy Sold*	*Energy Saved by EE Programs*	*Coal*	*Gas*	*Hydro (SEPA)*	*Economy Energy Purchased*	*Total Requirement Minus Economy Energy*	*Total Supply Minus Sales*
2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 10.3 shows [redacted], along with the 2013 present value of costs associated with each plan. The present value of costs includes (1) costs associated with EE programs, (2) fuel costs and variable O&M costs for all generating resources, both existing and new, (3) fixed O&M costs for all new generating resources, (4) annual carrying costs associated with capital costs for all new generating resources, (5) costs associated with economy energy purchases, and (6) deductions for revenue received for market energy sales. The present value of costs was calculated using a discount rate of 7.25%.

Table 10.3

[redacted]

	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]
PV Costs ($000)	[redacted]	[redacted]	[redacted]	[redacted]

Strategist output for the Big Rivers Base Case and each sensitivity case is included with this filing as Appendix H.

A map of Big Rivers' existing and planned transmission facilities is included as Appendix E. [redacted]

[redacted]

Based on the current projections of natural gas costs, the combined cycle unit was the generation choice for these sensitivities; however, recent events (extreme winter weather conditions and experiences) have caused significant questions to surface in the industry about natural gas costs and availability. If natural gas costs increase significantly, it is possible gas will lose much of the favor it currently enjoys in the electric power industry. If Big Rivers develops a need for generation in the future, a comprehensive analysis of combined cycle technology will be performed along with other technologies available at that point in time.

10.3 Reserve Margin Study

At Big Rivers' request, GDS conducted a reserve margin analysis in conjunction with the preparation of this IRP. The analysis was produced using the Ventyx Promod IV simulation tool. Big Rivers' participation in the MISO market was simulated using Promod's interconnection modeling capabilities. Because Big Rivers currently has available capacity, varying levels of reserve margins on its system were analyzed by simulating capacity sales by Big Rivers into the MISO market with capacity sales revenues estimated using a projection of MISO capacity prices. Total costs, which were compared for each level of reserve, included production costs associated with Big Rivers' resources and energy purchases from the MISO market. Revenues associated with capacity and energy sales into the MISO market were deducted from total costs.

Because capacity sales in the MISO market are independent from energy sales, for each level of reserve that was analyzed the total generation from Big Rivers' resources was assumed to be available to Big Rivers for its own use or for sales to the market. The result of this analysis demonstrated that Big Rivers' costs decreased as the level of required reserves decreased. Additionally, the analysis showed that, due to its participation in the MISO market, Big Rivers' system reliability was not compromised at decreasing reserve levels. Based on these results and because of Big Rivers' participation in the MISO market, the MISO PRM criteria were used for the development of this IRP.

The reserve margin criteria utilized for the analysis for the combined Big Rivers and HMP&L model are the Planning Reserve Margins for the 2014 through 2023 period which are shown in the 2014 MISO Loss of Load Expectation Study. These values range from 14.8% in 2014 to 17.3% in 2023. For the IRP study period years 2024 through 2028, the 2023 value of 17.3% was maintained. The Big Rivers Base Case and all other IRP Cases which include the Base Case load and energy requirements forecast [redacted].

11. Financial Information

Average system rates by year are shown as Member revenues per MWH sales in Table 11.1. The table is a general estimate that makes several broad assumptions in estimating Member revenues through 2028.

Several assumptions were made in estimating Member revenues:

- Base rates are assumed to be equal to the rates requested in the Big Rivers' rebuttal testimony for Case No. 2013-00199 presented before the Kentucky Public Service Commission.[63]

- The energy rate is assumed to remain constant throughout the period. Rate reductions (increases) are assumed in the demand charge of Member rates. Demand charges are adjusted to maintain a 1.40 TIER in 2019 and beyond.

- No incremental allowance costs for environmental compliance are assumed (assumed allocated and banked allowances cover emissions).

- Capital and variable costs for Mercury and Air Toxics Standards compliance was included in the environmental surcharge calculation and is reflected in the numbers in the following table (not including Coleman).

- Member Rate Stability Mechanism ("MRSM") funds are not included in this analysis as the actual calculated rates are unchanged by MRSM availability.[64]

- Replacement Load (Non-Member) is included per the Mitigation Plan - 100 MW added in each of the years 2016-2019 and 200 MW added in 2020 and 2021 for a total of 800 MW in 2021.

- The discount rate for NPV calculation is 7.25%, which is the same rate used for borrowing for environmental compliance in the sensitivities to the base case.

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[63] *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Case No. 2013-00199. Rebuttal Testimony of John Wolfram filed on June 24, 2013. Big Rivers received the Commission's order on April 25, 2014. The impacts of that order are not reflected in the 2014 IRP.

[64] The MRSM fund was established pursuant to a Commission order, dated October 9, 2009, in *In the Matter of: The Applications of Big Rivers Electric Corporation for: (I) Approval of Wholesale Tariff Additions for Big Rivers Electric Corporation, (II) Approval of Transactions, (III) Approval to Issue Evidences of Indebtedness, and (IV) Approval of Amendments to Contracts; and of E.ON U.S., LLC, Western Kentucky Energy Corp., and LG&E Energy Marketing, Inc., for Approval of Transactions*, Case No. 2007-00455.

Table 11.1
Revenue and Rate Projections

Year	*Nominal Member Revenue ($000)*	*2014 NPV Member Revenues ($000)*[1]	*Member Sales*[2] *(MWh)*	*Member Revenues/Sales ($/MWh)*	*Inflation*[3] *(%)*	*Cumulative Inflation Impact*	*Real Member Revenues ($000)*
2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1 *Based on discount rate of 7.25%*

2 *Represents energy sales to members including projected DSM impacts from new programs*

3 *Based on GDP Index, Moody's Analytics*

12. Action Plan

This IRP presents the basis for the actions Big Rivers will undertake in meeting future load requirements through a portfolio of supply-side and demand-side resources. Supporting documents, calculations, and tables are provided in the body of the report and appendices to this IRP.

[redacted]. The proposed actions over the next 3 years are in line with continued efforts to implement the Mitigation Plan filed in Big Rivers' 2012 Environmental Compliance Plan case, Case No. 2012-0063, as well as a continued focus on DSM programs. Big Rivers is well positioned with the flexibility to leverage market opportunities while pursuing replacement load opportunities. Whether market prices perform as forecasted, or fluctuate as included in the sensitivity analysis, Big Rivers will preserve the ability to benefit its Members and their retail customers with our existing fleet of resources.

12.1 Generation Portfolio

Big Rivers will continue to monitor EPA regulations, review testing processes and results, and evaluate compliance options for our existing generation portfolio. Big Rivers also will continue to emphasize generation efficiency by monitoring key performance indicators and utilizing benchmarking against peers to maintain productivity levels. Big Rivers' generating units are valuable assets with significant remaining useful lives that will be leveraged for the benefit of Big Rivers' Members for years to come.

12.2 Demand-Side Management

Big Rivers and its Member cooperatives will continue to manage the approved DSM budgets and evaluate existing and potential new programs for cost effectiveness and market acceptance. The inter-company DSM/Energy Efficiency working group will monitor efficiency and technology advancements for new end use options that may shift cost effectiveness of programs and provide additional DSM opportunities. Big Rivers will continue to monitor the market and will reevaluate the cost-effectiveness of demand response as market prices increase.

12.3 Mitigation Plan

Big Rivers has access to the wholesale power markets to buy and sell power, and the Big Rivers Mitigation Plan calls for Big Rivers to market excess power when the market price is greater than the marginal generation cost. The Base Case forecast includes a significant amount of replacement load to mitigate the loss of 850 MW load due to smelter contract terminations. With market prices depressed for the last several years, replacement sales are expected to begin in 2016 and increase with a rise in market prices to a level that replaces 800MW of load. During the interim period, when the wholesale power market does not support the production cost of generation, the plan is to idle up to two generating plants to eliminate the variable cost of production and reduce fixed departmental expense, labor, and labor overhead costs to Big Rivers' Members. With current market price projections, Big Rivers currently anticipates it may be cost effective to return idled plants in 2016 or 2017, depending on the market and the ability to secure sales; however, Coleman Station is not actually needed until 2019 to support replacement sales. As of the preparation date of this IRP, a forward sale has delayed the idling of the 417 MW Wilson Station through at least the end of February 2015. Per the Mitigation Plan, Big Rivers is continuing to evaluate options to execute forward bilateral sales agreements, enter into wholesale power contracts, and participate in capacity markets to find load replacement and to arrive at the most cost-effective alternative possible for Big Rivers' Members. Big Rivers is also supporting its Members as they actively pursue economic development opportunities in their service territories. In addition, Big Rivers will evaluate sales opportunities involving Coleman and Wilson plant to optimize member value.

Big Rivers will continue to optimize its generation and transmission assets to bring value to its Members. Big Rivers is well positioned to capitalize on the opportunity it has to develop a diversified portfolio of load that will utilize its existing assets and provide rate mitigation to its Members in the future.

Appendix A
2013 Load Forecast

[REDACTED]

BIG RIVERS ELECTRIC CORPORATION

2014 INTEGRATED RESOURCE PLAN

APPENDIX A
2013 LOAD FORECAST

CONFIDENTIAL

Information Submitted under Petition for Confidential Treatment

Appendix B

2014 DSM Potential Study

BIG RIVERS ELECTRIC CORPORATION

2014 INTEGRATED RESOURCE PLAN

APPENDIX B
DEMAND SIDE MANAGEMENT POTENTIAL STUDY

APPENDIX B
DEMAND SIDE MANAGEMENT POTENTIAL STUDY

GDS Associates, Inc.
Engineers and Consultants

BIG RIVERS ELECTRIC DEMAND-SIDE MANAGEMENT ("DSM") POTENTIAL STUDY

FINAL REPORT

Prepared for:

BIG RIVERS ELECTRIC CORPORATION

MAY 8, 2014

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1 EXECUTIVE SUMMARY

1.1 BACKGROUND

In October 2013, Big Rivers Electric Corporation ("Big Rivers" or "the Company") commissioned GDS Associates ("GDS") to conduct a study of the potential for electric energy efficiency and demand response programs to reduce electric consumption and peak demand throughout Big Rivers Members' service territories. Improving energy efficiency and lowering electric demand in homes, businesses, and industries can be a cost effective way to address the challenges of increasing energy costs and the increasing demand for energy. Consequently, demand-side management ("DSM") potential studies are important and helpful tools for identifying those DSM measures that are the most cost effective and that have the most significant electricity savings potential. The results of this study provide a roadmap for the development of detailed program plans for cost effective DSM measures.

This detailed report presents results from the evaluation of opportunities for energy efficiency programs in the Big Rivers Members' service territories[1]. Estimates of technical potential, economic potential, and achievable potential are provided for the ten year period spanning 2014-2023 for the residential and commercial/industrial ("C&I"), or non-residential) sectors. Results from two program potential scenarios are also presented to estimate the portion of the achievable potential that could be achieved given specific funding levels for existing Big Rivers DSM programs.

All results were developed using customized residential and C&I sector-level potential assessment computer models and Company-specific cost effectiveness criteria including the most recent Big Rivers avoided cost projections for electricity. The results of this study provide detailed information on energy efficiency measures that are cost effective and have potential kWh and kW savings. The data referenced in this report were the best available at the time this analysis was developed. As building and appliance codes and energy efficiency standards change, and as energy prices fluctuate, additional opportunities for energy efficiency may occur while current practices may become outdated. Actual energy and demand savings will depend upon the level and degree of voluntary member system participation in "DSM" programs.

1.2 STUDY SCOPE

This study examines the potential to reduce electric consumption and peak demand through the implementation of DSM technologies and practices in residential, commercial, and industrial facilities. The study assessed energy efficiency potential and demand response throughout Big Rivers Members' service territories over ten years, from 2014 through 2023.

The study had five primary objectives:

- Develop measure databases of energy efficiency and demand response measures in the residential and non-residential sectors. The measure database reflects current industry knowledge of energy efficiency and demand response measures, accounts for known codes and standards, and aligns with the market and demographics of Big Rivers Members' customers.

- Evaluate the electric DSM technical potential savings in Big Rivers Members' territories;

- Calculate the Total Resource Cost ("TRC") test and Utility Cost Test ("UCT") benefit-cost ratios for potential electric energy efficiency measures; determine the electric energy efficiency economic potential savings (using the TRC test) for Big Rivers Members;

[1] The report focuses on the energy efficiency component of DSM, but also includes an analysis of demand response potential. Chapters 6 and 7 provide the residential and non-residential energy efficiency potential results. Chapter 8 provides the demand response analysis.

- Evaluate the potential for achievable savings through DSM programs over a ten-year horizon (2014-2023);
- Estimate the potential savings over a ten-year period from the delivery of a portfolio of energy efficiency programs based on a specific funding level. The portfolio of energy efficiency programs has been designed based on a total incentive budget of $1 million in 2014 and increases to $1.27 million in 2023. The incentive budget of $1 million in 2014 aligns with current Big Rivers incentive budgets. At the direction of Big Rivers staff GDS also produces estimates of potential savings at an incentive budget of $2 million in 2014 (increasing to $2.54 million in 2023).

The scope of this study distinguishes among four types of energy efficiency potential; (1) technical, (2) economic, (3) achievable, and (4) program potential. The definitions used in this study for energy efficiency potential estimates are as follows:

- **Technical Potential** is defined in this study as the complete and immediate penetration of all measures analyzed where they were deemed to be technically feasible from an engineering perspective, without regard to economics.
- **Economic Potential** is the subset of technical potential resources that are cost-effective based on the Total Resource Cost test. Economic Potential is a theoretical estimate which disregards barriers to the implementation of energy efficiency.
- **Achievable Potential** is the realistic penetration of cost effective DSM measures taking into account real-world market and adoption barriers. Achievable Potential is the subset of Economic Potential which could be achieved if steps to address market barriers are taken in order to increase participation in energy efficiency programs. Incentives, marketing, and educational programs are examples of steps typically taken to address these barriers.
- **Program Potential** is the achievable potential possible given specific funding levels and program designs.

The definitions used in this study for technical, economic, and achievable potential energy efficiency potential estimates were obtained directly from a 2007 National Action Plan for Energy Efficiency (NAPEE) report[2]. Figure 1-1 below provides a graphical representation of the relationship of the various definitions of energy efficiency potential.

[2] http://www.epa.gov/cleanenergy/documents/suca/potential_guide.pdf.

Figure 1-1: Types of Energy Efficiency Potential[3]

Not Technically Feasable	Technical Potential			
Not Technically Feasable	Not Cost Effective	Economic Potential		
Not Technically Feasable	Not Cost Effective	Market & Adoption Barriers	Achievable Potential	
Not Technically Feasable	Not Cost Effective	Market & Adoption Barriers	Program Design, Budget, Staffing, & Time Constraints	Program Potential

Limitations to the scope of study: As with any assessment of DSM potential, this study necessarily builds on a large number of assumptions, including the following:

- Measure lives, measure savings and measure costs
- The discount rate for determining the net present value of future savings
- Projected penetration rates for energy efficiency measures
- Projections of electric generation avoided costs for capacity and energy
- Transmission and distribution avoided costs
- Future changes to energy efficiency codes and standards for buildings and equipment

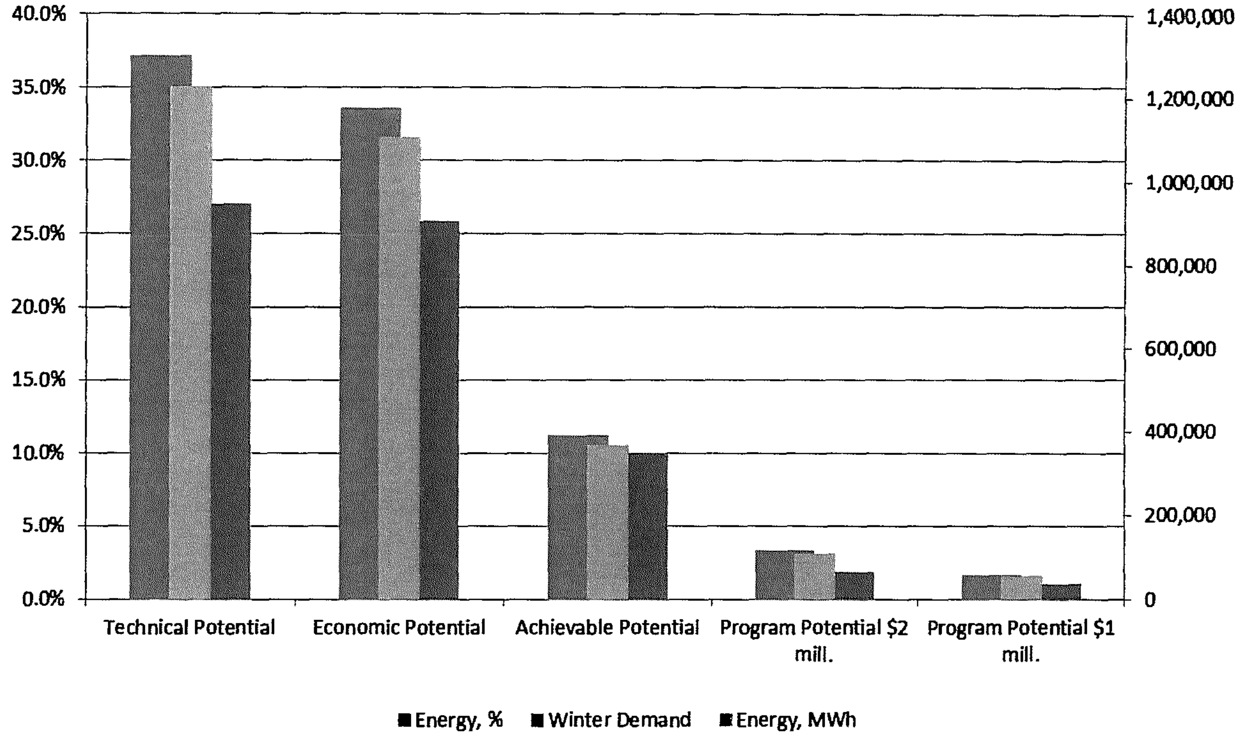
While the study seeks to use the best available data, there are many assumptions where there may be reasonable alternative assumptions that would yield somewhat different results. GDS exercised its professional judgment in choosing among alternatives in developing measures assumptions applicable to the residential and non-residential sectors in the Big Rivers Members' service territories.

1.3 Summary of Results

Figure 1-2 below shows that cost effective electric energy efficiency resources can play a significant role in the Big Rivers energy resource mix over the decade.

[3] Reproduced from "Guide to Resource Planning with Energy Efficiency" November 2007. US EPA. Figure 2-1, http://www.epa.gov/cleanenergy/documents/suca/resource_planning.pdf.

Figure 1-2: Electric Efficiency Potential Savings Summary[4]



This study examined nearly 400 energy efficiency measure permutations in the residential, commercial and industrial sectors combined. The study yielded an estimate of energy savings of 11.2% (368,891 MWh) and winter peak demand savings of 10.0% (65 MW) in the Achievable Potential scenario by the year 2023. The estimated Program Potential savings are 1.6% of sales (53,686 MWh) and winter peak savings of 1.1% (7 MW) in the $1 million incentive scenario, and 3.3% of sales (109,776 MWh) and winter peak savings of 1.8% (12 MW) in the $2 million incentive scenario. Table 1-1 below summarizes the results of the energy efficiency potential study Chapters 6 and 7 of this report provide the respective detail of the energy efficiency potential for the residential and non-residential sectors.

Table 1-1: Summary Results of Energy Efficiency Potential Study[5]

	Energy		Demand			
	MWh	% of 2023 MWh Sales	Winter MW	% of 2023 Winter Peak	Summer MW	% of 2023 Summer Peak
All Sectors Combined						
State-wide						
Technical Potential	1,227,010	37.2%	177	27.1%	256	37.8%
Economic Potential	1,106,964	33.6%	169	25.9%	192	28.3%
Achievable Potential	368,891	11.2%	65	10.0%	64	9.5%
Program Potential $2 mill.	109,776	3.3%	12	1.8%	18	2.7%
Program Potential $1 mill.	53,686	1.6%	7	1.1%	8	1.2%

4 The secondary axis on the right side of the chart shows the MWh savings of each scenario (aligns with green bars).
5 Chapters 6 and 7 have sector-level details of the results of the energy efficiency potential study. Chapter 8 provides the results of the demand response potential study. Collectively, the energy efficiency and demand response potential studies are referred to as the DSM potential study.

1.4 COST EFFECTIVENESS FINDINGS

This study concludes that significant cost effective electric potential remains available in the Big Rivers Member's territories. Table 1-2 shows the net present value benefits, costs and benefit-cost ratios for the Achievable Potential scenario and the two Program Potential scenarios examined in this study.

Table 1-2: TRC Benefit-Cost Ratios for Achievable Potential Scenarios For 2014 to 2023 Time Period

SCENARIOS	NPV $ BENEFITS	NPV $ COSTS	BENEFIT/COST RATIO	NET BENEFITS
Achievable Potential	$506,791,256	$236,486,056	2.14	$270,305,200
Program ($ 2 million)	$114,112,784	$50,901,486	2.24	$63,211,298
Program ($ 1 million)	$56,970,960	$25,432,384	2.24	$31,538,576

GDS used the TRC test to evaluate benefit/cost ratios for each individual energy efficiency measure considered in this study. Only measures that had a benefit/cost ratio greater than or equal to 1.0 were retained in the economic and achievable potential savings estimates. The benefits and costs in Table 1-2 account for all benefits and costs resulting from the implementation of the cost-effective measures included in the Achievable Potential and Program Potential scenarios.

1.5 REPORT ORGANIZATION

This report is organized by the following sections:

Section 1: Executive Summary: Provides an overall summary of the study.

Section 2: Glossary of Terms: Defines key terminology used in the report.

Section 3: Introduction: Highlights the purpose of this study and the importance of energy efficiency.

Section 4: Characterization of Big Rivers Members' Territories: Provides an overview of the Big Rivers Member's Territories including the geography, customer classes and a discussion of the forecasted electric energy sales by sector as well as forecasted electric peak demand.

Section 5: Potential Study Methodology: Details the approach used to develop the estimates of technical, economic and achievable potential savings for electric energy efficiency savings.

Section 6: Residential Electric Energy Efficiency Potential Estimates (2014-2023): Provides a breakdown of the technical, economic, achievable, and program potential energy efficiency savings potential in the residential sector.

Section 7: Non-Residential Electric Energy Efficiency Potential Estimates (2014-2023): Provides a breakdown of the technical, economic, achievable, and program potential energy efficiency savings potential in the non-residential sector.

Section 8: Demand Response Potential: Provides a summary of the demand response potential in the Big Rivers Member territory.

Section 9: Energy Efficiency Programs and Program Potential Summary: Describes the energy efficiency programs in the Program Potential scenarios at two different incentive funding levels.

Section 10: Overall Conclusions and Recommendations: Provides a summary of the DSM potential study in the Big Rivers Member territory and includes recommendations that can help Big Rivers achieve the estimated savings in the program potential scenarios.

2 GLOSSARY OF TERMS[6]

The following list defines many of the key energy efficiency terms used throughout this demand-side management potential study.

ACHIEVABLE POTENTIAL: The November 2007 National Action Plan for Energy Efficiency "Guide for Conducting Energy Efficiency Potential Studies" defines achievable potential as the amount of energy use that energy efficiency can realistically be expected to displace assuming the most aggressive program scenario possible (*e.g.*, providing end-users with payments for the entire incremental cost of more efficient equipment). This is often referred to as maximum achievable potential. Achievable potential takes into account real-world barriers to convincing end-users to adopt efficiency measures, the non-measure costs of delivering programs (for administration, marketing, tracking systems, monitoring and evaluation, etc.), and the capability of programs and administrators to ramp up program activity over time.

APPLICABILITY FACTOR: The fraction of the applicable housing units or businesses that is technically feasible for conversion to the efficient technology from an engineering perspective (e.g., it may not be possible to install compact fluorescent lamps ("CFLs") in all light sockets in a home because the CFLs may not fit in every socket in a home).

AVOIDED COSTS: Avoided costs are defined as the generation, transmission and distribution costs that can be avoided if the consumption of electricity can be reduced with energy efficiency or demand response programs.

BASE CASE EQUIPMENT END-USE INTENSITY: The electricity used per customer per year by each base-case technology in each market segment. This is the consumption of the electric energy using equipment that the efficient technology replaces or affects. For example, if the efficient measure is a high efficiency light bulb (CFL), the base end-use intensity would be the annual kWh use per bulb per household associated with an incandescent or halogen light bulb that provides equivalent lumens to the CFL.

BASE CASE FACTOR: The fraction of the market that is applicable for the efficient technology in a given market segment. For example, for the residential electric clothes washer measure, this would be the fraction of all residential customers that have an electric clothes washer in their household.

COST-EFFECTIVENESS: A measure of the relevant economic effects resulting from the implementation of an energy efficiency measure or program. If the benefits are greater than the costs, the measure is said to be cost-effective.

CUMULATIVE ANNUAL: Refers to the overall annual savings occurring in a given year from both new participants and annual savings continuing to result from past participation with energy efficiency measures that are still in place. Cumulative annual does not always equal the sum of all prior year incremental values as some energy efficiency measures have relatively short lives and, as a result, their savings drop off over time.

COMMERCIAL SECTOR: Comprised of non-manufacturing premises typically used to sell a product or provide a service, where electricity is consumed primarily for lighting, space cooling and heating, office equipment, refrigeration and other end uses. Business types are included in Section 5 – Methodology.

[6] Potential definitions taken from National Action Plan for Energy Efficiency (2007). "Guide for Conducting Energy Efficiency Potential Studies." Prepared by Philip Mosenthal and Jeffrey Loiter, Optimal Energy, Inc., http://www.epa.gov/cleanenergy/documents/suca/potential_guide.pdf.

DEMAND-SIDE MANAGEMENT ("DSM"): Refers to direct or indirect actions taken by a utility to affect customer demand. This study uses "DSM" to refer to both energy efficiency and demand response activities.

DEMAND RESPONSE: Refers to electric demand resources involving dynamic hourly load response to market conditions, such as curtailment or load control programs.

ECONOMIC POTENTIAL: The November 2007 National Action Plan for Energy Efficiency "Guide for Conducting Energy Efficiency Potential Studies" refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources as economic potential. Both technical and economic potential are theoretical numbers that assume immediate implementation of efficiency measures, with no regard for the gradual "ramping up" process of real-life programs. In addition, they ignore market barriers to ensuring actual implementation of efficiency. Finally, they only consider the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration, evaluation) that would be necessary to capture them.

END-USE: A category of equipment or service that consumes energy (*e.g.*, lighting, refrigeration, heating, process heat, cooling).

ENERGY EFFICIENCY: Using less energy to provide the same or an improved level of service to the energy consumer in an economically efficient way. Sometimes "conservation" is used as a synonym, but that term is usually taken to mean using less of a resource even if this results in a lower service level (*e.g.*, setting a thermostat lower or reducing lighting levels).

INCENTIVE COSTS: A rebate or some form of payment used to encourage people to implement a given DSM technology.

INCREMENTAL: Savings or costs in a given year associated only with new installations of energy efficiency or demand response measures happening in that specific year.

INDUSTRIAL SECTOR: Comprised of manufacturing premises typically used for producing and processing goods, where electricity is consumed primarily for operating motors, process cooling and heating, and space heating, ventilation, and air conditioning ("HVAC"). Business types are included in Section 5 – Methodology.

MEASURE: Any action taken to increase energy efficiency, whether through changes in equipment, changes to a building shell, implementation of control strategies, or changes in consumer behavior. Examples are higher-efficiency central air conditioners, occupancy sensor control of lighting, and retro-commissioning. In some cases, bundles of technologies or practices may be modeled as single measures. For example, an ENERGY STAR® ™ home package may be treated as a single measure.

MW: A unit of electrical output, equal to one million watts or one thousand kilowatts. It is typically used to refer to the output of a power plant.

MWH: One thousand kilowatt-hours, or one million watt-hours. One MWh is equal to the use of 1,000,000 watts of power in one hour.

PARTICIPANT COST: The cost to the participant to participate in an energy efficiency program.

PORTFOLIO: Either a collection of similar programs addressing the same market, technology, or mechanisms; or the set of all programs conducted by one energy efficiency organization or utility.

PROGRAM: A mechanism for encouraging energy efficiency that may be funded by a variety of sources and pursued by a wide range of approaches (typically includes multiple energy efficiency measures).

PROGRAM POTENTIAL: The November 2007 National Action Plan for Energy Efficiency 'Guide for Conducting Energy Efficiency Potential Studies" refers to the efficiency potential possible given specific program funding levels and designs as program potential. Often, program potential studies are referred to as "achievable" in contrast to "maximum achievable." In effect, they estimate the achievable potential from a given set of programs and funding. Program potential studies can consider scenarios ranging from a single program to a full portfolio of programs. A typical potential study may report a range of results based on different program funding levels.

REMAINING FACTOR: The fraction of applicable units that have not yet been converted to the electric energy efficiency measure; that is, one minus the fraction of units that already have the energy efficiency measure installed.

REPLACE-ON-BURNOUT: An energy efficiency measure is not implemented until the existing technology it is replacing fails or burns out. An example would be an energy efficient water heater being purchased after the failure of the existing water heater at the end of its useful life.

RESOURCE ACQUISITION COSTS: The cost of energy savings associated with energy efficiency programs, generally expressed in costs per first year or per lifetime MWh saved ($/MWh), kWh ($/kWh).

RETROFIT: Refers to an efficiency measure or efficiency program that seeks to encourage the replacement of functional equipment before the end of its operating life with higher-efficiency units (also called "early retirement") or the installation of additional controls, equipment, or materials in existing facilities for purposes of reducing energy consumption (e.g., increased insulation, low flow devices, lighting occupancy controls, economizer ventilation systems).

SAVINGS FACTOR: The percentage reduction in electricity consumption resulting from application of the efficient technology. The savings factor is used in the formulas to calculate energy efficiency potential.

SOCIETAL COST TEST ("SCT"): Measures the net benefits of the energy efficiency program for a region or service area as a whole. Costs included in the SCT are costs to purchase and install the energy efficiency measure and overhead costs of running the energy efficiency program. The SCT may also include non-energy costs, such as reduced customer comfort levels. The benefits included are the avoided costs of energy and capacity, plus environmental and other non-energy benefits that are not currently valued by the market.

TECHNICAL POTENTIAL: The theoretical maximum amount of energy use that could be displaced by energy efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end-users to adopt the energy efficiency measures. It is often estimated as a "snapshot" in time assuming immediate implementation of all technologically feasible energy saving measures, with additional efficiency opportunities assumed as they arise from activities such as new construction.

TOTAL RESOURCE COST ("TRC") TEST: The TRC measures the net benefits of the energy efficiency program for a region or service area as a whole from the combined perspective of the utility and program participants. Costs included in the TRC are costs to purchase and install the energy efficiency measure and overhead costs of running the energy efficiency program. Costs include all costs for the utility and the participants. The benefits included are the avoided costs of energy and capacity plus any quantifiable non-energy benefits (such as reduced emissions of carbon dioxide).

USEFUL LIFE: The number of years (or hours) that the new energy efficient equipment is expected to function. Useful life is also commonly referred to as "measure life."

UTILITY COST TEST ("UCT"): The UCT measures the net benefits of the energy efficiency program for a region or service area as a whole from the utility's perspective. Costs included in the UCT are the utility's costs to design, implement and evaluate a program. The benefits included are the avoided costs of energy and capacity.

3 INTRODUCTION

This report assesses the potential for electric energy efficiency and demand response programs to assist Big Rivers in meeting future energy service needs. This section of the report provides the following information:

- Defines the term "energy efficiency";
- Describes the general benefits of energy efficiency programs;
- Provides results of similar energy efficiency potential studies conducted in other states; and,
- Describes contents of the Sections of this report.

The purpose of this DSM potential study is to provide a detailed assessment of the technical, economic and achievable potential for electric energy efficiency potential in the Big Rivers Members' territories. This study has examined a full array of energy efficiency technologies and energy efficient building practices that are technically achievable. The results of this study can be used to develop energy efficiency goals for Big Rivers. The strategies that will be developed based on this potential study will provide direction and scope of utility-administered energy efficiency programs in reducing electric and energy consumption in the Big Rivers Member territories.

3.1 INTRODUCTION TO ENERGY EFFICIENCY

Efficient energy use, often referred to as energy efficiency, is using less energy to provide the same level of energy service. An example would be insulating a home or business to use less heating and cooling energy to achieve the same inside temperature. Another example would be installing light emitting diode ("LED") lighting in place of incandescent lights to attain the same level of illumination. In general, energy efficiency is achieved primarily through more efficient technologies and/or processes rather than by changes in individual behavior.

3.1.1 Energy Efficiency Activity

Making homes and buildings more energy efficient is seen as a largely untapped resource for addressing energy security and fossil fuel depletion. Faced with increasing energy prices, constraints in energy supply and demand, and energy reliability concerns, states are turning to energy efficiency as the most reliable, cost-effective, and quickest resource to deploy. For example, the state of California began implementing energy-efficiency measures in the mid-1970s, including building codes and appliance standards with strict efficiency requirements. During the following years, California's energy consumption has remained approximately flat on a per capita basis while national U.S. consumption doubled[7]. As part of its strategy, California implemented a three-step plan for new energy resources that puts energy efficiency first, renewable electricity supplies second, and new fossil-fired power plants last.

In 2004, the American Council for an Energy Efficient Economy ("ACEEE") reviewed 11 studies on the technical, economic, and achievable potential for energy efficiency in the U.S. Overall, the findings suggest that substantial potential savings remain throughout the nation; the technical energy efficiency savings potential was estimated at 33% of total U.S. electric consumption. In early 2009, the Electric Power Research Institute (EPRI) estimated the maximum achievable potential for energy savings at 8% of total U.S. electric consumption[8].

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[7] Mufson, Steven. "In Energy Conservation, California Sees the Light." *Washington Post*. February 17, 2007. Page A01, http://www.washingtonpost.com/wp-dyn/content/article/2007/02/16/AR2007021602274.html?referrer=emailarticle.
[8] Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010-2030). Completed by the Electric Power Research Institute (EPRI). January 2009, http://www.epri.com/abstracts/pages/productabstract.aspx?ProductID=000000000001016987.

A more recent study by ACEEE offers information regarding the current savings and spending related to energy efficiency by state[9]. Based on self-reported data, the top energy efficient states spend more than 3% of statewide annual electric utility sales revenue on energy efficiency programs. The median level of spending across all states is nearly 1.1% of statewide electric utility sales revenues. In addition, the top states are currently achieving annual electric energy efficiency savings of 1-2% of total electric retail sales. The median level of annual electric energy efficiency savings across all states is nearly 0.6% of total electric retail sales. These findings suggest additional opportunities remain for energy efficiency in the Commonwealth of Kentucky and throughout the U.S.

3.1.2 General Benefits of Energy Efficiency

There are a number of benefits that accrue to Big Rivers and its Members due to electric energy efficiency programs. These benefits include avoided cost savings, non-electric benefits such as water and fossil fuel savings, environmental benefits, economic stimulus, job creation, risk reduction, and energy security.

Avoided electric energy and capacity costs are based upon the costs an electric utility would incur to construct and operate new electric power plants or to purchase power from another source. These avoided costs of electricity include both fixed and variable costs that can be directly avoided through a reduction in electricity usage. The energy component includes the costs associated with the production of electricity, while the capacity component includes costs associated with the capability to deliver electric energy during peak periods. Capacity costs consist primarily of the costs associated with building peaking generation facilities. The forecasts of electric energy and capacity avoided costs used in this study were provided to GDS by Big Rivers.

At the consumer level, energy efficient products often cost more than their standard efficiency counterparts, but this additional cost is balanced by lower energy consumption and lower energy bills. Over time, the money saved from energy efficient products will pay consumers back for their initial investment as well as save them money on their electric bills. Although some energy efficient technologies are complex and expensive, such as installing new high efficiency windows or a high efficiency air-source heat pump, many are simple and inexpensive. Examples of simple and inexpensive energy efficient measures include low-flow water devices and CFL bulbs, which can be installed by most homeowners without the need of home energy professionals.

Although the reduction in electric costs is the primary benefit to be gained from investments in energy efficiency, Big Rivers, their members, and society as a whole can also benefit in other ways. Many electric efficiency measures also deliver non-energy benefits. For example, low-flow water devices and efficient clothes washers also reduce water consumption. Similarly, weatherization measures such as ceiling insulation and duct sealing that fortify the building shell not only save on air conditioning costs in the summer, but also can save the customer money on space heating fuels, such as natural gas or propane[10]. Reducing electricity consumption also reduces harmful emissions from power plants, such as SO_X, NO_X, CO_2 and particulates into the environment.

Energy efficiency programs create both direct and indirect jobs. The manufacture and installation of energy efficiency products involves the manufacturing sector, research and development of efficient technologies, and the service industry to install complex energy efficient measures and implement energy efficiency programs. These are skilled positions that are not easily outsourced to other states and countries. The creation of indirect jobs is more difficult to quantify, but result from households and businesses experiencing increased discretionary income from reduced energy bills. These savings

[9] The 2013 State Energy Efficiency Scorecard. Report #E13K. ACEEE. November 2013, http://www.aceee.org/research-report/e13k.

[10] These non-electric benefits would accrue to Big Rivers customers who utilize non-electric heating as either a primary or secondary heating source during the heating season.

produce multiplier effects, such as increased investment in other goods and services driving job creation in other markets.

Energy efficiency reduces risks associated with fuel price volatility, unanticipated capital cost increases, environmental regulations, supply shortages, and energy security. Aggressive energy efficiency programs can help eliminate or postpone the risk associated with committing to large investments for generation facilities a decade or more before they are needed. Energy efficiency is also not subject to the same supply and transportation constraints that impact fossil fuels. Finally, energy efficiency reduces competition between states and utilities for fuels, and reduces dependence on fuels imported from other states or countries to support electricity production. Energy efficiency can help meet future demand increases and reduce dependence on out-of-state or overseas resources.

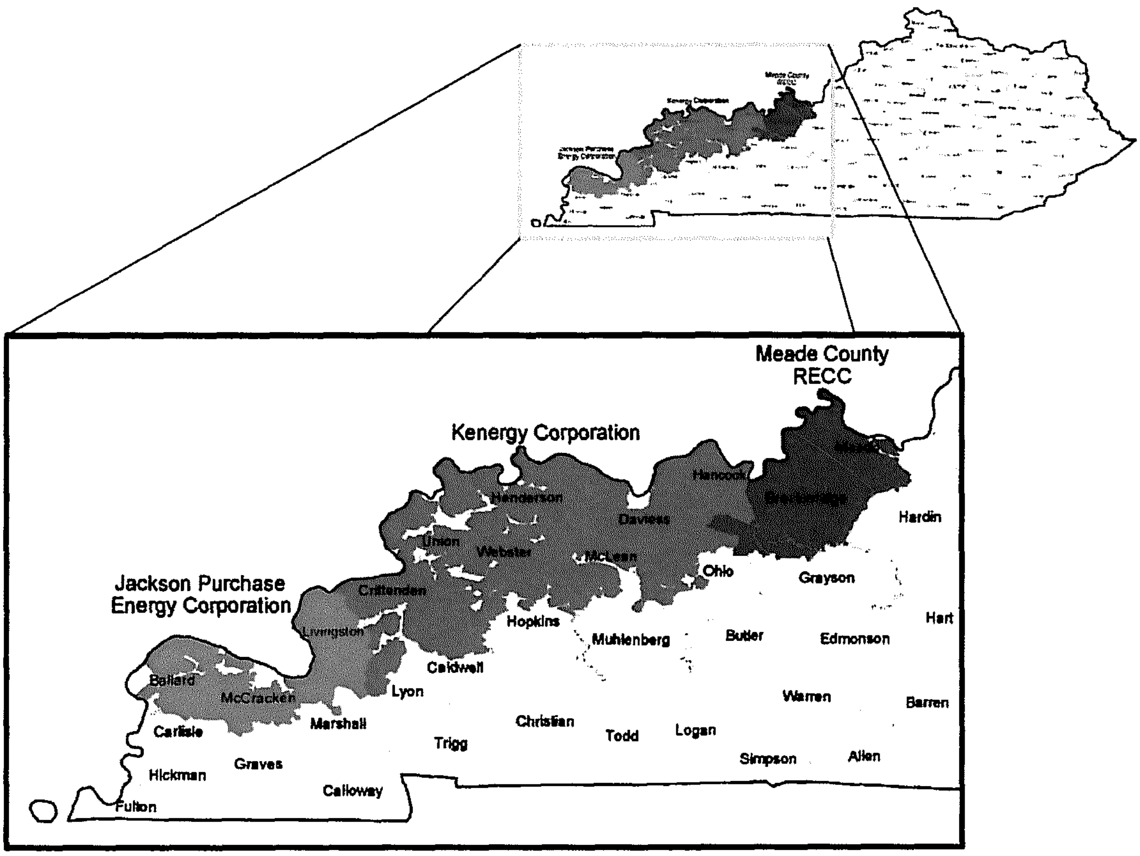
4 CHARACTERIZATION OF BIG RIVERS MEMBER'S SERVICE TERRITORIES

In order to develop estimates of electricity savings potential, it is important to understand the extent to which electricity is used by households and businesses in Big Rivers Members' territories. This section provides a brief overview of the Big Rivers Members' territories, the historical and forecasted electric energy sales and system peak demand, and the on-going energy efficiency efforts of the Big Rivers Member systems.

4.1 BIG RIVERS MEMBER'S SERVICE TERRITORIES

Big Rivers is a generation and transmission cooperative headquartered in Henderson, Kentucky which provides wholesale power to three Member distribution cooperatives: Kenergy Corp. ("Kenergy"), Jackson Purchase Energy Corporation ("JPEC"), and Meade County Rural Electric Cooperative Corporation ("MCRECC"), all of which provide retail electric service to consumers located in western Kentucky. Big Rivers provides full power requirements for each of its three Member cooperatives. Big Rivers' member cooperatives provide electric service in 22 counties located in western Kentucky. The climate in the area is humid, temperate and continental.

Figure 4-1: Big Rivers Electric Corporation Member's Service Territory



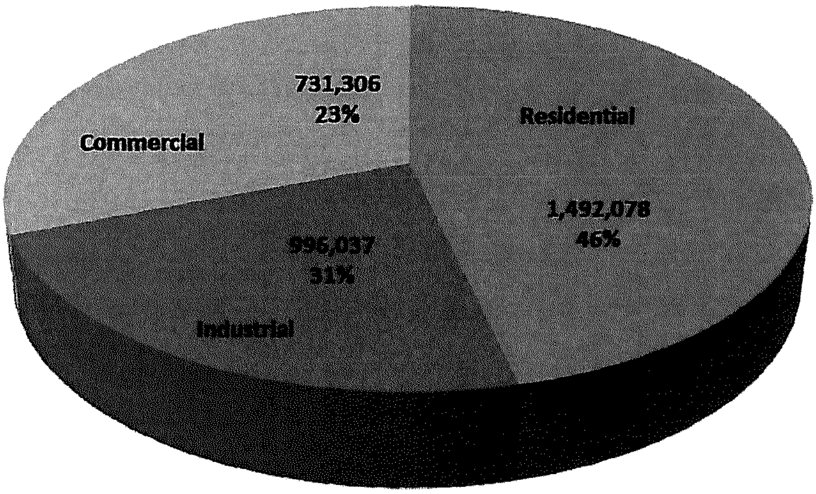
The total owned generation capacity is 1,444 MW which includes capacity from four stations. Big Rivers also has contractual rights to 197 MW from the Station Two plant owned by Henderson Municipal Power and Light, and 178 MW of hydro capacity from the Southeastern Power Administration

("SEPA"). This additional capacity brings the total net capacity availability to 1,819 MW. Big Rivers owns, operates and maintains a 1,285 mile transmission system and transmits power to its Members and third-party entities under the MISO Tariff.

4.2 CUSTOMER CLASS OVERVIEW

According to 2013 historical sales data, the residential sector accounts for 46% of total energy sales while the small and large C&I sectors account for 23% and 31%, respectively.

Figure 4-2: 2013 Historical Energy Sales by Customer Class (MWh)[11]



The residential sector consists of primarily single-family household customers. According to 2013 appliance surveys conducted by the Big Rivers Member Cooperatives, approximately 91% of households are single family homes, 8.5% are manufactured homes and 0.5% are considered multi-family homes. Survey respondents indicated that electric cooling systems are present in nearly all of the households. More than 50% of households report electric heating as the primary fuel source for space heating in the Big Rivers Members' territories. This estimate is up from 43% in 2010. Natural gas and propane are the primary heating sources (47%) for most of the homes that do not use electric heating as the primary heating source. Approximately 60% of all homes have electric water heating. This estimate is down from 68% in 2010.

This study relied on data from the EIA's Commercial Building and Energy Consumption Survey using the East South Central regional data to segment the data for the non-residential analysis. The East South Central region includes Kentucky, Tennessee, Mississippi and Alabama. Details on the data segmentation can be found in Section 7 of this study.

4.3 FORECAST OF CONSUMERS, ENERGY SALES & PEAK DEMAND (2014-2023)

Table 4-1 displays a reference case of forecasted data of the number of electric members. Table 4-2 presents annual MWh sales by sector. In these tables, MWh sales for the small commercial sector refer to small commercial/industrial loads at or less than 1,000 kW, while large commercial/industrial includes those customers whose peak demand exceeds 1,000 kW. These two categories were combined for the commercial/industrial sector analysis.

[11] This data excludes 2013 smelter sales.

Table 4-1: Forecast Number of Members (2014-2023)

TOTAL BIG RIVERS SYSTEM				
MEMBERS				
Year	Residential	Small Commercial	Large Commercial / Industrial	Total
2014	98,761	17,669	20	116,450
2015	99,723	17,820	20	117,563
2016	100,671	17,968	20	118,659
2017	101,591	18,111	20	119,721
2018	102,459	18,246	20	120,725
2019	103,313	18,370	20	121,703
2020	104,176	18,496	20	122,692
2021	105,041	18,620	20	123,680
2022	105,884	18,739	20	124,643
2023	106,711	18,856	20	125,587
Compound Annual Avg. Rate of Growth	*0.78%*	*0.65%*	*0.00%*	*0.76%*

The Big Rivers load forecast for the Member's territories projects that total MWh sales at the customer meter will grow by 114,420 MWh over the next decade, at a compound average annual growth rate of 0.36% per year. The residential and commercial sectors are projected to grow at 0.54% and 0.43% a year, respectively, while the industrial load forecast does not predict growth from the large commercial and industrial sector.

Table 4-2: Forecast Sales Data, MWh (2014-2023)

TOTAL BIG RIVERS SYSTEM				
MWh Sales				
Year	Residential	Small Commercial	Large Commercial / Industrial	Total
2014	1,476,266	724,071	981,796	3,182,133
2015	1,456,291	714,689	985,814	3,156,794
2016	1,449,745	711,463	985,325	3,146,533
2017	1,464,578	718,648	982,555	3,165,781
2018	1,478,045	725,205	982,555	3,185,806
2019	1,492,474	730,722	982,555	3,205,752
2020	1,507,739	736,617	982,555	3,226,912
2021	1,524,147	742,952	982,555	3,249,654
2022	1,541,192	749,564	982,555	3,273,311
2023	1,558,220	756,178	982,555	3,296,953
Compound Annual Avg. Rate of Growth	*0.54%*	*0.43%*	*0.01%*	*0.36%*

Electric system winter peak load[12] is projected to grow from approximately 609 MW in 2014 to 652 MW by the year 2023. During 2014 through 2023, system peak demand is estimated to increase by 30 MW in the residential sector, with an additional 13 MW increase attributed to the small commercial/industrial sector. The summer peak demand is also expected to grow from 637 MW to 678 MW across the 2014-2023 timeframe.

Table 4-3: Forecast Winter Peak Demand from 2014-2023

TOTAL BIG RIVERS SYSTEM

Winter Peak

Year	Residential	Small Commercial	Large Commercial / Industrial	Total
2014	378	119	112	609
2015	379	120	115	613
2016	381	120	115	617
2017	386	122	115	623
2018	389	123	115	626
2019	392	124	115	631
2020	396	125	115	636
2021	400	126	115	641
2022	404	128	115	646
2023	408	129	115	652
Compound Annual Avg. Rate of Growth	*0.77%*	*0.77%*	*0.24%*	*0.68%*

Table 4-4: Forecast Summer Peak Demand from 2014-2023

TOTAL BIG RIVERS SYSTEM

Summer Peak

Year	Residential	Small Commercial	Large Commercial / Industrial	Total
2014	389	123	126	637
2015	389	123	126	638
2016	392	124	125	641
2017	397	125	125	647
2018	400	126	125	651
2019	403	127	125	656
2020	407	129	125	661
2021	411	130	125	666
2022	416	131	125	672
2023	420	133	125	678
Compound Annual Avg. Rate of Growth	*0.78%*	*0.78%*	*-0.04%*	*0.62%*

[12] Peak demand includes distribution losses.

5 ENERGY EFFICIENCY POTENTIAL STUDY METHODOLOGY[13]

This section describes the overall methodology that was utilized to develop the energy efficiency potential study for Big Rivers. The main objective of this energy efficiency potential study is to quantify the electric energy efficiency savings potential in the Big Rivers Member's territories. This report provides estimates of the potential kWh and kW electric savings for each level (technical, economic, achievable and program potential) of energy efficiency potential. This document describes the general steps and methods that were used at each stage of the analytical process necessary to produce the various estimates of energy efficiency potential.

Energy efficiency potential studies involve a number of analytical steps to produce estimates of each type of energy efficiency potential. This study utilizes benefit/cost screening tools for the residential and non-residential sectors to assess the cost effectiveness of energy efficiency measures. These cost effectiveness screening tools are Excel-based models that integrate technology-specific impacts and costs, customer characteristics, utility avoided cost forecasts and other valuation modeling parameters such as discount and inflation rates. Excel was used as the modeling platform to provide transparency to the estimation process and allow for simple customization based on Big Rivers' unique characteristics and the availability of specific model input data. This section describes major analytical steps and provides an overview of how the potential savings are calculated. Specific differences in methodology from one sector to another are also discussed in this section.

5.1 MEASURE LIST DEVELOPMENT

Energy efficiency measure lists were based on the analysis team's existing knowledge and current databases of electric end-use technologies and energy efficiency measures, and were supplemented as necessary to include other technology areas of interest to Big Rivers' Members. The study scope was restricted to measures and practices that are currently commercially available. These are measures that are of most immediate interest to energy efficiency program planners.

In addition, this study focused on measures that could be relatively easily substituted for or applied to existing technologies on a retrofit or replace-on-burnout basis. Replace-on-burnout applies to equipment replacements that are made normally in the market when a piece of equipment is at the end of its useful life. A retrofit measure is eligible to be replaced at any time in the life of the equipment or building. Replace-on-burnout measures are generally characterized by incremental measure costs and savings (e.g. the costs and savings of a high-efficiency versus standard efficiency air-source heat pump); whereas retrofit measures are generally characterized by full costs and savings (e.g. the full costs and savings associated with retrofitting ceiling insulation into an existing attic.)

5.2 MEASURE CHARACTERIZATION

A significant amount of data is needed to estimate the savings potential for individual energy efficiency measures or programs across the entire existing residential, commercial and industrial sectors. To this extent, considerable effort was expended to identify, review, and document all available data sources. This review allowed development of reasonable assumptions regarding measure lives; installed incremental and full costs (where appropriate); and electric energy and demand savings for each measure included in the final lists of measures in this study.

13 The demand response portion of the DSM potential study methodology is discussed in Chapter 8.

Savings: Estimates of annual measure savings as a percentage of base equipment usage were developed from a variety of sources, including:

- Technical reference manuals (e.g. Indiana, Illinois, Mid-Atlantic, Pennsylvania, etc.)
- Building energy modeling software and engineering analyses
- Secondary sources such as American Council for an Energy-Efficient Economy ("ACEEE"), U.S. Department of Energy ("DOE"), Energy Information Administration ("EIA"), Energy Star® calculators
- Program evaluations conducted by other utilities and program administrators

Measure Costs: Measure costs represent either incremental or full cost, and typically include the cost of installation. Cost estimates were derived from:

- Technical reference manuals
- Secondary sources such as ACEEE, Energy Star®, Northeast Energy Efficiency Partnerships ("NEEP") publications
- Retail store pricing and industry experts
- Evaluation reports

Measure Life: Represents the number of years (or hours) that energy-using equipment is expected to operate. Useful life estimates were derived from:

- Technical reference manuals
- Manufacturer data
- Savings calculators and Life-cycle cost analyses
- Secondary sources such as ACEEE, Energy Star®
- The California Database for Energy Efficient Resources ("DEER") database
- Evaluation reports

Baseline and Efficient Technology Saturations: In order to assess the amount of energy efficiency savings still available, estimates of the current saturation of baseline equipment and energy efficiency measures are necessary. The residential sector relied mainly on 2013 appliance surveys conducted by the Big Rivers Member Cooperatives. The commercial sector utilized regional specific data available from the 2003 Commercial Buildings Energy Consumption Survey ("CBECS") conducted by the EIA.

Further detail regarding the development of measure assumptions for energy efficiency in the residential and commercial/industrial sectors can be found later in Sections 6 and 7 of this report. Appendices A, B and C include measure level detail for the residential, small commercial and large commercial / industrial sectors.

5.3 Role of Naturally Occurring Conservation

Naturally occurring conservation exists through government intervention, improved manufacturing efficiencies, building energy codes, market demand, and increased energy efficiency implementation by early adopters, who will implement measures without explicit monetary incentives. The impacts of new Federal government mandated energy efficiency standards have already been reflected in the baseline data for equipment unit energy consumption being used for this potential study. These new government standards, such as the new standards included in the Federal government's Energy Independence and Security Act ("EISA 2007")[14] can significantly increase naturally occurring potential through tax incentives, stimulus funding or stricter manufacturing standards. These forces cause certain sector end-

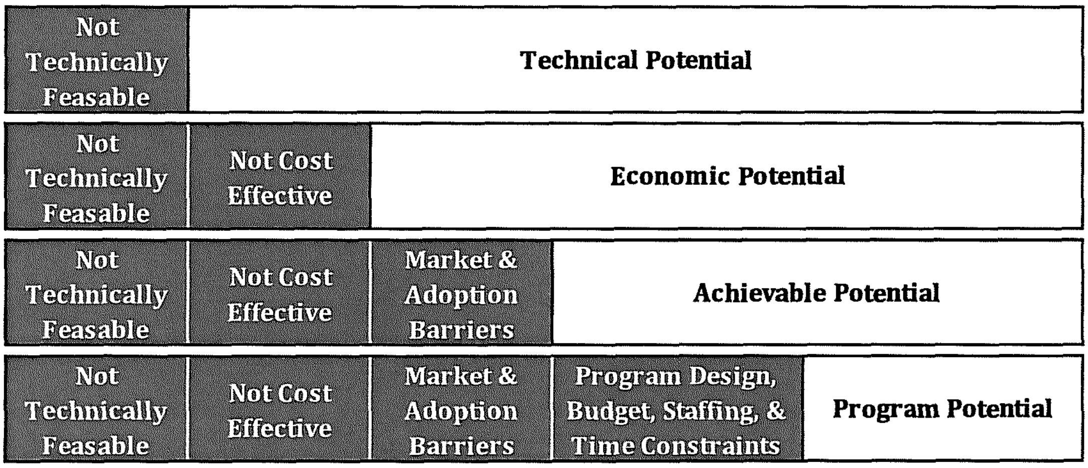
[14] PUBLIC LAW 110-140—DEC. 19, 2007. Energy Independence and Security Act of 2007, http://www.gpo.gov/fdsys/pkg/PLAW-110publ140/pdf/PLAW-110publ140.pdf

use energy consumption values to improve across the baseline forecast. It is important to account for these forces as thoroughly as possible to ensure the energy efficiency potential is not double-counted, by over-stating the potential that could occur for end-uses where codes and standards are reducing baseline unit energy consumption. This study reflects the impacts of the EISA 2007 including provisions of the Act which were phased in from 2012-2014 and a backstop provision that will be enacted in 2020. This study accounts for upcoming changes to federal standards for other appliances such as air-source heat pumps, refrigerators and freezers. These adjustments reduce energy efficiency potential starting in the years these standards come into effect, and in subsequent years.

5.4 Potential Savings Overview

Potential studies often distinguish between four different types of efficiency potential: technical, economic, achievable, and program. However, because there are often important definitional issues among studies, it is important to understand the definition and scope of each potential estimate as it applies to this analysis. Figure 5-1 below provides a graphical representation of the relationship of the various definitions of energy efficiency potential.

Figure 5-1: Types of Energy Efficiency Potential[15]



The first two types of energy efficiency potential - technical and economic potential - provide a theoretical upper bound for energy savings. The best designed portfolio of programs is unlikely to achieve 100% of the technical or economic potential due to myriad implementation barriers. Therefore, achievable and program potential tend to be more useful assessments because they estimate what is realistically achievable at certain incentive levels, when the potential can be captured, and how much it would cost program administrators to capture the potential.

5.5 Technical Potential

This study uses the energy efficiency potential definitions included on pages 2-4 of the November 2007 National Action Plan for Energy Efficiency (NAPEE) Guide for Conducting Energy Efficiency Potential Studies. Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end-users to adopt the efficiency measures. It is often estimated as a "snapshot" in time assuming immediate implementation of all technologically feasible energy saving measures, with additional efficiency opportunities assumed as they arise from activities such as new construction[16].

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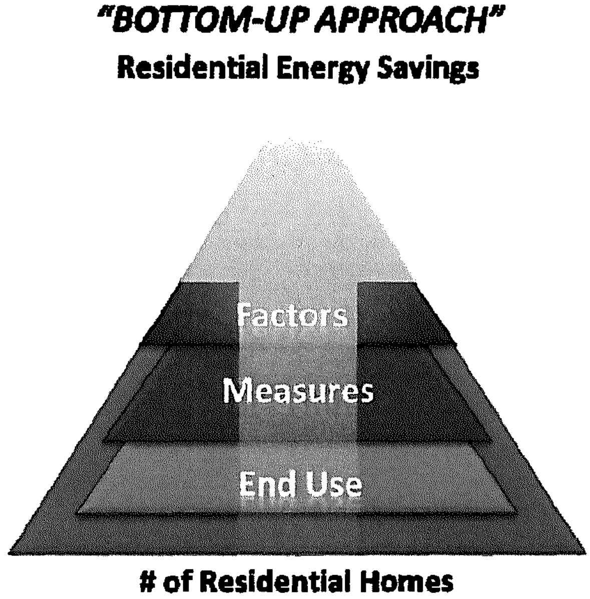
[15] Reproduced from "Guide to Resource Planning with Energy Efficiency November 2007" written by the US EPA. Figure 2-1, http://www.epa.gov/cleanenergy/documents/suca/resource_planning.pdf.

[16] National Action Plan for Energy Efficiency, "Guide for Conducting Energy Efficiency Potential Studies", page 2-4, http://www.epa.gov/cleanenergy/documents/suca/potential_guide.pdf.

This study utilizes a "bottom-up" approach in the residential sector to calculate the potential of an energy efficiency measure or set of measures as illustrated in Figure 5-2 below. A bottom-up approach was used for the residential sector due to the amount of data available for the residential sector. A bottom-up approach first starts with the savings and costs associated with replacing one piece of equipment with its high efficiency counterpart, and then multiplies these values by the number of measures available to be installed throughout the life of the program.

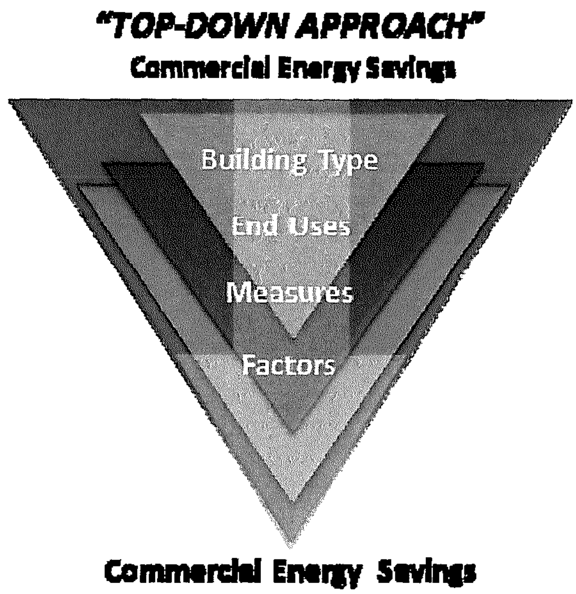
Figure 5-2: Residential Sector Savings Methodology - Bottom Up Approach



As shown in Figure 5-2, the methodology starts at the bottom based on the number of residential customers (splitting them into single-family, multi-family and manufactured housing types as well as existing homes vs. new construction). From that point, estimates of the size of the eligible market in the Big Rivers territory were developed for each energy efficiency measure. For example, energy efficiency measures that affect electric space heating are only applicable to those homes that have electric space heating.

The bottom-up approach is applicable in the residential sector because of better secondary data availability and greater homogeneity of the building and equipment stock to which measures are applied, compared to the non-residential sector. However, this methodology was not utilized in the non-residential sector. For the non-residential sector, a "top-down" approach was used for developing the technical potential estimates. The "top down" approach builds an energy use profile based on estimates of kWh sales by business segment and end use. Savings factors for energy efficiency measures are then applied to applicable end use energy estimates after assumptions are made regarding the fraction of sales that are associated with inefficient equipment and the technical/engineering feasibility of each energy efficiency measure. As shown in Figure 5-3, the top-down potential estimate begins with a disaggregated energy sales forecast, and then estimates what percentage of these sales a given efficiency measure will save.

Figure 5-3: Non-Residential Sector Savings Methodology – Top Down Approach

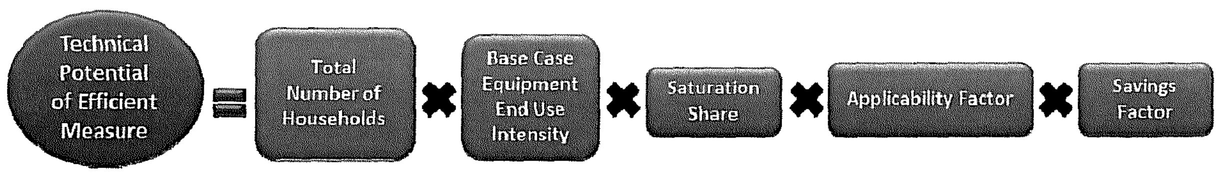


In developing the overall potential electricity savings, the analysis accounts for the interactive effects of measures designed to impact the same end-use. For instance, if a home were to properly seal all ductwork, the overall space heating and cooling consumption in that home would decrease. As a result, the remaining potential for energy savings derived from a heating/cooling equipment upgrade would be reduced. In instances where there are two (or more) competing technologies for the same electrical end use, such as heat pump water heaters, water heater efficiency measures and high-efficiency electric storage water heaters, in most cases an equal percentage of the available population is assigned to each measure using the applicability factor[17]. In the event that one of the competing measures is not found to be cost-effective, the homes/buildings assigned to that measure are transitioned over any of the remaining cost effective alternatives.

5.5.1 Core Equation for the Residential Sector

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown below in Equation 5-1 below.

Equation 5-1: Core Equation for Residential Sector Technical Potential



Where:

- **Total Number of Households** = the number of households in the market segment (e.g. the number of households living in detached single-family buildings)
- **Base Case Equipment End-use Intensity** = annual energy consumption (kWh) used per customer, per year, by each base-case technology in each market segment. This is the

[17] GDS used its professional judgment in some cases to assign unequal applicability factors to attempt to avoid overstating or understating the potential of the set of competing technologies.

consumption of energy using equipment that efficient technology replaces or affects. This variable fully accounts for any known building characteristics in the service area, such as average square footage of homes.

- **Saturation Share** = this variable has two parts: the first is the fraction of the end use energy that is applicable for the efficient technology in a given market segment. For example, for electric residential water heating, this would be the fraction of all residential electric customers that have electric water heating in their household; the second is the share of the end use energy that is applicable for the efficient technology that has not yet been converted to an efficient technology.
- **Applicability Factor** = this factor ensures that a household cannot receive two of the same type of measure. For example, if we assume there are two tiers of ceiling insulation, one which yields 10% savings and another which yields 20% savings, a household that needs more ceiling insulation may elect to either install the 10% savings measure or the 20% savings measure, but could not receive both units. In general, this study applies an even distribution to the same type of measure across eligible households when applying this factor. This study may, in some cases, assign weighted applicability factors, if it believes an even distribution is inappropriate[18]. The applicability factor also captures the fraction of applicable units technically feasible for conversion to the efficient technology from an engineering perspective (e.g., it may not be possible to add wall insulation in all homes because the original construction of some homes does not allow for wall insulation to be installed without requiring major reconstruction of the house, which would be an additional cost that does not yield any energy benefits).
- **Savings Factor** = the percentage of energy consumption reduction resulting from application of the efficient technology. The savings factor is a general term used to illustrate the calculation of a measure's technical potential. The Excel-based model GDS uses fully integrates the necessary assumptions to determine the measure-level savings, given the **Base Case Equipment End-use Intensity**, and the expected savings of each technology.

Technical energy efficiency potential in the residential sector is calculated in two steps. In the first step, all measures are treated **independently**; that is, the savings of each measure are not reduced or otherwise adjusted for overlap between competing or interacting measures. By analyzing measures independently, no assumptions are made about the combinations or order in which they might be installed in customer buildings. However, the cumulative technical potential cannot be estimated by adding the savings from the individual savings estimates because some savings would be double-counted. For example, the savings from a measure that reduces heat loss from a building, such as insulation, are partially dependent on other measures that affect the efficiency of the system being used to heat the building, such as a high-efficiency air-source heat pump; the more efficient the air-source heat pump, the less energy saved from the installation of the insulation. In the second step, adjustments are made to account for such interactive effects. The adjustments for interactive effects were made by upgrading the baseline conditions while holding the savings percentages constant. The upgraded baseline conditions vary by measure and assume some measures (such as weatherization measures) are installed to increase the building efficiency prior to the installation of the measure that is subject to the baseline adjustment (ex. efficient air-source heat pump).

5.5.2 Core Equation for the Commercial and Industrial Sector

The core equation utilized in the commercial sector technical potential analysis for each individual efficiency measure is shown below in Equation 5-2.

[18] For example, if historical data indicates a technology has been able to garner a large share of the market GDS may assign a higher applicability factor to this technology in order to properly reflect this knowledge.

Equation 5-2: Core Equation for Commercial Sector Technical Potential

$$\text{Technical Potential of Efficient Measure} = \text{Total End Use Sales by Industry Type} \times \text{Base Case Factor} \times \text{Remaining Factor} \times \text{Convertible Factor} \times \text{Savings Factor}$$

Where:

- **Total end-use kWh sales by commercial sector and by building type** = the forecasted electric sales level for a given end use (e.g., space heating) in a commercial or industrial industry type (e.g., office buildings or fabricated metals).
- **Base Case factor** = the fraction of end-use energy applicable for the efficient technology in a given commercial sector type. For example, with fluorescent lighting, this would be the fraction of all lighting kWh in a given industry type that is associated with fluorescent fixtures.
- **Remaining factor** = the fraction of applicable kWh sales associated with equipment not yet converted to the electric energy efficiency measure; that is, one minus the fraction of the industry type with energy efficiency measures already installed.
- **Convertible factor** = the fraction of the equipment or practice that is technically feasible for conversion to the efficient technology from an engineering perspective (e.g., it may not be possible to install variable-frequency drives (VFDs) on all motors.
- **Savings factor** = the fraction of electric consumption reduced by application of the efficient technology.

For the commercial sector, the development of the energy efficiency technical potential estimate begins with a disaggregated energy sales forecast over the ten year forecast horizon (2014 to 2023). The commercial sector energy sales forecast is broken down by building type, then by electric end use. Then a savings factor is applied to end use electricity sales to determine the potential electricity savings for each end use. The commercial sector, as defined in this analysis, is comprised of the following business segments:

- Education
- Warehouse
- Retail
- Grocery
- Office
- Lodging
- Healthcare
- Restaurant
- Institutional
- Service
- Other

Similar to the residential sector, technical electric energy efficiency savings potential in the commercial sector is calculated in two steps. In the first step, all measures are treated **independently**; that is, the savings of each measure are not reduced or otherwise adjusted for overlap between competing or synergistic measures. By treating measures independently, their relative economics are analyzed without making assumptions about the order or combinations in which they might be implemented in customer buildings. However, the total technical potential across measures cannot be estimated by summing the individual measure potentials directly because some savings would be double-counted. For example, the savings from a weatherization measure, such as low-e ENERGY STAR windows, are partially dependent on other measures that affect the efficiency of the system being used to cool or heat the building, such as high-efficiency space heating equipment or high-efficiency air conditioning systems; the more efficient the space heating equipment or electric air conditioner, the less energy saved from the installation of low-e ENERGY STAR windows. Accordingly, the second step is to rank the measures based on a metric of cost-effectiveness (using the Total Resource Cost test) and adjust savings for interactive effects so that total savings are calculated incrementally with respect to measures that precede them.

5.6 Determining Cost-Effectiveness

For the economic and achievable potential, it is necessary to develop a method by which it can be determined that a measure or program is cost effective. There are several tests for evaluating energy efficiency's cost-effectiveness, each reflecting a different stakeholder perspective on the impact of energy efficiency. The Total Resource Cost test, which measures the regional net benefits, is the most common test used to evaluate energy efficiency and is the appropriate test from a regulatory perspective. This study examines measure cost effectiveness based on the Total Resource Cost (TRC) test[19] at the direction of Big River's personnel. The study also used the TRC test for the 2010 Big Rivers energy efficiency and demand response potential study.

The TRC Test measures the net costs of an energy efficiency measure or program as a resource option based on the total costs of the program, including both the participant's and the utility's costs. The benefits include the avoided electric supply costs, the reduction in transmission, distribution, generation, and capacity costs (valued at marginal cost for the period when there is an electric load reduction), and savings of other resources such as fossil fuels and water. The costs are the program costs paid both by the utility and the participants. All equipment costs (including: installation, operation and maintenance, cost of removal, and administration costs) are included in this test. Results are typically expressed as either net benefits or a benefit-to-cost ratio.

Other tests that are used in evaluating energy efficiency throughout the U.S. are discussed briefly below, but were not used to determine cost effectiveness for this study.

The Utility Cost Test ("UCT"): also called the Program Administrator's Test, considers only the avoided energy costs as benefits and counts only expenditures incurred by the utility;

The Participant Cost Test ("PCT"): uses retail energy rates and incentives received to value the benefits of energy savings and count only costs paid directly by participants;

The Rate Impact Measure ("RIM) Test: uses the same benefits and costs as the utility test, but also counts the lost sales revenue as a cost;

The Societal Cost Test ("SCT"): uses the same costs as the TRC test, but includes societal benefits such as avoided participant costs for hypothesized change in medical expenses due to healthier surroundings.

The TRC Test estimates the total costs of obtaining efficiency savings without considering who pays these costs. This approach does not address distributional equity, such as how costs and benefits would be shared among or within groups. In this regard, the TRC Test differs from other benefit-cost perspectives such as the utility test, participant test, and RIM Test.

5.7 Economic Potential

Economic potential refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources. The study calculates the benefit/cost ratios for this study according to the cost effectiveness test definitions provided in the November 2008 National

[19] In addition, GDS provided Big Rivers the measure level cost-effectiveness screening results using the Utility Cost Test (UCT), the Rate Impact Measure (RIM) test, the Societal Cost Test (SCT), and the Participant Cost Test (PCT).

Action Plan for Energy Efficiency guide titled "Understanding Cost Effectiveness of Energy Efficiency Programs." Both technical and economic potential are theoretical numbers that assume immediate implementation of energy efficiency measures, with no regard for the gradual "ramping up" process of real-life programs. In addition, they ignore market barriers to ensuring actual implementation of energy efficiency. Finally, they typically only consider the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration, program evaluation, etc.) that would be necessary to capture them.

Furthermore, all measures that were not found to be cost-effective based on the results of the measure-level cost effectiveness screening were excluded from the economic and achievable potential. Then allocation factors were re-adjusted and applied to the remaining measures that were cost effective.

5.8 ACHIEVABLE POTENTIAL

Achievable potential is the amount of energy use that efficiency and demand response can realistically be expected to save assuming an aggressive market penetration and funding scenarios. Achievable potential takes into account barriers that hinder consumer adoption of energy efficiency measures such as financial, political and regulatory barriers, the administrative and marketing costs associated with efficiency programs, and the capability of programs and administrators to ramp up activity over time.

Achievable potential can also vary with energy efficiency program parameters, such as the magnitude of rebates or incentives offered to customers for installing energy efficiency measures. Thus, many different scenarios can be modeled. This study assumed a 35% incentive for most measures. This assumption was used for the 2010 Big Rivers DSM potential study and aligns with typical levels of incentives offered by program administrators throughout the U.S. GDS assumed a 100% incentive for weatherization measures in order to align with current DSM program practices in the Big Rivers Member's territories.

For new construction, energy efficiency measures can be implemented when each new home or building is constructed, thus the rate of availability is a direct function of the rate of new construction. For existing homes and buildings, determining the annual rate of available savings is more complex. Achievable savings potential in the existing stock of buildings can be captured over time through two principle processes:

1) As equipment replacements are made in the market when a piece of equipment is at the end of its useful life (referred to as replace-on-burnout);

2) At any time in the life of the equipment or building (referred to as the retrofit case).

For the replace-on-burnout measures, existing equipment is assumed to be replaced with high efficiency equipment at the time a consumer is shopping for a new appliance or other energy consuming equipment, or if the consumer is in the process of building or remodeling. Using this approach, only equipment that needs to be replaced in a given year is eligible to be upgraded to energy efficient equipment. For the retrofit measures, savings can theoretically be captured at any time. However, in practice, it takes many years to retrofit an entire stock of buildings, even with the most aggressive of energy efficiency programs.

In the process of estimating the achievable potential it is important to recognize changing standards to energy-consuming equipment. When equipment is scheduled for federal or state code upgrades, these improvements to equipment performance result in decreased savings potential for the year the code is to be enacted and for all subsequent years. Consequently, it is important that equipment code changes, particularly planned improvements to incandescent lighting, be reflected in all achievable potential models for all sectors.

5.9 PROGRAM POTENTIAL

Program potential refers to the potential energy efficiency savings that is possible given specific program funding levels and designs. The starting point for analyzing the savings and costs resulting from the implementation of the program scenario is the achievable potential. The following steps are used to estimate the program scenario potential:

- Defining eligible measures within each recommended program and projecting future measure penetrations
- Developing program incentive costs based on program incentive structure and designs and estimated participation rates for each measure
- Developing non-measure program budgets (costs for all programmatic activities except measure incentives)
- Analyzing the portfolio to develop estimates of overall costs, benefits, net benefits, and benefit cost ratios.

The programs presented in Section 9 of this report are based initial incentive funding levels of $1 million and $2 million in 2014. The spending for each scenario fluctuates from 2014-2023 based on the achievable potential calculated for the residential and non-residential sectors. It is important to note that the measures included in the program potential scenario are a subset of those included in the achievable potential. Measure penetrations are customized to reflect existing program design and offerings, and to align with current program budgets. As a result, program assumptions may vary slightly from the assumptions utilized for the achievable base case scenario.

6 RESIDENTIAL ELECTRIC ENERGY EFFICIENCY POTENTIAL ESTIMATES (2014 TO 2023)

Figure 6-1 and Table 6-1 presented below, summarize the technical, economic, and achievable savings potential for the Big Rivers service area by 2023.

The potential estimates are expressed as cumulative 10-year savings, as percentages of 2023 sector sales. The technical potential is 44.1% in 2023. The 10-year economic potential is 40.1% based on the TRC test screening, assuming an incentive level equal to 35% of the measure cost for most measures. The 10-year achievable potential savings is 14.4% of 2023 sector sales.

Energy efficiency measures and programs can also serve to lessen peak demand. The estimated peak demand savings in the achievable potential scenario are 12.7% of forecasted winter peak demand in 2023 and 9.0% of forecasted summer demand in 2023.

Figure 6-1: 2023 Summary of Cumulative Residential Energy Efficiency Potential

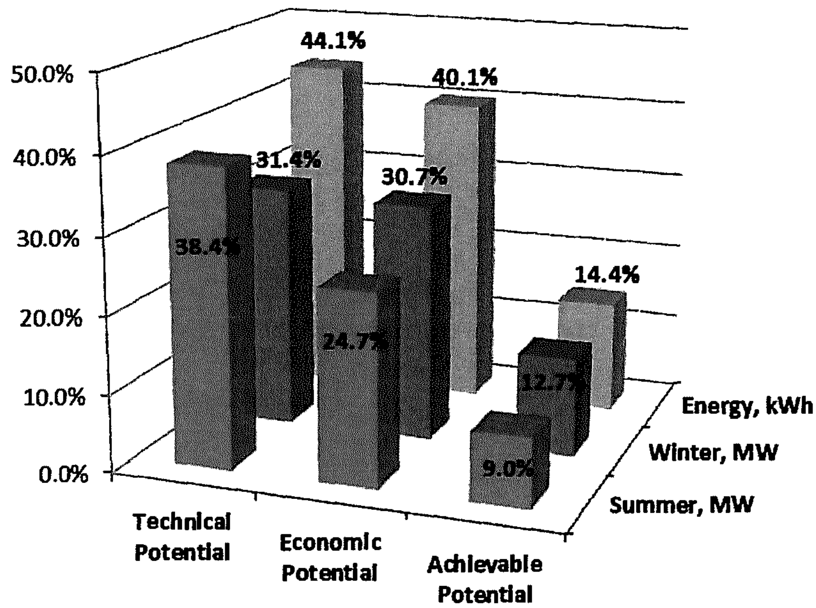


Table 6-1: 2023 Summary of Cumulative Residential Energy and Demand Savings Potential

	Energy		Demand			
	MWh	% of 2023 MWh Sales	Winter MW	% of 2023 Winter Peak	Summer MW	% of 2023 Summer Peak
BIG RIVERS TERRITORY						
Technical Potential	687,182	44.1%	128	31.4%	161	38.4%
Economic Potential	625,263	40.1%	125	30.7%	104	24.7%
Achievable Potential	224,381	14.4%	52	12.7%	38	9.0%

6.1 Residential Energy Efficiency Measures Examined

For the residential sector, there were 310 total electric savings measures included in the potential energy savings analysis[20]. Table 6-2 provides a brief description of the types of measures included for each end use in the residential model. The list of measures was developed based primarily on a review of the Indiana Technical Reference Manual (IN TRM) and measures found in other residential potential studies and other TRMs for states and regions near Kentucky. Measure data includes incremental costs, electricity energy and demand savings, gas and water savings, and measure life.

Table 6-2: Measures and Programs Included in the Electric Residential Sector Analysis

End Use Type	End Use Description	Measures Included
HVAC Envelope	Building Envelope Upgrades	• Air/duct Sealing • Improved Insulation (Ceiling and Floor) • Efficient Windows • Radiant Barrier • Weatherization Package (insulation, air/duct sealing, CFL bulbs, low flow devices)
HVAC Equipment	Heating/Cooling/Ventilation Equipment	• Existing HVAC Tune-Up • Efficient Air-Source Heat Pump • Dual Fuel Heat Pumps • Geothermal Heat Pumps • Ductless Mini-split Systems (Heat pumps and ACs) • Efficient Central AC Systems • Programmable/Smart Thermostats • Efficient Room Air Conditioners • Room Air Conditioner Recycling • Efficient Furnace Fans
Water Heating	Domestic Hot Water Heating	• Heat Pump Water Heater • Solar Water Heater • Low Flow Showerhead/Faucet Aerator • Pipe Wrap • Tank Wrap (Water Heater Blanket)
Lighting	Interior/Exterior Lighting	• Specialty CFLs • Standard CFLs • Standard LEDs • Specialty LEDs • Efficient Exterior Lighting (CFLs and LEDs) • Efficient Torchiere Lamps • LED Night Lights
Appliances	High-Efficiency Appliances / Retirement of Inefficient Appliances	• ENERGY STAR Clothes Washers • ENERGY STAR Refrigerator • ENERGY STAR Freezers • ENERGY STAR Dishwashers • ENERGY STAR Dehumidifiers • Heat Pump Dryers • Secondary Refrigerator/Freezer Recycling

[20] This total represents the number of unique electric energy efficiency measures and all permutations of these unique measures. For example, there are 17 permutations of the ceiling insulation measure to account for the various insulation levels, housing types, heating/cooling combinations, construction types.

END USE TYPE	END USE DESCRIPTION	MEASURES INCLUDED
Electronics	High Efficiency Consumer Electronics	• Controlled Power Strips • Efficient Set-Top Boxes • ENERGY STAR Desktops • Efficient Laptops • Efficient Televisions • Efficient Monitors
Behavioral	Consumer Response to Feedback from Utility	• Direct (Real-Time) Feedback • Indirect Feedback
Other	Efficient Pool Equipment	• Efficient Pool Pump Motors
New Construction	Tiers of Efficient New Construction	• 15% more efficient than standard home • 30% more efficient than standard home

6.2 RESIDENTIAL TECHNICAL AND ECONOMIC POTENTIAL SAVINGS

The technical potential represents the savings that could be captured if all inefficient electric appliances and equipment were replaced instantaneously (where they are deemed to be technically feasible). Table 6-3 indicates that the technical potential savings for the Big Rivers residential sector is 687,182 MWh, or 44.1% of forecast residential MWh sales in 2023. HVAC shell and equipment upgrades represent the greatest technical potential for electric savings. The technical potential for summer peak demand savings is approximately 161 MW, or 38.4% of 2023 forecast summer peak demand. The technical potential for winter peak demand savings is approximately 128 MW, or 31.4% of the 2023 winter peak demand forecast.

Table 6-3: Residential Sector Technical Potential Energy Savings by End Use

	Technical Potential		
	Energy (MWh)	**Winter Demand (MW)**	**Summer Demand (MW)**
Appliances	46,771	6.7	8.5
Electronics	24,158	2.4	2.7
Lighting	57,260	17.8	6.4
Water Heating	83,610	18.3	10.8
HVAC Envelope	201,655	54.8	71.7
HVAC Equipment	234,158	22.5	52.2
New Construction	19,952	3.7	2.7
Other	19,619	1.9	6.3
Total	**687,182**	**128**	**161**
Total, as % of 2023 Forecast	*44.1%*	*31.4%*	*38.4%*

The economic potential represents the savings that could be captured if all inefficient electric appliances and equipment were replaced instantaneously (where they are deemed to be economically feasible). Table 6-4 indicates that the economic potential savings for the Big Rivers residential sector is 625,263 MWh, or 40.1% of forecast residential MWh sales in 2023. HVAC shell and equipment upgrades represent the greatest economic potential for electric savings. The economic potential for summer peak demand savings is approximately 104 MW, or 24.7% of 2023 forecast summer peak demand. The economic potential for winter peak demand savings is approximately 125 MW, or 30.7% of the 2023 winter peak demand forecast.

Table 6-4: Residential Sector Economic Potential Energy Savings by End Use

	Economic Potential		
	Energy (MWh)	Winter Demand (MW)	Summer Demand (MW)
Appliances	45,414	6.6	8.3
Electronics	21,461	2.2	2.6
Lighting	57,260	17.8	6.4
Water Heating	55,100	8.3	6.3
HVAC Envelope	171,460	48.7	59.7
HVAC Equipment	229,819	35.6	10.9
New Construction	19,952	3.7	2.7
Other	24,798	2.5	6.9
Total	625,263	125	104
Total, as % of 2023 Forecast	*40.1%*	*30.7%*	*24.7%*

6.3 Residential Achievable Potential Savings

Achievable potential is a refinement of economic potential that takes into account the estimated market adoption of energy efficiency measures based on the incentive level and measure payback, the natural replacement cycle of equipment, and the capabilities of programs and administrators to ramp up program activity over time. Achievable potential also takes into account the non-measure costs of delivering programs (for administration, marketing, monitoring and evaluation, etc.). For purposes of this analysis, administrative costs were assumed to be equivalent to 20% of incremental measures costs. This is based on a published review of typical program administrator costs of several utility energy efficiency programs nationwide.[21]

6.3.1 Estimating Achievable Electric Potential Savings in the Residential Sector

As noted earlier in the report, there are more than 300 residential measures included in this study. Due to the wide variety of measures across multiple end-uses, the study employed varied, measure-specific maximum adoption rates versus a singular universal market adoption curve. These long-term market adoption estimates were based on publicly available DSM research including market adoption rate surveys and other utility program benchmarking.[22] Additional studies and alternate methods could produce different estimates of achievable potential.

For the majority of residential measures, the analysis assumes that increased incentives and reduced participant costs will also reduce the simple payback period of energy efficiency measures. As incentives increase and payback periods decline, maximum market adoption rates will increase. Based on available market adoption surveys with program administrators in the Northeast, GDS assigned end-use specific market adoption curves to the residential measures included in this analysis.[23] Once the long-term market

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[21] PacifiCorp Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources. Volume II. Prepared by Cadmus. March 2013. Appendix B-4, http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSMPotential_Vol-II_Mar2013.pdf

[22] Massachusetts Multifamily Market Characterization and Potential Study Volume I. May 2012. Cadmus Group. http://www.ma-eeac.org/Docs/8.1_EMV%20Page/2012/2012%20Residential%20Studies/Study%205_MA%20RR_LI%20-%20Multifamily%20Potential%20Study_FINAL_Report%20and%20Appendix_17MAY2012.pdf
& Appliance Recycling Program Process Evaluation and Market Characterization. Volume I. CALMAC Study ID# SCE0337.01. September 2012. Cadmus.
http://rtf.nwcouncil.org/subcommittees/fridgerecycle/SCE_PGE_ARP_Final_Report_Vol.1_09-18-13.pdf

[23] Massachusetts Multifamily Market Characterization and Potential Study Volume I. May 2012. Cadmus Group (see footnote 19 for link). This study presents market adoption curves based on the perspective of both multifamily property managers as well as utility energy efficiency program administrators. Both groups of study participants provide support for the contention that increased incentives/reduced payback result in higher maximum adoption rates. GDS selected the adoption curves based on the feedback of program administrators.

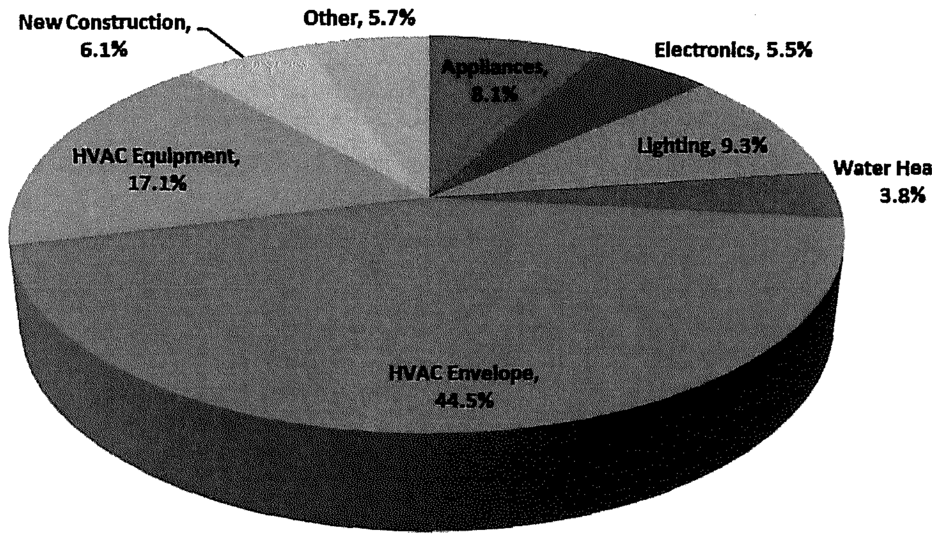
adoption rate was determined, GDS estimated the time interval required to reach the ultimate maximum adoption rate. In general, measures that required less up-front cost from the participant reached their maximum adoption rate over a period of 2-3 years, and continued at the maximum rate for the remainder of the study. Measures with a more substantial cost to the participant required more time to ramp-up, and would not reach their maximum adoption rate until later in the study period.

6.3.2 Residential Achievable Savings Potential

Figure 6-2 provides a detailed breakdown of the electric end-use savings as a percent of the total achievable potential. By 2023, the total residential energy efficiency achievable potential is 224,381 MWh, or 14.4% of forecast residential 2023 sales. The major opportunities for electricity efficiency resources are improved housing shell performance (i.e. duct sealing, insulation measures, reduced air infiltration, efficient windows, etc.) combined with more efficient heating and air conditioning equipment. As a fraction of total achievable savings potential in the residential sector, these efforts to reduce cooling and heating loads and improve HVAC system performance make up the largest majority (62%) of achievable savings potential.

It is important to note that the estimate of cumulative annual energy efficiency savings in 2023 accounts for known improvements to federal standards for equipment such as lighting and appliances. For instance, the incremental annual savings for lighting measures is necessarily higher in the early years of the study before declining after 2020 to account for the backstop provision of the EISA 2007[24].

Figure 6-2: Residential Sector End-use Savings as a % of Total Achievable Potential, 2023[25]



[24] The EISA 2007 includes a 2020 provision that is expected to make the baseline unit a CFL or bulb technology of similar efficacy. This will result in all savings associated with standard CFL bulbs replacing general service incandescent were modeled to decrease to 0 kWh by 2021. Standard LED bulb savings will also decrease in 2021.

[25] The "Weatherization Package" measure includes low flow faucet aerators and low flow showerheads. These components therefore boost the HVAC Envelope end-use savings, and the water heating end-use savings are decreased. Low flow devices were included in the Weatherization Package measure in the Achievable Potential scenario to align with current Big Rivers DSM program offerings.

Table 6-5 indicates that the achievable potential savings for the Big Rivers residential sector is 224,381 MWh, or 14.4% of forecast residential MWh sales in 2023. HVAC shell and equipment upgrades represent the greatest technical potential for electric savings. The achievable potential for summer peak demand savings is approximately 38 MW, or 9.0% of 2023 forecast summer peak demand. The achievable potential for winter peak demand savings is approximately 52 MW, or 12.7% of the 2023 winter peak demand forecast.

Table 6-5: Residential Sector Achievable Potential Energy Savings by End Use

	Achievable Potential		
	Energy (MWh)	**Winter Demand (MW)**	**Summer Demand (MW)**
Appliances	18,114	2.8	3.5
Electronics	12,235	1.4	1.7
Lighting	20,860	6.5	2.4
Water Heating	8,596	1.3	1.0
HVAC Envelope	99,848	32.0	22.2
HVAC Equipment	38,271	4.0	2.2
New Construction	13,630	2.5	1.9
Other	12,828	1.4	2.8
Total	224,381	52	38
Total, as % of 2023 Forecast	*14.4%*	*12.7%*	*9.0%*

6.4 Residential Annual Achievable Electric Savings Potential

Table 6-6 shows the cumulative annual energy savings (MWh) for the achievable potential scenario for each year across the 10-year time horizon for the study, broken out by end use. Table 6-7 and Table 6-8 shows cumulative annual winter and summer peak demand (MW) savings for the achievable potential scenario for each year across the 10-year time horizon for the study, broken out by end use.

Table 6-6: End Use Breakdown of Cumulative Annual Residential Energy Savings in the Achievable Potential Scenario

Cumulative Annual MWh Savings - Achievable										
End-Use	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Appliances	2,235	4,475	6,715	8,953	11,189	13,424	15,660	17,895	18,005	18,114
Electronics	2,346	4,760	7,192	9,613	10,143	10,573	10,985	11,402	11,821	12,235
Lighting	4,423	8,836	13,127	17,283	21,371	24,719	28,260	17,300	19,095	20,860
Water Heating	918	1,929	2,968	3,994	4,993	5,733	6,445	7,161	7,875	8,596
HVAC Envelope	11,055	22,128	33,198	44,265	55,322	66,378	77,434	79,893	89,872	99,848
HVAC Equipment	2,245	4,991	8,213	11,915	16,067	20,089	24,316	28,761	33,414	38,271
New Construction	1,313	2,806	4,271	5,691	7,032	8,366	9,707	11,049	12,358	13,630
Other	1,633	4,490	8,566	11,096	12,400	12,483	12,570	12,660	12,745	12,828
Total	**26,167**	**54,415**	**84,250**	**112,809**	**138,517**	**161,766**	**185,377**	**186,122**	**205,184**	**224,381**
% of Annual Forecast Sales	*1.8%*	*3.7%*	*5.8%*	*7.7%*	*9.4%*	*10.8%*	*12.3%*	*12.2%*	*13.3%*	*14.4%*

Table 6-7: End Use Breakdown of Cumulative Annual Residential Winter Peak Demand Savings in the Achievable Potential Scenario

Cumulative Annual Winter Peak Demand MW Savings - Achievable										
End-Use	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Appliances	0.3	0.7	1.0	1.3	1.6	2.0	2.3	2.6	2.7	2.8
Electronics	0.3	0.5	0.8	1.0	1.1	1.1	1.2	1.3	1.3	1.4
Lighting	1.3	2.6	3.9	5.1	6.2	7.2	8.1	5.4	6.0	6.5
Water Heating	0.1	0.3	0.5	0.6	0.8	0.9	1.0	1.1	1.2	1.3
HVAC Envelope	3.8	7.6	11.4	15.1	18.9	22.7	26.5	25.6	28.8	32.0
HVAC Equipment	0.3	0.6	1.0	1.4	1.9	2.2	2.6	3.1	3.5	4.0
New Construction	0.2	0.5	0.8	1.0	1.3	1.5	1.8	2.0	2.3	2.5
Other	0.2	0.5	0.9	1.2	1.4	1.4	1.4	1.4	1.4	1.4
Total	**6.5**	**13.3**	**20.2**	**26.9**	**33.2**	**39.0**	**44.9**	**42.5**	**47.2**	**51.9**
% of Annual Forecast Sales	*1.7%*	*3.5%*	*5.3%*	*7.0%*	*8.5%*	*9.9%*	*11.3%*	*10.6%*	*11.7%*	*12.7%*

Table 6-8: End Use Breakdown of Cumulative Annual Residential Summer Peak Demand Savings in the Achievable Potential Scenario

Cumulative Annual Summer Peak Demand MW Savings - Achievable										
End-Use	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Appliances	0.4	0.8	1.3	1.7	2.1	2.5	2.9	3.3	3.4	3.5
Electronics	0.3	0.6	0.9	1.2	1.3	1.3	1.4	1.5	1.6	1.7
Lighting	0.4	0.8	1.2	1.6	1.9	2.2	2.5	2.0	2.2	2.4
Water Heating	0.1	0.2	0.3	0.4	0.6	0.7	0.7	0.8	0.9	1.0
HVAC Envelope	3.3	6.7	10.0	13.4	16.7	20.1	23.4	17.7	19.9	22.2
HVAC Equipment	0.2	0.5	0.7	1.0	1.3	1.5	1.7	1.8	2.0	2.2
New Construction	0.2	0.4	0.6	0.8	1.0	1.1	1.3	1.5	1.7	1.9
Other	0.3	0.8	1.4	1.8	2.1	2.2	2.4	2.5	2.7	2.8
Total	**5.3**	**10.8**	**16.4**	**21.8**	**26.9**	**31.6**	**36.3**	**31.3**	**34.5**	**37.7**
% of Annual Forecast Sales	*1.4%*	*2.8%*	*4.2%*	*5.5%*	*6.7%*	*7.8%*	*8.9%*	*7.6%*	*8.3%*	*9.0%*

6.5 Residential Measure Level Detail

Table 6-9 below presents the measure-level technical, economic, and achievable MWh savings, sorted by end-use. Measures with significant remaining potential either possess significant per unit savings opportunities or are applicable to the majority of homes in the Big Rivers territory. For example, the weatherization package measure has a very high remaining potential because it has high savings and assumes that a significant percentage of homes could benefit from measures included in the weatherization package[26]. Measures with zero economic and achievable potential were not found to be cost effective.

In a few instances, a measure's economic potential is slightly greater than the technical potential. These adjusted savings in the economic potential scenario are due to a competing measure being dropped from the analysis after screening for cost-effectiveness. Additional measure detail for the technical, economic, and achievable potential in the residential sector can be found in Appendix A.

[26] Measures comprising the weatherization package measure were analyzed individually to calculate technical and economic potential estimates. The measures were combined to create a weatherization package measure which aligns with current Big Rivers DSM offerings.

Table 6-9: Residential Technical, Economic, and Achievable Savings Potential in 2023, by Measure (kWh)

Measure Name	Technical Potential	Economic Potential	Achievable Potential
Appliances			
ENERGY STAR Refrigerators	1,555,626	1,555,626	832,866
ENERGY STAR Freezers	1,357,383	0	0
ENERGY STAR Dehumidifiers	388,725	388,725	283,503
Refrigerator Recycling	34,735,008	34,735,008	13,584,032
Freezer Recycling	8,734,224	8,734,224	3,413,808
Electronics			
ENERGY STAR Televisions	4,855,061	4,855,061	4,311,014
ENERGY STAR Desktop Computer	5,464,074	5,464,074	1,705,627
ENERGY STAR Computer Monitor	392,378	392,378	258,230
ENERGY STAR Laptop	654,648	0	0
Smart Strip Power Strip	2,042,357	0	0
Efficient Set Top Box	10,749,652	10,749,652	5,960,164
Lighting			
Standard CFL	0	0	0
Standard LED	5,985,367	5,985,367	1,269,635
Specialty CFL	18,228,796	18,228,796	9,099,147
Specialty LED	25,820,018	25,820,018	7,401,506
ENERGY STAR Torchiere	4,826,871	4,826,871	2,455,223
LED Nightlight	327,542	327,542	40,637
Exterior CFL	0	0	0
Exterior LED	2,070,913	2,070,913	593,405
Water Heating			
Low Flow Faucet Aerators	2,366,578	2,366,578	533,490
Low Flow Showerheads	14,568,655	14,568,655	1,261,200
Water Heater Blanket	2,894,797	0	0
Water Heater Pipe Wrap	6,868,652	6,868,652	2,489,228
Heat Pump Water Heater	16,548,680	27,038,559	1,354,068
Solar Water Heaters	36,105,331	0	0
ENERGY STAR Dishwasher	556,074	556,074	312,867
ENERGY STAR Clothes Washer	3,701,307	3,701,307	2,644,912
HVAC Envelope			
Ceiling Insulation	76,284,800	76,733,547	31,204,566
Floor Insulation	54,818,864	54,818,864	19,412,397
ENERGY STAR Windows	28,961,923	423,077	228,570
Air Sealing	12,978,569	10,873,662	3,715,610
Duct Sealing	10,006,358	10,006,358	1,066,404
Radiant Barriers	18,604,562	18,604,562	106,262
Weatherization Package	0	0	44,114,135
HVAC Equipment			
HVAC Tune-up	2,114,601	4,943,821	2,097,565
ENERGY STAR Room Air Conditioner	569,620	0	0
High Efficiency Central Air Conditioner	10,774,135	0	0
Ductless minisplit AC or HP	50,282,878	0	0
High Efficiency Air-Source Heat Pump	55,834,500	35,888,958	3,605,598
Geothermal Heat Pump	18,954,483	0	0
Dual Fuel Heat Pump	49,897,211	135,947,789	11,696,120
ECM Furnace Fan	14,422,847	16,952,823	5,794,729
Programmable or Smart Thermostats	31,307,662	36,085,736	15,076,838
New Construction			
New Construction 15% more efficient	6,650,557	6,650,557	4,543,282
New Construction 30% more efficient	13,301,113	13,301,113	9,086,565
Other			
Home Energy Display Monitor	12,390,020	20,582,886	10,953,145
Home Energy Reports	4,557,757	1,543,765	979,814
Efficient Pool Pumps	2,554,094	2,554,094	858,647
Multi-Family Homes Efficiency Kit	117,137	117,137	35,904
Total	687,182,405	625,262,827	224,380,715
% of Annual 2023 Sales Forecast	44.1%	40.1%	14.4%

6.6 Residential Achievable Potential Benefits and Costs

Table 6-10 below provide the net present value (NPV) benefits and costs associated with the achievable potential scenarios for the residential sector over the 10-year timeframe of the study.

Table 6-10: 10-Year Benefit-Cost Ratios for the Achievable Potential Scenario – Residential sector

10-Year	NPV Benefits	NPV Costs	B/C Ratio	Net Benefits
Achievable Potential	$408,357,173	$181,454,077	2.25	$226,903,095

The NPV costs of $181 million include both total measure costs (incentives plus participant), as well as program delivery costs (i.e. marketing, labor, monitoring, etc.) of administering energy efficiency programs between 2014 and 2023. The net present value benefits of $408 million represent the lifetime benefits of all measures installed during the same time period. Thus, while the achievable potential estimates would assume a substantial investment in energy efficiency from both Big Rivers and its Members, the estimated energy and demand savings would result in net benefits of nearly $227 million.

7 COMMERCIAL ELECTRIC EFFICIENCY POTENTIAL ESTIMATES

Figure 7-1 and Table 7-1 presented below, summarize the technical, economic, and achievable savings potential for the Big Rivers service area by 2023.

The potential estimates are expressed as cumulative 10-year savings, as percentages of 2023 sector sales. The technical potential is 31.0% in 2023. The 10-year economic potential is 27.7% based on the TRC test screening, assuming an incentive level equal to 35% of the measure cost for most measures. The 10-year achievable potential savings is 8.3% of 2023 sector sales.

Energy efficiency measures and programs can also serve to lessen peak demand. The estimated peak demand savings in the achievable potential scenario are 5.3% of forecasted winter peak demand in 2023 and 10.3% of forecasted summer demand in 2023.

Figure 7-1: 2023 Summary of Cumulative C&I Energy Efficiency Potential

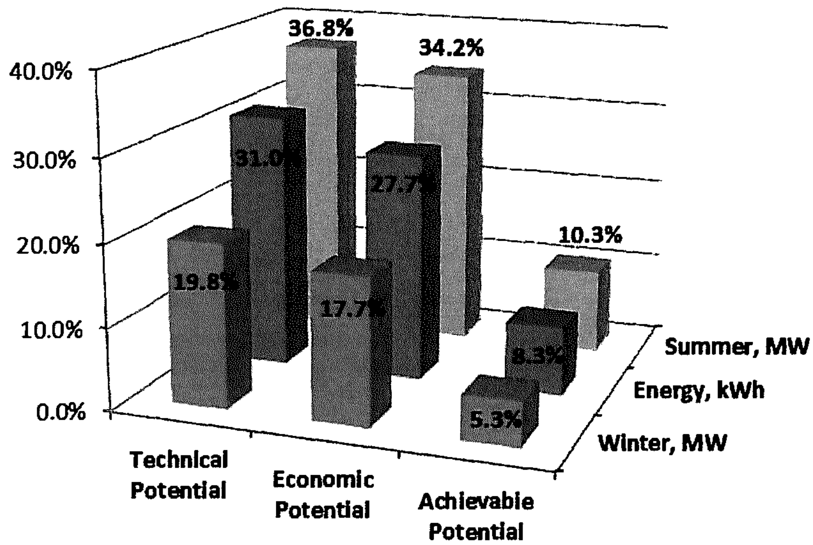


Table 7-1: 2023 Summary of Cumulative C&I Energy and Demand Savings Potential

	Energy		Demand			
	MWh	% of 2023 MWh Sales	Winter MW	% of 2023 Winter Peak	Summer MW	% of 2023 Summer Peak
BIG RIVERS TERRITORY						
Technical Potential	539,828	31.0%	48	19.8%	95	36.8%
Economic Potential	481,701	27.7%	43	17.7%	88	34.2%
Achievable Potential	144,510	8.3%	13	5.3%	26	10.3%

7.1 Commercial & Industrial Energy Efficiency Measures Examined

For the commercial and industrial, there were 79 total electric savings measures included in the potential energy savings analysis[27]. Table 7-2 provides a brief description of the types of measures included for each end use in the commercial and industrial model. The list of measures was developed based primarily on a review of the Indiana Technical Reference Manual (IN TRM) and measures found in other residential potential studies and other TRMs for states and regions near Kentucky. Measure data includes incremental costs, electricity energy and demand savings, gas and water savings, and measure life.

Table 7-2: Measures and Programs Included in the Electric C&I Sector Analysis

End Use Type	End Use Description	Measures Included
Lighting	Interior / Exterior Lighting; Sensors	• Lighting Sensors • T5 and T8HO Fluorescent Fixture Bulbs • CFL Fixtures and Screw-in Bulbs • LED High Bay, Low Bay and Exit Signs • Outdoor Lighting – LED and Induction (unmetered)
Space Cooling	HVAC Cooling Equipment	• Air Cooled Chiller • DX Packaged AC • Split AC • Packaged Terminal AC (PTAC) • HVAC Tune-Up
Space Heating	HVAC Heating Equipment	• Packaged Terminal Heat Pump (PTHP)
Motors	Ventilation, and Non-Ventilation	• Variable Frequency Drives (VFDs)
Water Heating	Commercial / Industrial Hot Water Heating	• High Efficiency Storage Tank Water Heater • Water Heater Tank Insulation • On Demand (Tankless) Water Heater • Pre-Rinse Low Flow Sprayer • Heat Pump Water Heater
Cooking	Commercial / Industrial Cooking	• Efficient Cooking Equipment
Refrigeration	Commercial / Industrial Refrigeration	• Anti-sweat Controls • Fan Controls • Economizers • Strip Curtains • Display Case Covers • Compressor Motors • Vending Misers
Other	Miscellaneous	• Fix Compressed Air Leaks • Engineered Nozzles for Blow-Off Valves • Watt Sensors for Office Electronics

7.2 Commercial & Industrial Technical and Economic Potential Savings

The technical potential represents the savings that could be captured if all inefficient electric appliances and equipment were replaced instantaneously (where they are deemed to be technically feasible). Table 7-3 indicates that the technical potential savings for the Big Rivers non-residential sector is 539,828 MWh, or 31.0% of forecast residential MWh sales in 2023. Lighting and refrigeration upgrades represent the greatest technical potential for electric savings. The technical potential for summer peak demand savings is approximately 95 MW, or 36.8% of 2023 forecast summer peak demand. The technical potential for

[27] This total represents the number of unique electric energy efficiency measures and all permutations of these unique measures.

winter peak demand savings is approximately 48 MW, or 19.8% of the 2023 winter peak demand forecast.

Table 7-3: C&I Sector Technical Potential Energy Savings by End Use

	Technical Potential		
	Energy (MWh)	**Winter Demand (MW)**	**Summer Demand (MW)**
Space Heating	3,846	0.3	0.0
Cooling	54,533	0.0	25.8
Ventilation	26,029	5.1	7.4
Water Heating	22,493	1.5	2.5
Lighting	327,500	28.6	45.3
Cooking	2,729	0.0	1.1
Refrigeration	76,380	11.1	11.5
Office Equipment	11,179	0.9	0.0
Other	15,139	0.9	1.5
Total	**539,828**	**48**	**95**
Total as % of 2023 C&I Forecast	*31.0%*	*19.8%*	*36.8%*

The economic potential represents the savings that could be captured if all inefficient electric appliances and equipment were replaced instantaneously (where they are deemed to be economically feasible). Table 7-4 indicates that the economic potential savings for the Big Rivers non-residential sector is 481,701 MWh, or 27.7% of forecast residential MWh sales in 2023. Lighting and refrigeration upgrades represent the greatest economic potential for electric savings. The economic potential for summer peak demand savings is approximately 88 MW, or 34.2% of 2023 forecast summer peak demand. The economic potential for winter peak demand savings is approximately 43 MW, or 17.7% of the 2023 winter peak demand forecast.

Table 7-4: C&I Sector Economic Potential Energy Savings by End Use

	Economic Potential		
	Energy (MWh)	**Winter Demand (MW)**	**Summer Demand (MW)**
Space Heating	3,846	0.3	0.0
Cooling	54,533	0.0	25.8
Ventilation	26,029	5.1	7.4
Water Heating	22,493	1.5	2.5
Lighting	291,614	24.9	39.4
Cooking	2,729	0.0	1.1
Refrigeration	66,106	10.6	10.9
Office Equipment	0	0.0	0.0
Other	14,352	0.9	1.2
Total	**481,701**	**43**	**88**
Total as % of 2023 C&I Forecast	*27.7%*	*17.7%*	*34.2%*

7.3 Commercial & Industrial Achievable Potential Savings

Achievable potential is a refinement of economic potential that takes into account the estimated market adoption of energy efficiency measures based on the incentive level and measure payback, the natural replacement cycle of equipment, and the capabilities of programs and administrators to ramp up program activity over time. Achievable potential also takes into account the non-measure costs of delivering programs (for administration, marketing, monitoring and evaluation, etc.). For purposes of this analysis, administrative costs were assumed to be 20% of the budget with the remaining 80% of the budget allocated for rebate costs. This is based on a published review of typical program administrator costs of several utility energy efficiency programs nationwide.[28]

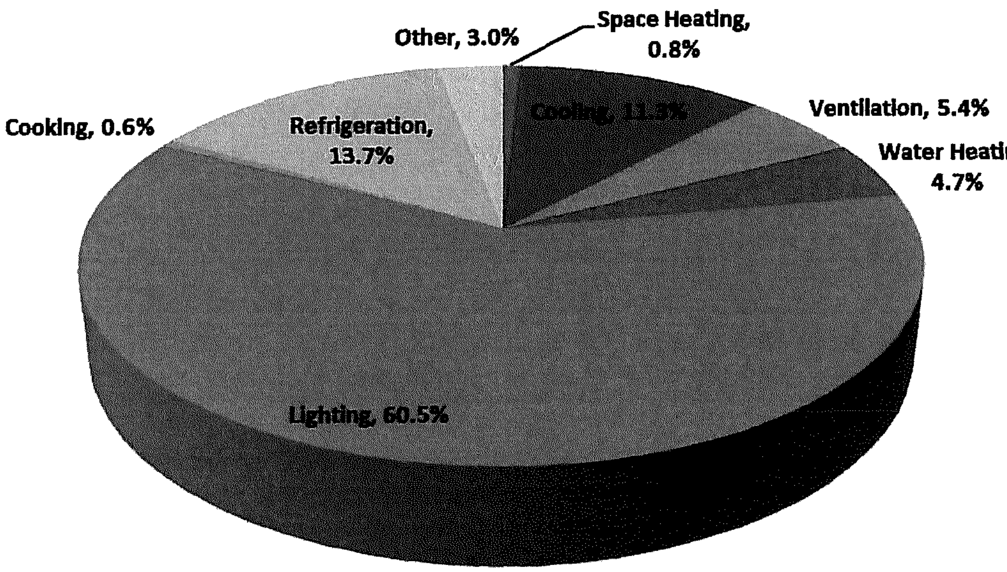
7.3.1 Estimating Achievable Electric Potential Savings in the Commercial & Industrial Sector

In the base case scenario, the commercial and industrial achievable potential represents the attainable savings if the market penetration of high efficiency electric equipment reaches 30% of the remaining eligible market between 2014 and 2023. The methodology for estimating energy efficiency measure adoption in the commercial and industrial sector each year from 2014 through 2023 is based on a constant ramp in rate of 10% a year. Because of the "top-down" methodology, the number of customers is difficult to determine. Program implementation experience shows a more rapid increase of program participation in the first 4 years, tapering off in the remaining 6 years. With new technologies, there is often low awareness of the technology among consumers and there may be a hesitancy to purchase the technology because of its newness. A program could then be designed to not only provide incentives, but to increase awareness and promote the technology's reliability. In contrast, a mature technology may already have high willingness and awareness values and, thus, the adoption curve would follow a flatter trend over time.

7.3.2 Commercial & Industrial Achievable Savings Potential

Figure 7-2 provides a detailed breakdown of the electric end-use savings as a percent of the total achievable potential. By 2023, the total C&I energy efficiency achievable potential is 144,510 MWh, or 8.3% of forecast non-residential 2023 sales. The major opportunities for electricity efficiency resources are improved lighting and refrigeration. As a fraction of total achievable savings potential in the non-residential sector, these efforts are estimated to make up nearly 75% of achievable savings potential.

Figure 7-2: Residential Sector End-use Savings as a % of Total Achievable Potential, 2023



[28] PacifiCorp Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources. Volume II. Prepared by Cadmus. March 2013. Appendix B-4 (see footnote 19 for link).

Table 7-5 indicates that the achievable potential savings for the Big Rivers non-residential sector is 144,510 MWh, or 8.3% of forecast non-residential MWh sales in 2023. The achievable potential for summer peak demand savings is approximately 26 MW, or 10.3% of 2023 forecast summer peak demand. The achievable potential for winter peak demand savings is approximately 13 MW, or 5.3% of the 2023 winter peak demand forecast.

Table 7-5: C&I Sector Achievable Potential Energy Savings by End Use

	Achievable Potential		
	Energy (MWh)	**Winter Demand (MW)**	**Summer Demand (MW)**
Space Heating	1,154	0.1	0.0
Cooling	16,360	0.0	7.7
Ventilation	7,809	1.5	2.2
Water Heating	6,748	0.4	0.7
Lighting	87,484	7.5	11.8
Cooking	819	0.0	0.3
Refrigeration	19,832	3.2	3.3
Office Equipment	0	0.0	0.0
Other	4,305	0.3	0.4
Total	144,510	13	26
Total as % of 2023 C&I Forecast	*8.3%*	*5.3%*	*10.3%*

7.4 Commercial & Industrial Annual Achievable Electric Savings Potential

Table 7-6 shows the cumulative annual energy savings (MWh) for the achievable potential scenario for each year across the 10-year time horizon for the study, broken out by end use. Table 7-7 and Table 7-8 shows cumulative annual winter and summer peak demand (MW) savings for the achievable potential scenario for each year across the 10-year time horizon for the study, broken out by end use.

Table 7-6: End Use Breakdown of Cumulative Annual Non-Residential Energy Savings in the Achievable Potential Scenario

Cumulative Annual MWh Savings - Achievable										
End-Use	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Space Heating	115	231	346	461	577	692	808	923	1,038	1,154
Cooling	1,636	3,272	4,908	6,544	8,180	9,816	11,452	13,088	14,724	16,360
Ventilation	781	1,562	2,343	3,123	3,904	4,685	5,466	6,247	7,028	7,809
Water Heating	675	1,350	2,024	2,699	3,374	4,049	4,723	5,398	6,073	6,748
Lighting	8,748	17,497	26,245	34,994	43,742	52,491	61,239	69,987	78,736	87,484
Cooking	82	164	246	328	409	491	573	655	737	819
Refrigeration	1,983	3,966	5,950	7,933	9,916	11,899	13,882	15,865	17,849	19,832
Office Equipment	0	0	0	0	0	0	0	0	0	0
Other	431	861	1,292	1,722	2,153	2,583	3,014	3,444	3,875	4,305
Total	**14,451**	**28,902**	**43,353**	**57,804**	**72,255**	**86,706**	**101,157**	**115,608**	**130,059**	**144,510**
% of Annual Forecast Sales	*0.8%*	*1.7%*	*2.6%*	*3.4%*	*4.2%*	*5.1%*	*5.9%*	*6.7%*	*7.5%*	*8.3%*

Table 7-7: End Use Breakdown of Cumulative Annual Non-Residential Winter Peak Demand Savings in the Achievable Potential Scenario

Cumulative Annual Winter Peak Demand MW Savings - Achievable										
End-Use	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Space Heating	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Cooling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ventilation	0.2	0.3	0.5	0.6	0.8	0.9	1.1	1.2	1.4	1.5
Water Heating	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.4	0.4
Lighting	0.7	1.5	2.2	3.0	3.7	4.5	5.2	6.0	6.7	7.5
Cooking	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refrigeration	0.3	0.6	1.0	1.3	1.6	1.9	2.2	2.6	2.9	3.2
Office Equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3
Total	**1.3**	**2.6**	**3.9**	**5.2**	**6.5**	**7.8**	**9.1**	**10.4**	**11.7**	**13.0**
% of Annual Forecast	*0.6%*	*1.1%*	*1.7%*	*2.2%*	*2.7%*	*3.3%*	*3.8%*	*4.3%*	*4.8%*	*5.3%*

Table 7-8: End Use Breakdown of Cumulative Annual Non-Residential Summer Peak Demand Savings in the Achievable Potential Scenario

CUMULATIVE ANNUAL SUMMER PEAK DEMAND MW SAVINGS - ACHIEVABLE										
End-Use	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Space Heating	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cooling	0.8	1.5	2.3	3.1	3.9	4.6	5.4	6.2	7.0	7.7
Ventilation	0.2	0.4	0.7	0.9	1.1	1.3	1.6	1.8	2.0	2.2
Water Heating	0.1	0.1	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.7
Lighting	1.2	2.4	3.5	4.7	5.9	7.1	8.3	9.5	10.6	11.8
Cooking	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3
Refrigeration	0.3	0.7	1.0	1.3	1.6	2.0	2.3	2.6	2.9	3.3
Office Equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.4
Total	**2.6**	**5.3**	**7.9**	**10.6**	**13.2**	**15.9**	**18.5**	**21.2**	**23.8**	**26.5**
% of Annual Forecast	*1.1%*	*2.1%*	*3.2%*	*4.2%*	*5.3%*	*6.3%*	*7.3%*	*8.3%*	*9.3%*	*10.3%*

7.5 Commercial & Industrial Measure Level Detail

Table 7-9 below presents the measure-level technical, economic, and achievable MWh savings, sorted by end-use. Measures with zero economic and achievable potential were not found to be cost effective.

In a few instances, a measure's economic potential is slightly greater than the technical potential. These adjusted savings in the economic potential scenario are due to a competing measure being dropped from the analysis after screening for cost-effectiveness. Additional measure detail for the technical, economic, and achievable potential in the residential sector can be found in Appendix B and Appendix C.

Table 7-9: Non-Residential Technical, Economic, and Achievable Savings Potential in 2023, by Measure (MWh)

MEASURE NAME	TECHNICAL POTENTIAL	ECONOMIC POTENTIAL	ACHIEVABLE POTENTIAL
Lighting			
Occupancy Sensors	107,618	107,618	32,285
Compact Fluorescents	53,973	53,973	16,192
Low Bay LED, High Bay LED	48,227	48,227	14,468
Outdoor LED or Induction	39,532	39,532	11,860
High Bay T8VHO	34,564	19,051	5,715
High Performance T8 and T5	24,910	4,537	1,361
CFL Hard Wired Fixture	17,283	17,283	5,185
LED Exit Sign	1,393	1,393	418
Space Cooling			
DX Packaged Systems	17,509	17,509	5,253
Air Cooled Chillers	17,347	17,347	5,204
Packaged Terminal AC	12,632	12,632	3,790
Split Air Conditioning	6,197	6,197	1,859
HVAC Tune-up	847	847	254
Space Heating			
Packaged Terminal Heat Pump	3,846	3,846	1,154
Motors (Ventilation and Non-Ventilation)			
Variable Frequency Drives	39,150	39,150	11,745
Water Heating			
Heat Pump Water Heater	10,774	10,774	3,232
Tank Insulation	5,304	5,304	1,591
Pre-Rinse Sprayer, Low flow, Commercial Application	5,229	5,229	1,569
High Efficiency Storage (tank)	1,050	1,050	315
On Demand (tankless)	136	136	41
Cooking			
Energy Star Hot Food Holding Cabinet	889	889	267
Energy Star Convection Ovens	674	674	202
Electric Energy Star Steamers,3-6 pan	663	663	199
Electric Energy Star Fryers & Griddles	503	503	151
Refrigeration			
Anti-sweat Heater Controls Refrigerators & Freezers	17,025	17,025	5,108
Solid Door Refrigerators & Freezers	10,680	10,680	3,204
Evaporator Coil Defrost Control	9,095	9,095	2,729
Glass Door Refrigerators & Freezers	7,614	7,614	2,284
Evaporator Fan Motor Control for freezers and coolers	6,969	0	0
Brushless DC Motors for freezers and coolers	6,544	6,544	1,963
Humidity Door Heater Controls for freezers and coolers	6,398	6,398	1,920
Commercial Refrigeration Tune-Up	4,537	2,392	717
Vending Miser, Cold Beverage	3,875	3,875	1,163

MEASURE NAME	TECHNICAL POTENTIAL	ECONOMIC POTENTIAL	ACHIEVABLE POTENTIAL
Lighting			
Zero Energy Doors for freezers and coolers	1,627	1,627	488
Ice Machine, Energy Star, Self-Contained	855	855	257
Refrigerated Case Covers	668	0	0
LED Case Lighting (5 door case)	492	0	0
Office Equipment/Compressed Air			
Watt Sensors on Office Electronics	11,179	0	0
Fix Air Leaks	1,984	1,197	359
Engineered Nozzles for blow-off	33	33	10
Total	**539,828**	**481,701**	**144,510**
% of Annual 2023 Sales Forecast	**31.0%**	**27.7%**	**8.3%**

7.6 Commercial & Industrial Achievable Potential Benefits and Costs

Table 7-10 below provide the net present value (NPV) benefits and costs associated with the achievable potential scenarios for the non-residential sector over the 10-year timeframe of the study.

Table 7-10: 10-Year Benefit-Cost Ratios for the Achievable Potential Scenario – Non-residential sector

10-YEAR	NPV BENEFITS	NPV COSTS	B/C RATIO	NET BENEFITS
Achievable Potential	$98,434,083	$55,031,979	1.79	$43,402,103

The NPV costs of $55 million include both total measure costs (incentives plus participant), as well as program delivery costs (i.e. marketing, labor, monitoring, etc.) of administering energy efficiency programs between 2014 and 2023. The net present value benefits of $98 million represent the lifetime benefits of all measures installed during the same time period. Thus, while the achievable potential estimates would assume a substantial investment in energy efficiency from both Big Rivers and its Members, the estimated energy and demand savings would result in net benefits of more than $43 million.

8 DEMAND RESPONSE ANALYSIS

In an August 2006 report by staff to the FERC, a definition of "demand response" ("DR") was adopted by the Commission. This definition was used earlier by the U.S. Department of Energy ("DOE") in its February 2006 report to Congress:

> *Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*[29]

In their August 2006 report FERC staff noted that demand response is an active response to prices or incentive payments. The changes in electricity use are designed to be short-term in nature, centered on critical hours when demand or market prices are high, or when reserve margins are low. This is contrasted to energy efficiency programs that are focused on longer-term responses or reduction in consumption through the investment in energy efficient equipment or change in behavior.

8.1 TYPES OF DEMAND RESPONSE

There are generally two major types of demand response programs: incentive-based programs and time-based programs. Incentive-based programs generally involve the utility paying an incentive to a retail customer to reduce peak demand or allow for direct control of end use appliances. Such programs include direct load control, interruptible programs, demand buy-back, and emergency demand response. Time-based programs include a suite of rate alternatives known as dynamic pricing. These programs have rates that incentivize customers to reduce loads during certain times of the day and year (critical peaking hours). Time-based programs include time-of-use, critical peak pricing, and real time pricing rates.

For incentive-based programs, generally the goal is for the load reduction to act as a resource, i.e., the demand reduction occurs via dispatch by the system operator. With this treatment, the demand reduction capability can be included in the resource portfolio. The resources can be dispatched for a number of reasons including peak load, low reserves, high energy costs, and transmission line loading.

The goal with price-based incentives is to provide a price signal that is reflective of current market conditions and the demand reductions occur as a voluntary response to the price signal. Generally, these types of responses are embedded in the load forecast, and not explicitly modeled. While it is often a concern that the load response is not as "firm" as with incentive-based programs, the response can become more predictable based on weather, foreknowledge of prices, and experience.

8.2 GENERAL BENEFITS OF DEMAND RESPONSE

Customer responses under demand response programs can either reduce or shift consumption during high cost periods. While all of the programs evaluated within this project result in reducing the load requirements of the system during certain peak periods, there are two distinct load impacts that can result.

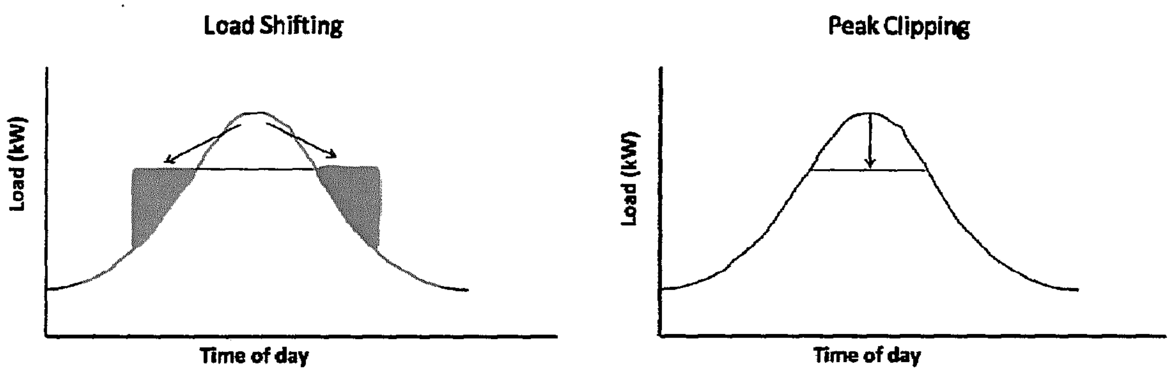
"Load Shifting" – Projects that move energy consumption from one time to another (usually during a single day).

"Peak Clipping" – Projects that reduce energy demand at certain critical times, with no recovery of the energy at a later time.

[29] U.S. Department of Energy, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006 (February 2006 DOE EPAct Report), http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/DOE_Benefits_of_Demand_Response_in_Electricity_Markets_and_Recommendations_for_Achieving_Them_Report_to_Congress.pdf

Demand response can provide the benefit of serving as a substitute for peaking generation resources. In addition, it can reduce the need for expansion in distribution investment. Demand response also has the potential to reduce energy supply costs and, in general, electricity price volatility. Finally, demand response can also serve as supplemental (non-spinning) operating reserves.

Figure 8-1: Load Shifting and Peak Clipping Program



8.3 ENHANCEMENTS OF RESPONSE WITH TECHNOLOGY

Automated technology enhances the responsiveness of a facility participating in a demand response program by enabling the customer to achieve a higher percentage of its load reduction potential. Studies conducted by the Rocky Mountain Institute[30] indicate that technology appears to be an important driver in reducing load, especially the most critical peaks for consumers within a rate class that have the highest levels of consumption. Automated technology can help produce consistent load reductions across the cooling season. For example, large commercial and industrial customers show the greatest price elasticity with their ability and willingness to respond to incentives, but without automation the response is uneven, with the load reductions coming from backup generation, shifting operations, or manually shutting off loads in a less organized manner.

Automated metering infrastructure ("AMI") technology can combine load management capabilities with alternative retail rate structures, in addition to providing the benefits of improved meter reading, outage management and power quality, as well as reducing theft. AMI can provide the first step in having the necessary technology in place to support demand response efforts. As an example, with AMI, time-based rates can be offered without the additional cost of interval metering, normally a barrier in the implementation of Time-Of-Use ("TOU") rates. Additionally, with AMI, load control can be initiated via power line carrier technology with load control operations coinciding with on-peak or critical peak price periods achieving a greater load impact than if a manual response was required by the customer.

8.4 CURRENT DEMAND RESPONSE PROGRAMS

Big Rivers does not currently operate any direct control programs and does not provide electric service to any retail or wholesale customers under an interruptible or curtailable contract or tariff. Big Rivers offers a Voluntary Curtailment Rider, which provides a means for potentially reducing system peak demand during peak periods. In the last fourteen years, there have been four curtailments affecting two commercial customers. The maximum estimated load reduction due to the two voluntary curtailment customers is 20-25 MW.

[30] "Demand Response: An Introduction", Rocky Mountain Institute, April 30, 2006, http://www.ceeforum.org/content/demand-response-introduction-overview-programs-technologies-and-lessons-learned

Table 8-1: 2000-2010 Voluntary Industrial Curtailment Results

Year	*Number of Curtailments*	*Load Reduction (MW)*
2000	*0*	*n/a*
2001	*0*	*n/a*
2002	*0*	*n/a*
2003	*0*	*n/a*
2004	*0*	*n/a*
2005	*0*	*n/a*
2006	*0*	*n/a*
2007	*0*	*n/a*
2008	*1*	*20*
2009	*3*	*1 to 25*
2010	*0*	*n/a*
2011	*0*	*n/a*
2012	*0*	*n/a*
2013	*0*	*n/a*

8.5 MISO Demand Response

MISO allows for demand response participation in the market through various means, including participation as a load modifying resource ("LMR"), as demand response resource ("DRR") and as emergency demand response ("EDR"). Participation in such programs requires meeting various operational, registration, and credit requirements. For DRR and LMR, the payments received are based on how the resource is used and includes energy costs via the LMP and possibly make-whole payments, operating reserves, or planning resources. EDR payment is based on LMP or production costs (shut-down costs of production unit plus a curtailment energy offer that is made). By using MISO market prices as the proxy for demand response resources, Big Rivers is appropriately assessing the value of DR in the MISO market.

8.6 Demand Response Programs Evaluated

A list of potential DR programs representing the most common and most likely to be cost-effective were evaluated in this screening analysis. Big Rivers focused the analysis on the most common types of programs that a utility might use in starting a demand response initiative. If more of these programs passed the screening, the list of potential programs for screening would have been expanded. Programs not included initially, but that could have been considered if further analysis was warranted include, but are not limited to: dual fuel heat pumps, electric thermal storage ("ETS") heating units for residences, ETS cooling units for commercial buildings, direct control of swimming pool pumps, and direct control of agricultural applications such as irrigators and grain dryers.

A total of fifteen programs were evaluated, with a mix of both residential and commercial incentive-based and price-based programs. Consistent with the energy efficiency evaluation, DR programs are primarily evaluated based on the TRC test, but UCT and PCT were also calculated.

Table 8-2: Demand Response Programs Evaluated Results

Sector	Program	Basis	Peak Effect	Direct Control	Summer kW Savings per Unit	Winter kW Savings per Unit
Residential	Air Conditioner - 33% Cycling	Incentive	Peak Shift	Yes	0.8	0.0
	Air Conditioner - 50% Cycling	Incentive	Peak Shift	Yes	1.1	0.0
	Water Heater - 40/50 Gallon	Incentive	Peak Shift	Yes	0.4	0.6
	Time-of-Use (TOU) Rate	Price	Peak Shift	No	0.2	0.1
	Crticial Peak Pricing (CPP) Rate	Price	Peak Shift	No	1.0	0.5
	Smart Thermostat w/ CPP Rate	Incentive/Price	Peak Shift	Yes	1.4	0.5
Commercial	Distributed Generation	Incentive	Peak Clip	Yes	350	350
	Lighting - Small Application	Incentive	Peak Clip	Yes	2.1	2.1
	Lighting - Large Application	Incentive	Peak Clip	Yes	21	21
	Energy Management System (EMS)	Incentive	Peak Shift	No	12	12
	Time-of-Use (TOU) Rate	Price	Peak Shift	No	0.1	0.1
	Crticial Peak Pricing (CPP) Rate	Price	Peak Shift	No	0.6	0.6
Industrial	Distributed Generation	Incentive	Peak Clip	Yes	1,000	1,000
	Energy Management System (EMS)	Incentive	Peak Shift	No	150	150
	Interruptible Rate	Price	Peak Clip	No	1,000	1,000

8.7 Demand Response Cost-Effectiveness

Due to the low value currently associated with avoided production and transmission capacity, most of the DR programs evaluated are not cost effective under the TRC test. The table below presents the 10-year net present value benefits and costs for a single unit and shows the benefit/cost ratios for the TRC test. The methodology employed in calculating these effectiveness tests is consistent with the methodology employed in evaluating energy efficiency as described earlier in this report. Further details on inputs into the analysis including load, benefit, and cost assumptions are described below.

Table 8-3: Cost-Effectiveness Screening Results per DR Measure Installed

		Total Resource Cost Test		
	Program	NPV Benefits	NPV Costs	TRCT
Residential	Air Conditioner - 33% Cycling	$232	$693	0.33
	Air Conditioner - 50% Cycling	$345	$784	0.44
	Water Heater - 40/50 Gallon	$366	$820	0.45
	Smart Thermostat	$615	$995	0.62
	Time-of-Use (TOU) Rate	$123	$271	0.45
	Crticial Peak Pricing (CPP) Rate	$517	$680	0.76
Commercial	Distributed Generation	$222,915	$238,469	0.93
	Lighting - Small Application	$1,324	$1,825	0.73
	Lighting - Large Application	$13,096	$12,823	**1.02**
	Energy Management System (EMS)	$6,541	$13,879	0.47
	Time-of-Use (TOU) Rate	$119	$926	0.13
	Crticial Peak Pricing (CPP) Rate	$535	$1,013	0.53
Industrial	Distributed Generation	$438,011	$698,456	0.63
	Energy Management System (EMS)	$56,479	$229,289	0.25
	Interruptible Rate	$361,121	$238,536	**1.51**

8.8 Key Assumptions and Inputs

The demand response analysis is consistent with the energy efficiency analysis in many respects. The same screening model is used to calculate the evaluation metrics for the TRC Test. Key input system data such as the load forecast, loss factors, reserve margins, transmission and distribution avoided costs, and discount factors are also consistent between the Energy Efficiency and Demand Response analyses. This section details the assumptions that are specific to demand response programs.

Load Impacts

One of the critical assumptions for screening demand response programs is the amount of load reduction possible at the time of the system peak. A body of secondary research sources and GDS' experience with other cooperatives were used to develop load impact assumptions for Big Rivers.

Air Conditioners – For air conditioners, the study used load impact estimates from potential studies for utilities in four other states. The load estimates were weather-adjusted by developing a linear regression relationship between normal cooling degree days and the load impact. The regression model and cooling degree days for Big Rivers were used to estimate air conditioner impacts in Kentucky. These were then checked for reasonableness with measurement and verification study results in the secondary literature. The impacts for the proxy utilities in other states were developed using system specific data including weather, size of home, and estimation techniques suggested by the Air Conditioning Contractors of America ("ACCA").[31]

Water Heaters – Water heaters are estimated in a manner similar to air conditioners, averaging load impacts seen in other GDS studies. However, water heaters are not as weather-sensitive and the estimates are very stable from region to region.

Residential and Commercial Rate Programs – There are three residential rate programs that build upon each other: Time of Use ("TOU"), Critical Peak Pricing ("CPP") interactive metering (manual control by consumer), and CPP smart thermostat (control by utility).

TOU rates have fixed prices for defined time periods. The CPP rates would have fixed prices for off-peak hours and defined on-peak periods. In addition, there are higher (critical) prices during select high energy cost hours. For this study, the top 100 energy cost hours are assumed for the CPP rate. For the CPP manual program, the residential user has a programmable thermostat and can choose to respond to prices, but there is no control from the utility. With the smart thermostat program, the utility can control the air conditioner and, therefore, achieve load impacts consistent with an AC control program plus additional benefits associated with customer response to prices. Figure 8.2 on the following page demonstrates theoretical time-based rates for a summer day.

[31] "Manual S – Residential Equipment Selection." ACCA.

Figure 8-2: Example Time-Based Rates on a Summer Day

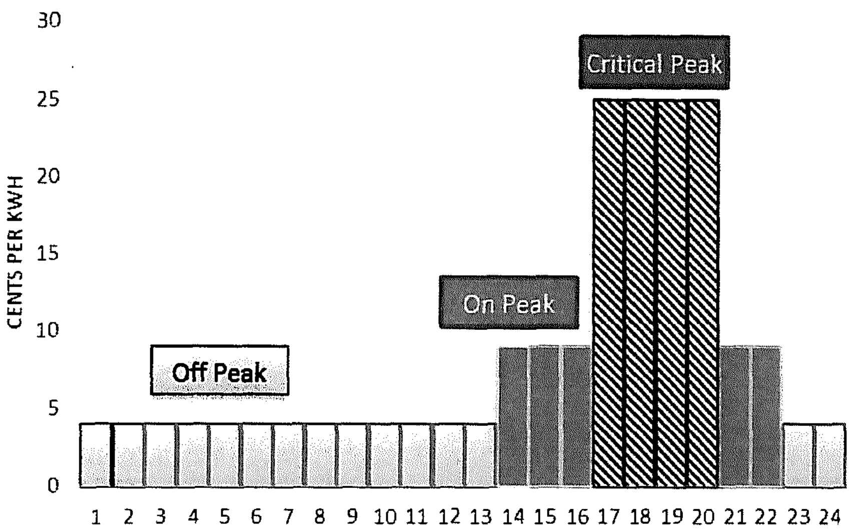
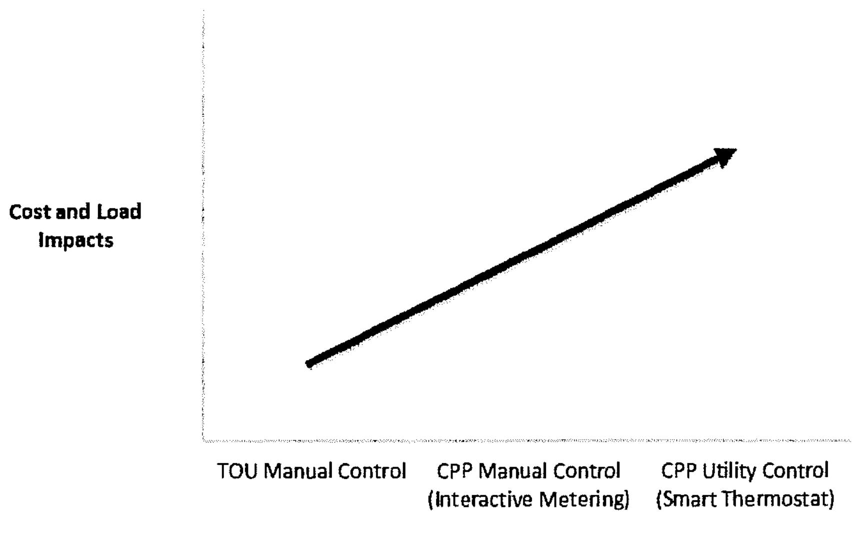


Figure 8-3 demonstrates the relationship between program costs and load impacts for the three rates. The TOU rate with manual control[32] has the lowest equipment and administrative costs but also provides the least demand response since it is based on voluntary response. The CPP rate with manual control provides a stronger price signal and therefore gets a slightly better energy and demand benefit, but costs are also higher than the TOU rate because of the need for equipment to send price signals during critical peak pricing hours. Finally, the addition of a smart thermostat that allows the utility to control air conditioning is the most costly alternative, but also provides the highest demand impact.

Figure 8-3: Illustration of the Build-Up Nature of the Time Based Residential Rates



[32] Manual control means that the utility has no ability to control the thermostat, so any changes to the thermostat must be made by the homeowner by manually changing the temperature setting. Therefore, a manual control rate program requires voluntary response to price signals.

TOU and CPP impacts are estimated based on a macro-analysis performed by the Brattle Group, examining measured load impacts for several utilities throughout the country.[33] The industrial interruptible rate is simply an assumption that the retail consumer can somehow curtail 1 MW of load during interruption notices. These curtailments could be garnered through shutting down processes or moving shifts or by other means.

Distributed Generation: It is assumed that a commercial application would equal 350 kW and an industrial application would equal 1,000 kW.

Commercial Lighting Control: Load impacts for commercial lighting were estimated using commercial load profiles developed by GDS for other energy efficiency and demand response analyses. The load profiles include estimated internal lighting wattage per square foot for various building types. A report by Peter Morante of the Lighting Research Center indicates that control switches can be installed in buildings to interrupt 25% of the lighting load (*e.g.* dimming some areas, or shutting off every third hallway light).[34] The commercial lighting program was broken into small and large commercial applications, and the average load impact for each group was used for the benefit/cost analysis. It is assumed that the control strategy would mirror the standard capacity water heater program, resulting in 100 hours of control each year. The commercial energy lighting results in energy losses as indicated in the Table 8.4 below.

Table 8-4: Commercial Lighting Control Load Impacts

Type	*Square Footage*	*Watts per Sq. Ft.*	*Total Watts*	*25% kW Reduction*
SMALL COMMERCIAL				
Office	*6,600*	*1.33*	*8,778*	*2.19*
Retail Store	*6,400*	*0.87*	*5,568*	*1.39*
Restaurant	*5,250*	*0.92*	*4,830*	*1.21*
School	*16,000*	*0.88*	*14,080*	*3.52*
Group Average	*8,563*	*0.97*	*8,306*	*2.08*
LARGE COMMERCIAL				
Office	*90,000*	*0.87*	*78,300*	*19.58*
Retail Store	*79,000*	*0.87*	*68,730*	*17.18*
Hospital	*155,800*	*0.64*	*99,712*	*24.93*
Group Average	*108,267*	*0.76*	*82,247*	*20.56*

Energy Management Systems: Energy Management Systems ("EMS") can take on many forms, but the basic approach is that multiple end-uses are controlled on-site through an integrated system to achieve combined demand reductions. Typically, these systems include built-in logic to monitor loads and initiate control measures when needed. Extensive research indicates that such systems are very site-specific, thus, characterizing a "general" EMS set-up is difficult. However, a pilot study of small commercial applications was conducted by Southern California Edison in 2006[35] using a product developed and sold by Dencor, Inc.

[33] *Rethinking Prices.* Faruqui, Ahmad, Ryan Hledik, and Sanem Sergici. *Public Utilities Fortnightly.* January 2010. Pp. 30-39, http://www.fortnightly.com/fortnightly/2010/01/rethinking-prices?page=0%2C0.

[34] "Making Lighting Responsive to Demand Response." Peter Morante, Lighting Research Center. Rensselaer Polytechnic Institute, http://www.ieadsm.org/Files/Tasks/Task%2013%20-%20Demand%20Response%20Resources/Peak%20Load%20Management%20Alliance%20-%20May%202005/Peter%20MoranteLRC.pdf

[35] "Demand Response Enabling Technologies For Small-Medium Businesses." Lockheed Martin Aspen, April 12, 2006.

(www.dencor.com). The system included control of rooftop air conditioners, walk-in coolers, walk-in freezers, reach-in coolers, ice makers, and electric water heaters. The pilot included retail stores, restaurants, beverage stores, offices, and small groceries, with loads ranging from 15 kW to 150 kW. The Dencor systems include the ability of the utility to monitor the system through the internet, dial-up, or GPS technology. The pilot program demonstrated an average 11.9 kW reduction for a customer with an average base load of 54.3 kW, a 22% reduction.

Both small commercial and larger industrial EMS were included in the benefit/cost analysis. For small commercial, this study uses the 11.9 kW impact from the Southern California Edison pilot study and assumed the same control strategy as a large capacity water heater program. With the significant upfront costs associated with an EMS, a customer is very likely willing to control for many more hours per year than a standard residential air conditioner or water heater strategy. For industrial applications, it is assumed the load is 1,000 kW and that 15% demand reductions can be achieved. Energy is assumed to be shifted and not lost due to control through the EMS.

Benefits

The benefits of avoided peaking demand and transmission demand are consistent with the energy efficiency analysis. Development of the avoided costs is detailed in Section 5.9 of the report. Avoided production demand is based on market price of capacity and growing into the value of a peaking unit. There is no benefit assumed for avoided transmission or distribution demand. For peak shifting programs, there is an avoided energy benefit associated with serving the load during the recovery periods that tend to have lower energy production costs. The benefit is the difference between the energy cost during peaking and recovery hours. For this study, the on- and off-peak avoided energy costs are used to estimate the benefit of shifting energy. For peak clipping programs in which energy is not recovered, the avoided energy cost is the on-peak energy charge.

Costs

The costs included in the Total Resource Cost Test benefit/cost analysis generally include equipment installation and carrying costs, program administration and marketing costs, and costs associated with delivery of the communication or price signal to the affected device or consumer. For direct control programs in which the participant incurs no cost, incentives are also included as program costs. Costs may be incurred by the G&T, Member Cooperative, or retail consumer. The TRC test does not include lost electric revenues that may arise from programs that reduce energy consumption.

Incentives

Incentives for demand response programs take on many forms and levels. For instance, some cooperatives are able to get participation for a water heater control program with little or no incentive, simply by appealing to the "cooperative spirit". Incentives include a one-time payment, monthly fixed payments, rate incentives, and contributions to equipment cost. For programs in which the participant has some share in equipment cost, incentives by the utility to offset that cost are excluded from the TRC test. However, in a program such as air conditioner control in which the participant has no monetary cost, incentives paid by the utility to the participant are included as a representation of the economic value the customer places on their potential displacement of comfort during control events. The levels of incentive assumed in the Big Rivers screening analysis are shown in Table 8-5 below. Some are assumed to be monthly payments (e.g., $4 per month for water heaters) and others, such as distributed generation, are rate incentives ($6.50 per kW-month demand credit). However, the ultimate form of the incentive is not as important as the magnitude for purposes of a screening analysis.

http://sites.energetics.com/madri/pdfs/LMADRT_060506.pdf

Table 8-5: Incentive Amounts for TRC Test

	Program	TRC Annual Incentive	Nature
Residential	Air Conditioner - 33% Cycling	$36	Recurring
	Air Conditioner - 50% Cycling	$48	Recurring
	Water Heater - 40/50 Gallon	$48	Recurring
	Smart Thermostat	$0	
	Time-of-Use (TOU) Rate	$0	
	Crticial Peak Pricing (CPP) Rate	$0	
Commercial	Distributed Generation	$0	
	Lighting - Small Application	$500	One-Time
	Lighting - Large Application	$1,000	One-Time
	Energy Management System (EMS)	$0	
	Time-of-Use (TOU) Rate	$0	
	Crticial Peak Pricing (CPP) Rate	$0	
Industrial	Distributed Generation	$0	
	Energy Management System (EMS)	$0	
	Interruptible Rate	$31,455	Recurring

CARRYING COSTS FOR CAPITAL EQUIPMENT

Two different carrying cost factors are used to expense capital items in the analysis. The first factor is when the utility will own and operate the equipment (direct control programs) and includes interest, depreciation at 10 years, operations and maintenance, and margins on the interest expense. Margins are a blended average of a G&T Times Interest Earned Ratio ("TIER") of 1.1 (25% weight) and a distribution cooperative TIER of 1.5 (75% weight). The second factor is when a commercial account owns the equipment. That factor includes interest, depreciation over 15 years, and operations and maintenance.

Table 8-6: Carrying Cost Factors

Item	Utility Ownership	Commercial Ownership
Interest	4.50%	5.50%
Depreciation	10.00%	6.67%
O&M	3.00%	3.00%
Insurance & Taxes	0.00%	0.00%
Margins on Interest	1.80%	0.00%
Total Carrying Cost	19.30%	15.17%

CAPITAL COSTS OF EQUIPMENT

Capital costs for DR equipment were based on current costs for residential control switches and on the assumed capital costs from Big Rivers' 2010 DSM Potential Study but escalated at 2.5% per year for four years to reflect current costs.

ADMINISTRATIVE, MARKETING, AND OPERATING COSTS

Other program costs were estimated using current estimates for central communication equipment and software and for G&T and Member Cooperative staffs to dedicate to the DR programs. Finally, marketing costs for each Member Cooperative were included. These costs were then levelized and divided into a number of DR participants that represents achieving 5% of rural peak demand reduction after 10 years of a program. The average program costs per DR program participant per year $17.29.

8.9 Conclusions and Recommendations for Demand Response

With Big Rivers and the region in and around MISO being long on capacity, the value of demand response programs is presently low, even lower than in the 2010 DSM Potential Study. Furthermore, there are no benefits associated with avoided transmission facilities either. Therefore, it is not surprising that most of the DR programs analyzed do not pass the TRC test. The following programs did pass the TRC test.

Commercial Lighting Control Large Application: This program passes the TRC test, but only by a very small margin. The benefit cost ratio is 1.02. These programs require intrusive installation such as wiring to individual fixtures throughout a building so that fixtures can be controlled by the utility. This would not be an ideal first program for DR, but may be considered and pursued by a utility with a mature DR portfolio and extensive experience in installation of control switches.

Interruptible Rate: This program is highly beneficial with very little cost. That is because the assumption is that the industrial customer is able to curtail 1 MW without additional equipment. An interruptible program looks highly beneficial in many DR studies even with low avoided cost benefits. Obviously, the challenge to the utility is finding candidates that meet these stringent criteria that would be willing to either change shifts or operations in order to reduce their power bills.

Recommendation

At this time, based on the study conclusions Big Rivers has elected to not pursue a formal demand response program. Most of the typical DR programs analyzed in this screening are not cost-effective at this time and those that are cost effective are either complicated to implement or are only marginally cost effective. Big Rivers would be better served by using its DSM budgets pursuing higher value energy efficiency programs. However, as capacity tightens in the region, the value of capacity should increase, approaching the avoided cost of a peaking unit. At that time, demand response programs could become cost effective. Big Rivers should therefore continue to monitor the cost effectiveness of DR. Based on GDS recommendations in this study, Big Rivers will:

- Not pursue a full scale demand response program at this time.
- Continue to monitor opportunities for demand response, looking for reduction in costs or increases in the value of avoided peaking generation.
- Monitor the opportunity of new technologies that may provide peak demand reduction benefits, including Smart Grid technologies.
- Encourage the Member Cooperatives to consider whether any existing large commercial or industrial accounts would be benefitted by an interruptible rate arrangement. If so, determine whether there is a desire on the part of the Members to offer an interruptible rate arrangement.

9 ENERGY EFFICIENCY PROGRAMS AND PROGRAM POTENTIAL SUMMARY

Based on the results of the achievable potential analysis, Big Rivers will continue to offer the current portfolio of energy efficiency programs, which very closely track the programs described below, to its Member Cooperatives, while continuing to evaluate new cost effective programs.

RESIDENTIAL PROGRAMS

1) Residential Lighting Program
2) Residential Efficient Appliances Program
3) Residential HVAC Program
4) Residential Weatherization Program
5) Residential New Construction Program
6) Residential HVAC Tune-Up Program

COMMERCIAL/INDUSTRIAL ENERGY EFFICIENCY PROGRAMS

7) C&I Lighting Program
8) C&I HVAC Program
9) C&I General Program

These programs represent the end-uses and equipment that held significant opportunities for cost-effective savings in the residential and commercial/industrial sector and align with current Big Rivers DSM offerings. GDS has provided an overview of existing energy efficiency programs, the target market, eligible energy efficiency measures, and proposed financial incentives for participants.

GDS has also provided the potential savings, benefits, and costs for these programs assuming two funding scenarios (that for the purpose of this study appreciate over time. The scenarios are incentive budgets of $1 million in 2014, and $2 million in 2014. Estimated budgets in future years are a function of the estimated incremental annual achievable potential savings in future years. Actual energy and demand savings and program costs will depend upon many factors, including actual program funding levels and member participation in the DSM programs offered by Big Rivers.

It is important to note that the potential savings, benefits, and costs presented in this chapter are a subset of the achievable potential. The objective of the calculation of program potential is to estimate what could be achieved given specific funding levels, specifically those shown in Tables 9-1 and 9-2 below. These summaries are not intended to represent specific future program designs, and are not based on actual or approved program budgets in future years.

Table 9-1 shows the estimated annual budgets for the $1 million incentive scenario for the residential and commercial/industrial sector. The allocation of incentive spending across sectors assumes that approximately two-thirds of the spending will be allocated towards the residential sector, with the balance going to the C&I sector. This assumption aligns with actual Big Rivers DSM results in recent years. Table 9-2 shows the estimated annual budgets for the $2 million incentive scenario for the residential and commercial/industrial sector.

Table 9-1: $1 million scenario – Annual Incentive Budgets by Sector

	Residential	Commercial / Industial	Total
2014	$666,667	$329,403	$996,069
2015	$699,845	$337,791	$1,037,636
2016	$719,760	$347,284	$1,067,044
2017	$737,355	$355,473	$1,092,829
2018	$754,102	$363,744	$1,117,846
2019	$776,231	$371,715	$1,147,947
2020	$799,398	$380,469	$1,179,867
2021	$822,972	$389,271	$1,212,243
2022	$839,780	$398,153	$1,237,933
2023	$859,139	$407,910	$1,267,049
2014-2023	$7,675,248	$3,681,214	$11,356,462

Table 9-2: $2 million scenario – Annual Incentive Budgets by Sector

	Residential	Commercial / Industial	Total
2014	$1,333,333	$661,024	$1,994,357
2015	$1,399,690	$675,764	$2,075,455
2016	$1,439,520	$694,529	$2,134,048
2017	$1,474,710	$711,178	$2,185,889
2018	$1,508,203	$727,645	$2,235,848
2019	$1,552,463	$744,695	$2,297,158
2020	$1,598,796	$762,874	$2,361,670
2021	$1,645,944	$780,710	$2,426,654
2022	$1,679,559	$801,165	$2,480,724
2023	$1,718,278	$820,773	$2,539,051
2014-2023	$15,350,496	$7,380,357	$22,730,853

9.1 Residential Energy Efficiency Program Potential Scenarios

This section of the report provides an overview of the residential energy efficiency program potential for Big Rivers over the next 10 years. GDS has provided a description of the existing program designs and recommendations for measures to include in residential programs on a prospective basis.

9.1.1 Residential Lighting Program

Big Rivers offers a residential lighting replacement program to its Members. This program promotes distribution of CFL bulbs by providing reimbursement to Members who purchase CFL bulbs. GDS recommends that the Residential Lighting Program continue to offer rebates for CFLs and also begin to offer rebates for LED bulbs. LED bulbs are increasing in cost-effectiveness due to rapidly dropping retail prices and are expected to gain an increased market share in the next several years. Table 9-3 shows the measures included in the residential lighting program for this study. Measure details are provided in Appendix A.

Table 9-3: Residential Lighting Program Measures

Residential Lighting Program
Standard CFL
Specialty CFL
Standard LED
Specialty LED

Table 9-4 and Table 9-5 show the estimated impacts of the Residential Lighting Program in the $1 million and $2 million incentive scenarios. The tables provide the estimated impacts in the first year (2014) as well as the total impacts across a 10-yr period. The $100,000 incentive budget in 2014 for the $1 million scenario aligns with current Big Rivers budget estimates for the program. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost.[36] The administrative budget assumes that administrative costs will equal 20% of incremental measure cost.

Table 9-4: Residential Lighting Program – $1 million scenario[37]

Residential Lighting Program	2014	2014-2023 Totals
Total Budget	$157,143	$945,802
Incentive Budget	$100,000	$601,874
Admin Budget	$57,143	$343,928
Cumulative Annual Participants	14,682	140,644
Total Annual kWh	526,152	3,107,649
Winter Peak kW	171	987
Summer Peak kW	63	364

Table 9-5: Residential Lighting Program – $2 million scenario

Residential Lighting Program	2014	2014-2023 Totals
Total Budget	$314,286	$1,891,603
Incentive Budget	$200,000	$1,203,748
Admin Budget	$114,286	$687,856
Cumulative Annual Participants	29,363	281,288
Total Annual kWh	1,052,305	6,215,298
Winter Peak kW	342	1,974
Summer Peak kW	126	729

9.1.2 Residential Efficient Appliances Program

Big Rivers offers multiple residential efficient appliances programs to its Members. The programs promote installation of efficient clothes washers and refrigerators and the removal and recycling of older inefficient refrigerators. The study combined efficient clothes washers, efficient refrigerators and refrigerator recycling measures into a consolidated Residential Efficient Appliances program. Table 9-6 shows the measures included in the residential efficient appliances program for this study. Measure details are provided in Appendix A.

[36] The residential lighting program potential scenario assumes a 35% incentive (instead of 100% incentives) because the measure mix is largely comprised of LED bulbs, which are more expensive than CFL bulbs. The residential weatherization program potential scenario assumes that CFL bulbs will continue to be distributed during site visits at no cost to Members.

[37] It is important to note that the results for the Residential Lighting Program are tied to the results of the Residential Weatherization program. GDS assumed that a portion of the market for efficient lighting installations is addressed through the weatherization package measure. GDS made this assumption to align with current Big Rivers DSM program practices. The estimates in Tables 9-4 and 9-5 assume approximately two-thirds of the bulbs are LED bulbs and the balance is CFL bulbs.

Table 9-6: Residential Efficient Appliances Program Measures

Residential Efficient Appliances
ENERGY STAR Refrigerators
Refrigerator Recyclying
ENERGY STAR Clothes Washer

Table 9-7 and Table 9-8 show the estimated impacts of the Residential Efficient Appliances Program in the \$1 million and \$2 million incentive scenarios. The tables provide the estimated impacts in the first year (2014) as well as the total impacts across a 10-yr period. The \$150,000 incentive budget in 2014 for the \$1 million scenario aligns with current Big Rivers budget estimates for the program. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost. The administrative budget assumes that administrative costs will equal 20% of incremental measure cost.

Table 9-7: Residential Efficient Appliances Program – \$1 million scenario

Residential Efficient Appliances	2014	2014-2023 Totals
Total Budget	\$207,988	\$2,093,138
Incentive Budget	\$150,000	\$1,508,437
Admin Budget	\$57,988	\$584,700
Cumulative Annual Participants	2,030	11,983
Total Annual kWh	775,025	6,475,637
Winter Peak kW	120	1,055
Summer Peak kW	147	1,293

Table 9-8: Residential Efficient Appliances Program – \$2 million scenario

Residential Efficient Appliances	2014	2014-2023 Totals
Total Budget	\$415,976	\$4,186,275
Incentive Budget	\$300,000	\$3,016,874
Admin Budget	\$115,976	\$1,169,401
Cumulative Annual Participants	4,060	23,966
Total Annual kWh	1,550,050	12,951,274
Winter Peak kW	239	2,111
Summer Peak kW	294	2,587

9.1.3 Residential HVAC Program

Big Rivers offers a residential HVAC replacement program to its Members. This program promotes increased use of high efficiency HVAC systems among the retail members of the Member Cooperatives by providing reimbursement to Member Cooperatives members for upgrading their HVAC systems. Table 9-9 shows the measures included in the residential HVAC program for this study. Measure details are provided in Appendix A.

Table 9-9: Residential HVAC Program Measures

Residential HVAC Program
Heat Pump - Replacing Electric Furnace
Dual Fuel Heat Pump - in place of ASHP
Dual Fuel Heat Pump - Replacing Electric Furnace
Programmable/Smart Thermostat - Gas Heated Homes
Programmable/Smart Thermostat - Electric (ASHP)
Programmable/Smart Thermostat - Electric (Furnace)

Table 9-10 and Table 9-11 show the estimated impacts of the Residential HVAC Program in the $1 million and $2 million incentive scenarios. The tables provide the estimated impacts in the first year (2014) as well as the total impacts across a 10-yr period. The $90,000 budget in 2014 for the $1 million scenario aligns with current Big Rivers budget estimates for the program. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost. The administrative budget assumes that administrative costs will equal 20% of incremental measure cost.

Table 9-10: Residential HVAC Program – $1 million scenario

Residential HVAC Program	2014	2014-2023 Totals
Total Budget	$141,429	$3,522,547
Incentive Budget	$90,000	$2,241,621
Admin Budget	$51,429	$1,280,926
Cumulative Annual Participants	733	2,242
Total Annual kWh	505,715	10,794,150
Winter Peak kW	50	1,070
Summer Peak kW	8	222

Table 9-11: Residential HVAC Program – $2 million scenario

Residential HVAC Program	2014	2014-2023 Totals
Total Budget	$282,857	$7,045,094
Incentive Budget	$180,000	$4,483,242
Admin Budget	$102,857	$2,561,852
Cumulative Annual Participants	1,465	4,485
Total Annual kWh	1,011,430	21,588,299
Winter Peak kW	101	2,139
Summer Peak kW	15	444

9.1.4 Residential Weatherization Program

Big Rivers offers a residential weatherization program to its Members. This program promotes the implementation of weatherization measures among the retail members of the Member Cooperatives by providing weatherization improvements to their homes. Table 9-12 shows the measures included in the residential weatherization program for this study. Stand-alone ceiling insulation and floor insulation measures are included in addition to the weatherization package measure to account for the fact that homes could realize substantial savings from insulation. The study assumes that the cost of the stand-alone measures would be shared by Big Rivers and the participant, whereas the weatherization package measure would be paid for 100% by Big Rivers. Measure details are provided in Appendix A.

Table 9-12: Residential Weatherization Program Measures[38]

Residential Weatherization Program
Ceiling Insulation - Gas Heated Home
Weatherization Package - Gas Heated Home
Ceiling Insulation - Electric Heated (ASHP) Home
Floor Insulation - Electric Heated (ASHP) Home
Weatherization Package - Electric Heated (ASHP) Home
Ceiling Insulation - Electric Heated (Furnace) Home
Floor Insulation - Electric Heated (Furnace) Home
Weatherization Package - Electric Heated (Furnace) Home

Table 9-13 and Table 9-14 show the estimated impacts of the Residential Weatherization Program in the $1 million and $2 million incentive scenarios. The tables provide the estimated impacts in the first year (2014) as well as the total impacts across a 10-yr period. The budget of approximately $206,000 in 2014 for the $1 million scenario is approximately aligned with current Big Rivers budget estimates for the program ($250,000), but was capped at $206,000 in order to not exceed the residential incentive allowance of two-thirds of $1,000,000 in the $1 million scenario. GDS elected to cap the Residential Weatherization program budget instead of another program because savings that result from the Residential Weatherization program have the highest acquisition cost in terms of the money Big Rivers spends to save a kWh relative to the other residential programs. The high acquisition cost for this program is due the provision that Big Rivers pays for 100% of the incremental measure cost for the full weatherization package measure and also because the weatherization measures are more expensive than most of the other measures included in the Big Rivers residential energy efficiency portfolio.

The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost for the stand-alone insulation measures and 100% of the incremental cost for the full weatherization package measures. The administrative budget assumes that administrative costs will equal 20% of incremental measure cost.

Table 9-13: Residential Weatherization Program – $1 million scenario[39]

Residential Weatherization Program	2014	2014-2023 Totals
Total Budget	$257,417	$2,566,907
Incentive Budget	$205,667	$2,050,618
Admin Budget	$51,750	$516,289
Cumulative Annual Participants	86	864
Total Annual kWh	246,696	2,215,470
Winter Peak kW	80	667
Summer Peak kW	73	468

[38]The weatherization package measures include insulation, air/duct sealing, CFL bulbs, and low flow devices.
[39] It is important to note that the results for the Residential Lighting Program are tied to the results of the Residential Weatherization program. GDS assumed that a portion of the market for efficient lighting installations is addressed through the weatherization package measure. GDS made this assumption to align with current Big Rivers DSM program practices.

Table 9-14: Residential Weatherization Program – $2 million scenario

Residential Weatherization Program	2014	2014-2023 Totals
Total Budget	$514,833	$5,133,815
Incentive Budget	$411,333	$4,101,237
Admin Budget	$103,500	$1,032,578
Cumulative Annual Participants	173	1,728
Total Annual kWh	493,392	4,430,941
Winter Peak kW	161	1,334
Summer Peak kW	146	936

9.1.5 Residential New Construction Program

Big Rivers offers a residential new construction replacement program to its Members. This program provides incentives to home owners and builders to use energy efficient building standards as outlined in the Touchstone Energy® certification program. Table 9-15 shows the measures included in the residential new construction program for this study. Measure details are provided in Appendix A.

Table 9-15: Residential New Construction Program Measures

Residential New Construction
Touchstone Home - Gas Heated
Touchstone Home - Electric Heated

Table 9-16 and Table 9-17 show the estimated impacts of the Residential New Construction Program in the $1 million and $2 million incentive scenarios. The tables provide the estimated impacts in the first year (2014) as well as the total impacts across a 10-yr period. The $100,000 budget in 2014 for the $1 million scenario aligns with current Big Rivers budget estimates for the program. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost. The administrative budget assumes that administrative costs will equal 20% of incremental measure cost.

Table 9-16: Residential New Construction Program – $1 million scenario

Residential New Construction	2014	2014-2023 Totals
Total Budget	$157,143	$1,629,731
Incentive Budget	$100,000	$1,037,102
Admin Budget	$57,143	$592,630
Cumulative Annual Participants	80	829
Total Annual kWh	204,233	2,120,243
Winter Peak kW	38	391
Summer Peak kW	28	291

Table 9-17: Residential New Construction Program – $2 million scenario

Residential New Construction	2014	2014-2023 Totals
Total Budget	$314,286	$3,259,463
Incentive Budget	$200,000	$2,074,204
Admin Budget	$114,286	$1,185,259
Cumulative Annual Participants	160	1,658
Total Annual kWh	408,466	4,240,486
Winter Peak kW	75	782
Summer Peak kW	56	583

9.1.6 Residential HVAC Tune-Up Program

Big Rivers offers a residential HVAC tune-up replacement program to its Members. This program promotes the initiation of annual maintenance on heating and air conditioning equipment among the retail members of the Member Cooperatives by providing reimbursement to Member Cooperative retail members that have their heating and cooling systems professionally cleaned and serviced. Table 9-18 shows the measures included in the residential HVAC tune-up program for this study. Measure details are provided in Appendix A.

Table 9-18: Residential HVAC Tune-Up Program Measures

Residential HVAC Tune-Up Program
HVAC Tune-up

Table 9-19 and Table 9-20 show the estimated impacts of the Residential HVAC Tune-up Program in the $1 million and $2 million incentive scenarios. The tables provide the estimated impacts in the first year (2014) as well as the total impacts across a 10-yr period. The $21,000 budget in 2014 for the $1 million scenario aligns with current Big Rivers budget estimates for the program. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost. The administrative budget assumes that administrative costs will equal 20% of incremental measure cost.

Table 9-19: Residential HVAC Tune-Up – $1 million scenario

Residential HVAC Tune-up Program	2014	2014-2023 Totals
Total Budget	$33,000	$370,223
Incentive Budget	$21,000	$235,596
Admin Budget	$12,000	$134,626
Cumulative Annual Participants	375	2,180
Total Annual kWh	177,359	1,030,913
Winter Peak kW	55	320
Summer Peak kW	70	405

Table 9-20: Residential HVAC Tune-Up – $2 million scenario

Residential HVAC Tune-up Program	2014	2014-2023 Totals
Total Budget	$66,000	$740,446
Incentive Budget	$42,000	$471,193
Admin Budget	$24,000	$269,253
Cumulative Annual Participants	750	4,359
Total Annual kWh	354,718	2,061,827
Winter Peak kW	110	640
Summer Peak kW	139	809

9.2 Commercial and Industrial Energy Efficiency Program Potential Scenarios

This section of the report provides an overview of the C&I energy efficiency program potential for Big Rivers over the next 10 years. The study provides a description of the existing program designs and recommendations for enhancements and modifications to program design for Big Rivers to consider prospectively.

9.2.1 Commercial and Industrial Prescriptive Lighting Program

Big Rivers offers two prescriptive lighting replacement programs to its Members: a high efficiency lighting replacement incentive program and a high efficiency outdoor lighting program[40]. These programs provide an incentive to commercial and industrial retail member consumers for whom service is taken under Big Rivers' Rural Delivery Service ("RDS") tariff to upgrade poorly designed and low efficiency lighting systems. The measures included in the Prescriptive Lighting program for this study are the same as those listed in Table 7-9. Measure details are provided in Appendix B.

Table 9-21 and Table 9-22 show the estimated impacts of the Commercial and Industrial Prescriptive Lighting Program in the $1 million and $2 million incentive scenarios. The tables provide the estimated impacts in the first year (2014) as well as the total impacts across a 10-yr period. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost. The administrative budget assumes that administrative costs will equal 20% of the budget.

Table 9-21: Commercial and Industrial Prescriptive Lighting Program – $1 million scenario

C&I Prescriptive Lighting Program	2014	2014-2023 Totals
Total Budget	$256,108	$2,867,665
Incentive Budget	$204,886	$2,294,132
Admin Budget	$51,222	$573,533
Cumulative Annual Participants	3,803	41,268
Total Annual kWh	1,564,051	2,699,129
Winter Peak kW	133	252
Summer Peak kW	211	399

[40] The outdoor lighting program is only offered to the member cooperatives and not the retail commercial customer.

Table 9-22: Commercial and Industrial Prescriptive Lighting Program – $2 million scenario

C&I Prescriptive Lighting Program	2014	2014-2023 Totals
Total Budget	$512,546	$5,735,928
Incentive Budget	$410,037	$4,588,742
Admin Budget	$102,509	$1,147,186
Cumulative Annual Participants	7,606	82,537
Total Annual kWh	3,127,344	5,396,238
Winter Peak kW	267	504
Summer Peak kW	422	797

9.2.2 Commercial and Industrial Prescriptive HVAC Program

Big Rivers offers a prescriptive HVAC program to its commercial and industrial Members for whom service is taken under Big Rivers' RDS tariff. This program provides an incentive to commercial and industrial retail member consumers to upgrade inefficient HVAC equipment and to maintain and tune-up their existing equipment. The measures included in the Prescriptive HVAC program for this study are the same as those listed in Table 7-9[41]. Measure details are provided in Appendix B.

Table 9-23 and Table 9-24 show the estimated impacts of the Commercial and Industrial Prescriptive HVAC Program in the $1 million and $2 million incentive scenarios. The tables provide the estimated impacts in the first year (2014) as well as the total impacts across a 10-yr period. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost. The administrative budget assumes that administrative costs will equal 20% of the budget.

Table 9-23: Commercial and Industrial Prescriptive HVAC Program – $1 million scenario

C&I Prescriptive HVAC Program	2014	2014-2023 Totals
Total Budget	$71,998	$787,267
Incentive Budget	$57,599	$629,814
Admin Budget	$14,400	$157,453
Cumulative Annual Participants	436	4,739
Total Annual kWh	457,813	521,167
Winter Peak kW	30	32
Summer Peak kW	179	207

Table 9-24: Commercial and Industrial Prescriptive HVAC Program – $2 million scenario

C&I Prescriptive HVAC Program	2014	2014-2023 Totals
Total Budget	$145,136	$1,571,227
Incentive Budget	$116,109	$1,256,981
Admin Budget	$29,027	$314,245
Cumulative Annual Participants	873	9,460
Total Annual kWh	906,647	1,064,526
Winter Peak kW	58	67
Summer Peak kW	357	421

[41] The measures in the Space Heating, Space Cooling and Ventilation end-uses comprise the measures included in the Prescriptive HVAC program for this study.

9.2.3 Commercial and Industrial General Program

Big Rivers offers a general efficiency program to its Members for whom service is taken under Big Rivers' RDS tariff. This program provides an incentive to commercial and industrial retail members to upgrade all aspects of cost-effective energy efficiency achievable in individual facilities. The measures included in the general program for this study are the same as those listed in Table 7-9[42]. Measure details are provided in Appendix B.

Table 9-25 and Table 9-26 show the estimated impacts of the Commercial and Industrial Prescriptive Lighting Program in the $1 million and $2 million incentive scenarios. The tables provide the estimated impacts in the first year (2014) as well as the total impacts across a 10-yr period. The incentive budget assumes that Big Rivers will pay an incentive equal to 35% of the incremental measure cost. The administrative budget assumes that administrative costs will equal 20% of the budget.

Table 9-25: Commercial and Industrial General Program – $1 million scenario

C&I General Program	2014	2014-2023 Totals
Total Budget	$83,648	$946,585
Incentive Budget	$66,918	$757,268
Admin Budget	$16,730	$189,317
Cumulative Annual Participants	621	6,722
Total Annual kWh	564,572	904,274
Winter Peak kW	70	99
Summer Peak kW	82	133

Table 9-26: Commercial and Industrial General Program – $2 million scenario

C&I General Program	2014	2014-2023 Totals
Total Budget	$168,598	$1,918,292
Incentive Budget	$134,878	$1,534,633
Admin Budget	$33,720	$383,658
Cumulative Annual Participants	1,245	13,491
Total Annual kWh	1,142,071	1,898,426
Winter Peak kW	139	198
Summer Peak kW	168	289

9.3 Program Potential Summary

Table 9-27 and Table 9-28 presents summarized information regarding the annual participation, energy savings, demand savings, and Big Rivers budgets for the residential and C&I energy efficiency programs. The $1 million incentive budget scenario is presented in Table 9-27. The $2 million incentive budget scenario is presented in Table 9-28.

In the $1 mill scenario, the programs result in about 53,686 MWh of cumulative annual energy savings in 2023. The programs are also estimated to achieve winter peak demand savings of 7.0 MW. In the $2 mill scenario, the programs result in about 107,578 MWh of cumulative annual energy savings in 2023. The programs are also estimated to achieve winter peak demand savings of 14 MW.

[42] The General program measures include all measures not included in the Lighting, Space Heating, Space Cooling or Ventilation end-uses.

Table 9-27: Program Portfolio Detail: Annual Participation, Savings, and Budget by Program, $1 mill incentive scenario

ALL RESIDENTIAL PROGRAMS COMBINED	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Incremental Annual Participants	17,986	18,799	19,106	19,165	19,122	19,079	19,127	19,147	19,072	19,016
Cumulative Annual Participants	17,986	35,298	52,733	70,090	87,268	101,934	116,509	131,054	144,909	158,743
Cumulative Annual MWh Savings	2,435	5,086	7,892	10,847	13,930	16,865	19,870	21,080	23,380	25,744
Cumulative Annual Winter MW Savings	0.51	1.06	1.62	2.19	2.77	3.28	3.81	3.68	4.08	4.49
Cumulative Annual Summer MW Savings	0.39	0.79	1.20	1.61	2.03	2.37	2.71	2.64	2.84	3.04
Incentives	$666,667	$699,845	$719,760	$737,355	$754,102	$776,231	$799,398	$822,972	$839,780	$859,139
Administrative	$287,452	$306,411	$317,791	$327,845	$337,415	$350,061	$363,298	$376,769	$387,497	$398,560
Total Big Rivers	***$954,119***	***$1,006,256***	***$1,037,551***	***$1,065,201***	***$1,091,517***	***$1,126,292***	***$1,162,696***	***$1,199,741***	***$1,227,277***	***$1,257,699***
ALL C&I PROGRAMS COMBINED	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Incremental Annual Participants	4,860	4,994	5,136	5,886	6,193	6,400	7,052	7,464	7,682	8,275
Cumulative Annual Participants	4,860	9,831	14,921	20,075	25,330	30,683	36,112	41,539	47,088	52,729
Cumulative Annual MWh Savings	2,586	5,225	7,931	10,671	13,459	16,293	19,163	22,032	24,963	27,942
Cumulative Annual Winter MW Savings	0.23	0.47	0.72	0.96	1.21	1.47	1.73	1.98	2.25	2.51
Cumulative Annual Summer MW Savings	0.47	0.95	1.45	1.95	2.46	2.98	3.51	4.04	4.57	5.12
Incentives	$329,403	$337,791	$347,284	$355,473	$363,744	$371,715	$380,469	$389,271	$398,153	$407,910
Administrative	$82,351	$84,448	$86,821	$88,868	$90,936	$92,929	$95,117	$97,318	$99,538	$101,978
Total Big Rivers	***$411,754***	***$422,238***	***$434,105***	***$444,342***	***$454,680***	***$464,644***	***$475,587***	***$486,588***	***$497,691***	***$509,888***
ALL PROGRAMS COMBINED	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Cumulative Annual MWh Savings	5,022	10,311	15,823	21,518	27,389	33,158	39,034	43,111	48,343	53,686
Cumulative Annual Winter MW Savings	0.75	1.53	2.33	3.15	3.98	4.75	5.54	5.67	6.33	7.00
Cumulative Annual Summer MW Savings	0.86	1.75	2.65	3.57	4.49	5.36	6.22	6.68	7.41	8.16
Incentives	$996,069	$1,037,636	$1,067,044	$1,092,829	$1,117,846	$1,147,947	$1,179,867	$1,212,243	$1,237,933	$1,267,049
Administrative	$369,803	$390,859	$404,612	$416,714	$428,351	$442,989	$458,416	$474,087	$487,035	$500,537
Total Big Rivers	***$1,365,872***	***$1,428,495***	***$1,471,656***	***$1,509,542***	***$1,546,197***	***$1,590,936***	***$1,638,283***	***$1,686,330***	***$1,724,968***	***$1,767,587***

Table 9-28: Program Portfolio Detail: Annual Participation, Savings, and Budget by Program, $2 mill incentive scenario

ALL RESIDENTIAL PROGRAMS COMBINED	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Incremental Annual Participants	35,972	37,598	38,212	38,330	38,244	38,157	38,254	38,294	38,144	38,031
Cumulative Annual Participants	35,972	70,595	105,467	140,180	174,537	203,869	233,018	262,107	289,818	317,485
Cumulative Annual MWh Savings	4,870	10,172	15,785	21,693	27,860	33,730	39,741	42,159	46,760	51,488
Cumulative Annual Winter MW Savings	1.03	2.12	3.23	4.37	5.53	6.57	7.62	7.37	8.17	8.98
Cumulative Annual Summer MW Savings	0.78	1.58	2.40	3.23	4.06	4.74	5.43	5.28	5.69	6.09
Incentives	$1,333,333	$1,399,690	$1,439,520	$1,474,710	$1,508,203	$1,552,463	$1,598,796	$1,645,944	$1,679,559	$1,718,278
Administrative	$574,904	$612,822	$635,582	$655,691	$674,830	$700,121	$726,597	$753,539	$774,994	$797,119
Total Big Rivers	***$1,908,237***	***$2,012,512***	***$2,075,101***	***$2,130,401***	***$2,183,033***	***$2,252,584***	***$2,325,392***	***$2,399,483***	***$2,454,554***	***$2,515,397***
ALL C&I PROGRAMS COMBINED	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Incremental Annual Participants	9,724	9,990	10,268	11,775	12,391	12,807	14,109	14,943	15,386	16,558
Cumulative Annual Participants	9,724	19,668	29,843	40,153	50,669	61,376	72,237	83,097	94,205	105,488
Cumulative Annual MWh Savings	5,176	10,456	15,878	21,366	26,954	32,641	38,406	44,171	50,078	56,090
Cumulative Annual Winter MW Savings	0.46	0.94	1.42	1.92	2.42	2.93	3.44	3.96	4.49	5.03
Cumulative Annual Summer MW Savings	0.95	1.91	2.91	3.91	4.93	5.97	7.03	8.09	9.17	10.27
Incentives	$661,024	$675,764	$694,529	$711,178	$727,645	$744,695	$762,874	$780,710	$801,165	$820,773
Administrative	$165,256	$168,941	$173,632	$177,795	$181,911	$186,174	$190,719	$195,178	$200,291	$205,193
Total Big Rivers	***$826,280***	***$844,706***	***$868,161***	***$888,973***	***$909,556***	***$930,869***	***$953,593***	***$975,888***	***$1,001,456***	***$1,025,966***
ALL PROGRAMS COMBINED	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Cumulative Annual MWh Savings	10,046	20,628	31,663	43,059	54,814	66,372	78,147	86,331	96,839	107,578
Cumulative Annual Winter MW Savings	1.49	3.05	4.66	6.29	7.95	9.49	11.06	11.33	12.66	14.01
Cumulative Annual Summer MW Savings	1.73	3.50	5.31	7.14	8.99	10.72	12.46	13.37	14.86	16.36
Incentives	$1,994,357	$2,075,455	$2,134,048	$2,185,889	$2,235,848	$2,297,158	$2,361,670	$2,426,654	$2,480,724	$2,539,051
Administrative	$740,160	$781,763	$809,214	$833,486	$856,741	$886,295	$917,315	$948,716	$975,285	$1,002,312
Total Big Rivers	***$2,734,518***	***$2,857,218***	***$2,943,262***	***$3,019,374***	***$3,092,589***	***$3,183,452***	***$3,278,985***	***$3,375,370***	***$3,456,009***	***$3,541,363***

10 Overall Conclusions and Summary

There is significant potential for electric energy efficiency and demand response savings in the Big Rivers Members' service territories by 2023. The estimated achievable potential electricity savings would amount to 368,891 MWh a year (an 11.2% reduction in projected 2023 MWh sales). Energy efficiency resources can also serve to reduce the overall winter peak demand over the same period by 65 MW, or 10.0% of the forecasted 2023 system peak. Achievable summer peak savings are 64 MW, or 9.5% of the total system peak in 2023.

Based on these estimated achievable potential results, a portfolio of DSM programs was designed for Big Rivers that could achieve significant energy and demand savings at a pre-determined level of spending. Two program potential scenarios were evaluated. The first is based on a funding target of $1 million in incentives in 2014. The second is based on a funding target of $2 million in incentives in 2014. Incentive spending in future years is a function of the estimated achievable potential. The results of two spending scenarios provide Big Rivers with two options to consider offering its Members on a prospective basis. GDS recommends that Big Rivers review the program level spending and savings for each incentive scenario, determine which level of incentive investment it plans to commit in the future, and then modify its DSM programs to align with the programs included in the program potential evaluation in this study

Table 10-1 and Table 10-2 provide an overall summary of the two funding scenarios. The total budget from 2014-2013 under the $1 million scenario is approximately $15.7 million. The total budget from 2014-2013 under the $2 million scenario is approximately $31.5 million.

Table 10-1: Program Potential $1 million scenario

	Cumulative Annual MWh Savings	Cumulative Annual Winter MW Savings	Total Budget (Incentives + Admin)	NPV Benefits $2014	NPV Costs $2014
Residential Programs					
Residential Lighting Program	307	0.1	$945,802	$4,724,857	$1,765,652
Residential Efficient Appliances Program	774	0.1	$2,093,138	$9,363,432	$2,901,384
Residential HVAC Program	1,508	0.2	$3,522,547	$9,445,738	$3,045,654
Residential Weatherization Program	222	0.1	$2,566,907	$5,447,379	$2,560,435
Residential New Construction Program	198	0.0	$1,629,731	$5,244,956	$2,949,590
Residential HVAC Tune-Up Program	206	0.1	$370,223	$3,832,610	$3,678,942
Commercial/Industrial Programs					
C/I Lighting Program	16,972	1.4	$2,867,665	$11,449,531	$5,311,884
C/I HVAC Program	4,917	0.3	$787,267	$4,392,042	$1,466,519
C/I General Program	6,054	0.8	$946,585	$3,070,415	$1,752,324
Totals	31,157	3.1	$15,729,866	$56,970,960	$25,432,384

Table 10-2: Program Potential $2 million scenario

	Cumulative Annual MWh Savings	Cumulative Annual Winter MW Savings	Total Budget (Incentives + Admin)	NPV Benefits $2014	NPV Costs $2014
Residential Programs					
Residential Lighting Program	615	0.2	$1,891,603	$9,449,714	$3,531,304
Residential Efficient Appliances Program	1,548	0.2	$4,186,275	$18,726,864	$5,802,768
Residential HVAC Program	3,015	0.3	$7,045,094	$18,891,476	$6,091,308
Residential Weatherization Program	443	0.1	$5,133,815	$10,894,757	$5,120,870
Residential New Construction Program	396	0.1	$3,259,463	$10,489,912	$5,899,180
Residential HVAC Tune-Up Program	412	0.1	$740,446	$7,665,220	$7,357,884
Commercial/Industrial Programs					
C/I Lighting Program	33,941	2.9	$5,735,928	$22,899,640	$10,625,014
C/I HVAC Program	9,817	0.6	$1,571,227	$8,764,337	$2,923,498
C/I General Program	12,333	1.5	$1,918,292	$6,330,864	$3,549,659
Totals	62,519	6.1	$31,482,141	$114,112,784	$50,901,486

The DSM potential estimates provided in this report are based upon the current load forecast as well as appliance saturation data, data on energy efficiency measure costs and savings, and measure lives available at the time of this study. Over time, additional and emerging technologies may serve to increase the potential for additional energy and demand savings and warrant additional attention at the program level.

Actual energy and demand savings will depend upon the level and degree of Big Rivers' system participation in the DSM programs offered by Big Rivers. The budget amounts and programs are subject to annual Big Rivers' Board review and approval. Therefore, while the figures presented in this report represent best current estimates of savings and costs, actual results will be different.

APPENDIX A: RESIDENTIAL MEASURE DETAIL

Big Rivers - Residential Measure Database

Measure ID	Measure Name	Home Type (DET/AT T/MF/MF SM/MF-MM)	ROB vs. Retrofit vs. ER vs. NC	Income Target (All / LI)	Base Elec. Use (kWh)	% Savings	Annual kWh Savings	Per Unit Winter NCP kW Savings	Per Unit Summer NCP kW Savings	Annual Non-elec. Savings (MMBTU)	Annual Water Savings (gal.)	Useful Life	Incremental /Full Cost	O&M Savings	Measure/End Use Description	Base Saturation	EE Saturation
1000	Appliances																
1001	Energy Star Compliant Top-Mount Refrigerator	SF	ROB	All	466.3	10.0%	46.6	0.06	0.06	0.00	0	17	$110.00	$0.00	Homes w/ Refrigerators	96.5%	77.2%
1002	Energy Star Compliant Side-by-Side Refrigerator	SF	ROB	All	550.4	10.0%	55.0	0.07	0.07	0.00	0	17	$110.00	$0.00	Homes w/ Refrigerators	96.5%	77.2%
1003	Energy Star Compliant Chest Freezer	SF	ROB	All	406.9	10.0%	40.7	0.01	0.01	0.00	0	12	$35.00	$0.00	Homes w/ Freezers	63.6%	54.9%
1004	Energy Star Compliant Upright Freezer (Manual Def.)	SF	ROB	All	422.9	10.0%	42.3	0.01	0.01	0.00	0	12	$35.00	$0.00	Homes w/ Freezers	63.6%	54.9%
1005	Energy Star Dehumidifer	SF	ROB	All	1,064.0	20.0%	213.0	0.05	0.05	0.00	0	12	$45.00	$0.00	Homes w/ Dehumidifiers	7.0%	82.2%
1006	Second Refrigerator Turn In	SF	Retrofit	All	1,036.0	100.0%	1036.0	0.15	0.15	0.00	0	8	$120.00	$0.00	Homes w/ more than one refrigerator	40.8%	10.0%
1007	Second Freezer Turn In	SF	Retrofit	All	942.0	100.0%	942.0	0.13	0.13	0.00	0	8	$120.00	$0.00	Homes w/ more than one freezer	10.8%	10.0%
1008	Energy Star Compliant Top-Mount Refrigerator	MH	ROB	All	466.3	10.0%	46.6	0.06	0.06	0.00	0	17	$110.00	$0.00	Homes w/ Refrigerators	98.0%	68.4%
1009	Energy Star Compliant Side-by-Side Refrigerator	MH	ROB	All	550.4	10.0%	55.0	0.07	0.07	0.00	0	17	$110.00	$0.00	Homes w/ Refrigerators	98.0%	68.4%
1010	Energy Star Compliant Chest Freezer	MH	ROB	All	406.9	10.0%	40.7	0.01	0.01	0.00	0	12	$35.00	$0.00	Homes w/ Freezers	50.8%	59.4%
1011	Energy Star Compliant Upright Freezer (Manual Def.)	MH	ROB	All	422.9	10.0%	42.3	0.01	0.01	0.00	0	12	$35.00	$0.00	Homes w/ Freezers	50.8%	59.4%
1012	Energy Star Dehumidifer	MH	ROB	All	1,064.0	20.0%	213.0	0.05	0.05	0.00	0	12	$45.00	$0.00	Homes w/ Dehumidifiers	7.0%	82.2%
1013	Second Refrigerator Turn In	MH	Retrofit	All	1,036.0	100.0%	1036.0	0.15	0.15	0.00	0	8	$120.00	$0.00	Homes w/ more than one refrigerator	11.3%	10.0%
1014	Second Freezer Turn In	MH	Retrofit	All	942.0	100.0%	942.0	0.13	0.13	0.00	0	8	$120.00	$0.00	Homes w/ more than one freezer	8.6%	10.0%
1015	Energy Star Compliant Top-Mount Refrigerator	SF	NC	All	466.3	10.0%	46.6	0.06	0.06	0.00	0	17	$110.00	$0.00	Homes w/ Refrigerators	96.5%	0.0%
1016	Energy Star Compliant Side-by-Side Refrigerator	SF	NC	All	550.4	10.0%	55.0	0.07	0.07	0.00	0	17	$110.00	$0.00	Homes w/ Refrigerators	96.5%	0.0%
1017	Energy Star Compliant Chest Freezer	SF	NC	All	406.9	10.0%	40.7	0.01	0.01	0.00	0	12	$35.00	$0.00	Homes w/ Freezers	63.6%	0.0%
1018	Energy Star Compliant Upright Freezer (Manual Def.)	SF	NC	All	422.9	10.0%	42.3	0.01	0.01	0.00	0	12	$35.00	$0.00	Homes w/ Freezers	63.6%	0.0%
1019	Energy Star Dehumidifer	SF	NC	All	1,064.0	20.0%	213.0	0.05	0.05	0.00	0	12	$45.00	$0.00	Homes w/ Dehumidifiers	7.0%	0.0%
1020	Energy Star Compliant Top-Mount Refrigerator	MH	NC	All	466.3	10.0%	46.6	0.06	0.06	0.00	0	17	$110.00	$0.00	Homes w/ Refrigerators	98.0%	0.0%
1021	Energy Star Compliant Side-by-Side Refrigerator	MH	NC	All	550.4	10.0%	55.0	0.07	0.07	0.00	0	17	$110.00	$0.00	Homes w/ Refrigerators	98.0%	0.0%
1022	Energy Star Compliant Chest Freezer	MH	NC	All	406.9	10.0%	40.7	0.01	0.01	0.00	0	12	$35.00	$0.00	Homes w/ Freezers	50.8%	0.0%
1023	Energy Star Compliant Upright Freezer (Manual Def.)	MH	NC	All	422.9	10.0%	42.3	0.01	0.01	0.00	0	12	$35.00	$0.00	Homes w/ Freezers	50.8%	0.0%
1024	Energy Star Dehumidifer	MH	NC	All	1,064.0	20.0%	213.0	0.05	0.05	0.00	0	12	$45.00	$0.00	Homes w/ Dehumidifiers	7.0%	0.0%
2000	Consumer Electronics - Single Family/Mobile Home																
2001	Efficient Televisions	SF	ROB	All	156.9	49.4%	77.4	0.05	0.05	-0.15	0	10	$30.00	$0.00	Homes w/ a TV	322.0%	88.8%
2002	Energy Star Desktop Computer	SF	ROB	All	239.0	32.2%	77.0	0.009	0.009	-0.14	0	4	$8.00	$0.00	Homes w/ a Desktop	92.0%	28.0%
2003	Energy Star Computer Monitor	SF	ROB	All	66.0	21.2%	14.0	0.002	0.002	-0.03	0	5	$1.80	$0.00	Homes w/ a Desktop	92.0%	77.0%
2004	Energy Star Laptop Computer	SF	ROB	All	76.0	31.6%	24.0	0.003	0.003	-0.04	0	4	$8.00	$0.00	Homes w/ a Laptop	86.0%	75.5%
2005	Smart Strip Power Strip	SF	ROB	All	25.3	80.5%	20.4	0.003	0.003	-0.04	0	4	$16.00	$0.00	Homes w/ home enertertainment or office centers	100.0%	6.0%
2006	Efficient Set Top Box	SF	ROB	All	-	-	94.0	0.011	0.011	0.00	0	4	$5.00	$0.00	Homes with at least one TV	260.8%	63.0%
2007	Efficient Televisions	MH	ROB	All	156.9	49.4%	77.4	0.05	0.05	-0.15	0	10	$30.00	$0.00	Homes w/ a TV	288.0%	88.8%
2008	Energy Star Desktop Computer	MH	ROB	All	239.0	32.2%	77.0	0.009	0.009	-0.14	0	4	$8.00	$0.00	Homes w/ a Desktop	69.0%	28.0%
2009	Energy Star Computer Monitor	MH	ROB	All	66.0	21.2%	14.0	0.002	0.002	-0.03	0	5	$1.80	$0.00	Homes w/ a Desktop	69.0%	77.0%
2010	Energy Star Laptop Computer	MH	ROB	All	76.0	31.6%	24.0	0.003	0.003	-0.04	0	4	$8.00	$0.00	Homes w/ a Laptop	59.0%	75.5%
2011	Smart Strip Power Strip	MH	ROB	All	25.3	80.5%	20.4	0.003	0.003	-0.04	0	4	$16.00	$0.00	Homes w/ home enertertainment or office centers	100.0%	6.0%
2012	Efficient Set Top Box	MH	ROB	All	-	-	94.0	0.011	0.011	0.00	0	4	$5.00	$0.00	Homes with at least one TV	198.7%	63.0%
2013	Efficient Televisions	SF	NC	All	156.9	49.4%	77.4	0.05	0.05	-0.15	0	10	$30.00	$0.00	Homes w/ a TV	322.0%	0.0%
2014	Energy Star Desktop Computer	SF	NC	All	239.0	32.2%	77.0	0.009	0.009	-0.14	0	4	$8.00	$0.00	Homes w/ a Desktop	92.0%	0.0%
2015	Energy Star Computer Monitor	SF	NC	All	66.0	21.2%	14.0	0.002	0.002	-0.03	0	5	$1.80	$0.00	Homes w/ a Desktop	92.0%	0.0%
2016	Energy Star Laptop Computer	SF	NC	All	76.0	31.6%	24.0	0.003	0.003	-0.04	0	4	$8.00	$0.00	Homes w/ a Laptop	86.0%	0.0%
2017	Smart Strip Power Strip	SF	NC	All	25.3	80.5%	20.4	0.003	0.003	-0.04	0	4	$16.00	$0.00	Homes w/ home enertertainment or office centers	100.0%	0.0%
2018	Efficient Set Top Box	SF	NC	All	-	-	94.0	0.011	0.011	0.00	0	4	$5.00	$0.00	Homes with at least one TV	260.8%	0.0%
2019	Efficient Televisions	MH	NC	All	156.9	49.4%	77.4	0.05	0.05	-0.15	0	10	$30.00	$0.00	Homes w/ a TV	288.0%	0.0%
2020	Energy Star Desktop Computer	MH	NC	All	239.0	32.2%	77.0	0.009	0.009	-0.14	0	4	$8.00	$0.00	Homes w/ a Desktop	69.0%	0.0%
2021	Energy Star Computer Monitor	MH	NC	All	66.0	21.2%	14.0	0.002	0.002	-0.03	0	5	$1.80	$0.00	Homes w/ a Desktop	69.0%	0.0%
2022	Energy Star Laptop Computer	MH	NC	All	76.0	31.6%	24.0	0.003	0.003	-0.04	0	4	$8.00	$0.00	Homes w/ a Laptop	59.0%	0.0%
2023	Smart Strip Power Strip	MH	NC	All	25.3	80.5%	20.4	0.003	0.003	-0.04	0	4	$16.00	$0.00	Homes w/ home enertertainment or office centers	100.0%	0.0%
2024	Efficient Set Top Box	MH	NC	All	-	-	94.0	0.011	0.011	0.00	0	4	$5.00	$0.00	Homes with at least one TV	198.7%	0.0%
3000	Lighting - Single Family /Mobile Home																
3001	Standard CFL - Average Use (3 hours/day)	SF	ROB	All	43.7	57.1%	24.9	0.03	0.03	-0.05	0	5	$3.00	$0.80	Sockets with standard Inc. bulbs	2451.7%	50.0%
3002	Standard LED - Average Use (3 hours/day)	SF	ROB	All	43.7	65.0%	28.4	0.03	0.03	-0.1	0	15	$15.00	$0.93	Sockets with standard Inc. bulbs	2451.7%	50.0%
3003	Specialty CFL	SF	ROB	All	69.2	67.2%	46.5	0.05	0.05	-0.08	0	10	$4.00	$0.90	Sockets with specialty Inc. bulbs	1546.3%	50.0%
3004	Specialty LED	SF	ROB	All	72.8	73.9%	53.8	0.06	0.06	-0.10	0	20	$70.00	$0.95	Sockets with specialty Inc. bulbs	1546.3%	50.0%
3005	Energy Star Torchiere	SF	ROB	All	174.7	64.9%	113.4	0.12	0.12	-0.22	0	7	$5.00	$2.60	Halogen torchiere fixtures	77.0%	50.0%
3006	LED Nightlight	SF	ROB	All	14.6	93.2%	13.6	0.00	0.00	0.00	0	16	$3.00	$0.94	Incandescent nightlights	25.0%	10.0%
3007	Exterior CFL Fixture	SF	ROB	All	148.4	56.4%	83.6	0.05	0.05	0.00	0	20	$17.00	$0.95	Exterior lighting with incandescent bulbs	800.0%	50.0%
3008	Exterior LED Fixture	SF	ROB	All	148.4	70.1%	104.0	0.06	0.06	0.00	0	20	$20.00	$0.95	Exterior lighting with incandescent bulbs	800.0%	50.0%
3009	Standard CFL - Average Use (3 hours/day)	MH	ROB	All	43.7	57.1%	24.9	0.03	0.03	-0.05	0	5	$3.00	$0.80	Sockets with standard Inc. bulbs	1864.0%	48.5%
3010	Standard LED - Average Use (3 hours/day)	MH	ROB	All	43.7	65.0%	28.4	0.03	0.03	-0.05	0	15	$15.00	$0.93	Sockets with standard Inc. bulbs	1864.0%	48.5%
3011	Specialty CFL	MH	ROB	All	69.2	67.2%	46.5	0.05	0.05	-0.08	0	10	$4.00	$0.90	Sockets with specialty Inc. hulbs	1175.6%	48.5%
3012	Specialty LED	MH	ROB	All	72.8	73.9%	53.8	0.06	0.06	-0.10	0	20	$70.00	$0.95	Sockets with specialty Inc. bulbs	1175.6%	48.5%
3013	Energy Star Torchiere	MH	ROB	All	174.7	64.9%	113.4	0.12	0.12	-0.22	0	7	$5.00	$2.60	Halogen torchiere fixtures	42.3%	48.5%
3014	LED Nightlight	MH	ROB	All	14.6	93.2%	13.6	0.00	0.00	0.00	0	16	$3.00	$0.94	Incandescent nightlights	25.0%	10.0%
3015	Exterior CFL Fixture	MH	ROB	All	148.4	56.4%	83.6	0.05	0.05	0.00	0	20	$17.00	$0.95	Exterior lighting with incandescent bulbs	400.0%	48.5%
3016	Exterior LED Fixture	MH	ROB	All	148.4	70.1%	104.0	0.06	0.06	0.00	0	20	$20.00	$0.95	Exterior lighting with incandescent bulbs	400.0%	48.5%
3017	Standard CFL - Average Use (3 honrs/day)	SF	NC	All	43.7	57.1%	24.9	0.03	0.03	-0.05	0	5	$3.00	$0.80	Sockets with standard Inc. bulbs	2451.7%	0.0%
3018	Standard LED - Average Use (3 hours/day)	SF	NC	All	43.7	65.0%	28.4	0.03	0.03	-0.1	0	15	$15.00	$0.93	Sockets with standard Inc. bulbs	2451.7%	0.0%
3019	Specialty CFL	SF	NC	All	69.2	67.2%	46.5	0.05	0.05	-0.08	0	10	$4.00	$0.90	Sockets with specialty Inc. bulbs	1546.3%	0.0%
3020	Specialty LED	SF	NC	All	72.8	73.9%	53.8	0.06	0.06	-0.10	0	20	$70.00	$0.95	Sockets with specialty Inc. bulbs	1546.3%	0.0%
3021	Energy Star Torchiere	SF	NC	All	174.7	64.9%	113.4	0.12	0.12	-0.22	0	7	$5.00	$2.60	Halogen torchiere fixtures	77.0%	0.0%

Big Rivers - Residential Measure Database

Measure ID	Measure Name	Home Type (DET/ATT/MF/MF-SM/MF-MM)	ROB vs. Retrofit vs. ER vs. NC	Income Target (All / LI)	Base Elec. Use (kWh)	% Savings	Annual kWh Savings	Per Unit Winter NCP kW Savings	Per Unit Summer NCP kW Savings	Annual Non-elec. Savings (MMBTU)	Annual Water Savings (gal)	Useful Life	Incremental /Full Cost	O&M Savings	Measure/End Use Description	Base Saturation	EE Saturation
3022	LED Nightlight	SF	NC	All	14.6	93.2%	13.6	0.00	0.00	0.00	0	16	$3.00	$0.94	Incandescent nightlights	25.0%	0.0%
3023	Exterior CFL Fixture	SF	NC	All	148.4	56.4%	83.6	0.05	0.05	0.00	0	20	$17.00	$0.95	Exterior lighting with incandescent bulbs	800.0%	0.0%
3024	Exterior LED Fixture	SF	NC	All	148.4	70.1%	104.0	0.06	0.06	0.00	0	20	$20.00	$0.95	Exterior lighting with incandescent bulbs	800.0%	0.0%
3025	Standard CFL - Average Use (3 hours/day)	MH	NC	All	43.7	57.1%	24.9	0.03	0.03	-0.05	0	5	$3.00	$0.80	Sockets with standard Inc. bulbs	1864.0%	0.0%
3026	Standard LED - Average Use (3 hours/day)	MH	NC	All	43.7	65.0%	28.4	0.03	0.03	-0.05	0	15	$15.00	$0.93	Sockets with standard Inc. bulbs	1864.0%	0.0%
3027	Specialty CFL	MH	NC	All	69.2	67.2%	46.5	0.05	0.05	-0.08	0	10	$4.00	$0.90	Sockets with specialty Inc. bulbs	1175.6%	0.0%
3028	Specialty LED	MH	NC	All	72.8	73.9%	53.8	0.06	0.06	-0.10	0	20	$70.00	$0.95	Sockets with specialty Inc. bulbs	1175.6%	0.0%
3029	Energy Star Torchiere	MH	NC	All	174.7	64.9%	113.4	0.12	0.12	-0.22	0	7	$5.00	$2.60	Halogen torchiere fixtures	42.3%	0.0%
3030	LED Nightlight	MH	NC	All	14.6	93.2%	13.6	0.00	0.00	0.00	0	16	$3.00	$0.94	Incandescent nightlights	25.0%	0.0%
3031	Exterior CFL Fixture	MH	NC	All	148.4	56.4%	83.6	0.05	0.05	0.00	0	20	$17.00	$0.95	Exterior lighting with incandescent bulbs	400.0%	0.0%
3032	Exterior LED Fixture	MH	NC	All	148.4	70.1%	104.0	0.06	0.06	0.00	0	20	$20.00	$0.95	Exterior lighting with incandescent bulbs	400.0%	0.0%
4000	Electric Water Heating - Single Family/Mobile Homes																
4001	Low Flow Faucet Aerators	SF	Retrofit	All	74.8	49.4%	37.0	0.01	0.01	0.00	636	10	$8.00	$0.00	Homes w/ Electric WH	204.3%	77.0%
4002	Low Flow Showerhead	SF	Retrofit	All	1,464.6	28.6%	418.4	0.17	0.17	0.00	3483	5	$12.00	$0.00	Homes w/ Electric WH	97.7%	72.0%
4003	Water Heater Blanket	SF	Retrofit	All	3,460.0	2.3%	79.0	0.01	0.01	0.00	0	5	$35.00	$0.00	Homes w/ Electric WH	58.4%	9.0%
4004	Water Heater Pipe Wrap	SF	Retrofit	All	166.8	79.7%	133.0	0.02	0.02	0.00	0	15	$15.00	$0.00	Homes w/ Electric WH	58.4%	24.0%
4005	Heat Pump Water Heater (resistance heat)	SF	ROB	All	3,460.0	14.4%	499.0	0.20	0.20	0.00	0	10	$700.00	$0.00	Homes w/ Electric WH & elec resistance heating	39.2%	5.0%
4006	Heat Pump Water Heater (ASHP heat)	SF	ROB	All	3,460.0	37.5%	1297.0	0.51	0.51	0.00	0	10	$700.00	$0.00	Homes w/ Electric WH & ASHP heating	19.1%	5.0%
4007	Solar Water Heating	SF	Retrofit	All	3,460.0	71.1%	2461.0	1.93	1.93	0.00	0	20	$9,506.00	-$344.00	Homes w/ Electric WH	58.4%	5.0%
4008	Energy Star Dishwasher (Electric Water Heating)	SF	ROB	All	307.0	8.8%	27.0	0.05	0.05	0.00	215	11	$10.00	$0.00	Homes w/ Dishwashers & Electric WH	48.4%	75.5%
4009	Energy Star Dishwasher (Non-Electric WH)	SF	ROB	All	135.1	8.8%	11.9	0.04	0.04	0.07	215	11	$10.00	$0.00	Homes w/ Dishwashers & Non-Elec. WH	34.2%	75.5%
4010	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	ROB	All	450.0	31.2%	140.2	0.44	0.44	0.00	4337	11	$186.00	$0.00	Homes w/ CW, Elec. WH and Elec. Dryer	55.6%	77.0%
4011	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	SF	ROB	All	300.0	34.6%	103.7	0.32	0.32	0.00	4337	11	$186.00	$0.00	Homes w/ CW, NG WH and Elec. Dryer	39.2%	77.0%
4012	Low Flow Faucet Aerators	MH	Retrofit	All	74.8	49.4%	37.0	0.01	0.01	0.00	636	10	$8.00	$0.00	Homes w/ Electric WH	321.7%	87.0%
4013	Low Flow Showerhead	MH	Retrofit	All	1,464.6	28.6%	418.4	0.17	0.17	0.00	3483	5	$12.00	$0.00	Homes w/ Electric WH	93.4%	75.0%
4014	Water Heater Blanket	MH	Retrofit	All	3,460.0	2.3%	79.0	0.01	0.01	0.00	0	5	$35.00	$0.00	Homes w/ Electric WH	91.9%	0.0%
4015	Water Heater Pipe Wrap	MH	Retrofit	All	166.8	79.7%	133.0	0.02	0.02	0.00	0	15	$15.00	$0.00	Homes w/ Electric WH	91.9%	11.0%
4016	Energy Star Dishwasher (Electric Water Heating)	MH	ROB	All	307.0	8.8%	27.0	0.05	0.05	0.00	215	11	$10.00	$0.00	Homes w/ Dishwashers & Electric WH	54.4%	73.4%
4017	Energy Star Dishwasher (Non-Electric WH)	MH	ROB	All	135.1	8.8%	11.9	0.04	0.04	0.07	215	11	$10.00	$0.00	Homes w/ Dishwashers & Non-Elec. WH	4.8%	73.4%
4018	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	ROB	All	450.0	31.2%	140.2	0.44	0.44	0.00	4337	11	$186.00	$0.00	Homes w/ CW, Elec. WH and Elec. Dryer	52.7%	74.0%
4019	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	MH	ROB	All	300.0	34.6%	103.7	0.32	0.32	0.00	4337	11	$186.00	$0.00	Homes w/ CW, NG WH and Elec. Dryer	37.2%	74.0%
4020	Low Flow Faucet Aerators	SF	NC	All	74.8	49.4%	37.0	0.01	0.01	0.00	636	10	$8.00	$0.00	Homes w/ Electric WH	204.3%	0.0%
4021	Low Flow Showerhead	SF	NC	All	1,464.6	28.6%	418.4	0.17	0.17	0.00	3483	5	$12.00	$0.00	Homes w/ Electric WH	97.7%	0.0%
4022	Water Heater Blanket	SF	NC	All	3,460.0	2.3%	79.0	0.01	0.01	0.00	0	5	$35.00	$0.00	Homes w/ Electric WH	58.4%	0.0%
4023	Water Heater Pipe Wrap	SF	NC	All	166.8	79.7%	133.0	0.02	0.02	0.00	0	15	$15.00	$0.00	Homes w/ Electric WH	58.4%	0.0%
4024	Heat Pump Water Heater (ASHP heat)	SF	NC	All	3,460.0	37.5%	1297.0	0.51	0.51	0.00	0	10	$700.00	$0.00	Homes w/ Electric WH & ASHP heating	58.4%	0.0%
4025	Solar Water Heating	SF	NC	All	3,460.0	71.1%	2461.0	1.93	1.93	0.00	0	20	$9,506.00	-$344.00	Homes w/ Electric WH	58.4%	0.0%
4026	Energy Star Dishwasher (Electric Water Heating)	SF	NC	All	307.0	8.8%	27.0	0.05	0.05	0.00	215	11	$10.00	$0.00	Homes w/ Dishwashers & Electric WH	48.4%	0.0%
4027	Energy Star Dishwasher (Non-Electric WH)	SF	NC	All	135.1	8.8%	11.9	0.04	0.04	0.07	215	11	$10.00	$0.00	Homes w/ Dishwashers & Non-Elec. WH	34.2%	0.0%
4028	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	NC	All	450.0	31.2%	140.2	0.44	0.44	0.00	4337	11	$186.00	$0.00	Homes w/ CW, Elec. WH and Elec. Dryer	55.6%	0.0%
4029	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	SF	NC	All	300.0	34.6%	103.7	0.32	0.32	0.00	4337	11	$186.00	$0.00	Homes w/ CW, NG WH and Elec. Dryer	39.2%	0.0%
4030	Low Flow Faucet Aerators	MH	NC	All	74.8	49.4%	37.0	0.01	0.01	0.00	636	10	$8.00	$0.00	Homes w/ Electric WH	321.7%	0.0%
4031	Low Flow Showerhead	MH	NC	All	1,464.6	28.6%	418.4	0.17	0.17	0.00	3483	5	$12.00	$0.00	Homes w/ Electric WH	93.4%	0.0%
4032	Water Heater Blanket	MH	NC	All	3,460.0	2.3%	79.0	0.01	0.01	0.00	0	5	$35.00	$0.00	Homes w/ Electric WH	91.9%	0.0%
4033	Water Heater Pipe Wrap	MH	NC	All	166.8	79.7%	133.0	0.02	0.02	0.00	0	15	$15.00	$0.00	Homes w/ Electric WH	91.9%	0.0%
4034	Energy Star Dishwasher (Electric Water Heating)	MH	NC	All	307.0	8.8%	27.0	0.05	0.05	0.00	215	11	$10.00	$0.00	Homes w/ Dishwashers & Electric WH	54.4%	0.0%
4035	Energy Star Dishwasher (Non-Electric WH)	MH	NC	All	135.1	8.8%	11.9	0.04	0.04	0.07	215	11	$10.00	$0.00	Homes w/ Dishwashers & Non-Elec. WH	4.8%	0.0%
4036	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	NC	All	450.0	31.2%	140.2	0.44	0.44	0.00	4337	11	$186.00	$0.00	Homes w/ CW, Elec. WH and Elec. Dryer	52.7%	0.0%
4037	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	MH	NC	All	300.0	34.6%	103.7	0.32	0.32	0.00	4337	11	$186.00	$0.00	Homes w/ CW, NG WH and Elec. Dryer	37.2%	0.0%
5000	Space Heating and Space Cooling Shell Measures - Single Family Homes w/ Electric AC Only (& Gas Heat)																
5001	Insulation - Ceiling (R-0 to R-19)	SF	Retrofit	All	3,786.0	12.2%	463.0	0.1	1.0	46.70	0	25	$2,538.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	90.1%
5002	Insulation - Floor (R-0 to R-19)	SF	Retrofit	All	3,205.0	-3.7%	-118.0	0.0	0.1	14.40	0	25	$1,728.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	37.1%
5003	Energy Star Windows	SF	Retrofit	All	3,323.0	11.2%	373.0	0.0	0.2	4.00	0	25	$6,146.74	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	54.0%
5004	Insulation -Ceiling (R-19 to R-38)	SF	Retrofit	All	3,323.0	1.8%	59.0	0.0	0.1	6.70	0	25	$2,538.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	37.0%
5005	Insulation -Ceiling (R-0 to R-38)	SF	Retrofit	All	3,786.0	13.8%	522.0	0.1	1.1	53.40	0	25	$3,276.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	90.1%
5006	Insulation -Ceiling (R-9 to R-38)	SF	Retrofit	All	3,371.0	3.2%	107.0	0.0	0.2	12.20	0	25	$3,186.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	37.0%
5007	Insulation -Ceiling (R-11 to R-38)	SF	Retrofit	All	3,356.0	2.7%	92.0	0.0	0.2	10.50	0	25	$3,114.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	37.0%
5008	Air Sealing	SF	Retrofit	All	3,323.0	1.1%	35.0	0.0	0.1	5.00	0	15	$738.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	68.5%
5009	Duct Sealing	SF	Retrofit	All	3,323.0	5.9%	196.0	0.0	0.3	1.40	0	20	$576.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	68.5%
5010	Radiant Barriers	SF	Retrofit	All	3,323.0	8.8%	293.0	0.0	0.5	0.00	0	25	$450.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	10.0%
5011	Complete Weatherization Package	SF	Retrofit	All	4,196.8	17.4%	730.0	0.59	0.99	9.00	7799	13	$2,171.20	$16.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	68.5%
5012	Energy Star Windows	SF	NC	All	2,423.0	-0.1%	-3.0	0.0	0.0	1.20	0	25	$405.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	0.0%
5013	Insulation -Ceiling (R-38 Grade 2 to Grade 1)	SF	NC	All	2,423.0	0.0%	1.0	0.0	0.0	0.10	0	25	$126.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	0.0%
5014	Air Sealing	SF	NC	All	2,423.0	0.4%	9.0	0.0	0.1	3.90	0	15	$396.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	0.0%
5015	Duct Sealing	SF	NC	All	2,423.0	7.0%	170.0	0.0	0.4	1.20	0	20	$73.44	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	0.0%
5016	Radiant Barriers	SF	NC	All	2,423.0	6.2%	150.0	0.0	0.4	0.10	0	25	$342.54	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	0.0%
6000	Space Heating and Space Cooling Shell Measures - Single Family Homes w/ Electric Heat Pump																
6001	Insulation - Ceiling (R-0 to R-19)	SF	Retrofit	All	17,229.0	39.8%	6860.0	4.1	1.0	0.00	0	25	$2,538.00	$0.00	Homes w/ Electric Heat Pump	24.1%	90.1%
6002	Insulation - Floor (R-0 to R-19)	SF	Retrofit	All	12,086.0	14.2%	1717.0	1.0	0.1	0.00	0	25	$1,728.00	$0.00	Homes w/ Electric Heat Pump	24.1%	37.1%
6003	Energy Star Windows	SF	Retrofit	All	10,369.0	8.4%	870.0	0.8	0.2	0.00	0	25	$6,146.74	$0.00	Homes w/ Electric Heat Pump	24.1%	54.0%
6004	Insulation -Ceiling (R-19 to R-38)	SF	Retrofit	All	10,369.0	8.7%	897.0	0.6	0.2	0.00	0	25	$2,538.00	$0.00	Homes w/ Electric Heat Pump	24.1%	37.0%
6005	Insulation -Ceiling (R-0 to R-38)	SF	Retrofit	All	17,229.0	45.0%	7757.0	4.7	1.2	0.00	0	25	$3,276.00	$0.00	Homes w/ Electric Heat Pump	24.1%	90.1%
6006	Insulation -Ceiling (R-9 to R-38)	SF	Retrofit	All	11,114.0	14.8%	1642.0	1.1	0.3	0.00	0	25	$3,186.00	$0.00	Homes w/ Electric Heat Pump	24.1%	37.0%
6007	Insulation -Ceiling (R-11 to R-38)	SF	Retrofit	All	10,882.0	13.0%	1410.0	0.9	0.3	0.00	0	25	$3,114.00	$0.00	Homes w/ Electric Heat Pump	24.1%	37.0%

Big Rivers - Residential Measure Database

Measure ID	Measure Name	Home Type (DET/ATT/MF/MF SM/MF-MM)	ROB vs. Retrofit vs. ER vs. NC	Income Target (All / LI)	Base Elec. Use (kWh)	% Savings	Annual kWh Savings	Per Unit Winter NCP kW Savings	Per Unit Summer NCP kW Savings	Annual Non-elec Savings (MMBTU)	Annual Water Savings (gal.)	Useful Life	Incremental /Full Cost	O&M Savings	Measure/End Use Description	Base Saturation	EE Saturation
6008	Air Sealing	SF	Retrofit	All	10,369.0	6.4%	663.0	0.5	0.1	0.00	0	15	$738.00	$0.00	Homes w/ Electric Heat Pump	24.1%	68.5%
6009	Duct Sealing	SF	Retrofit	All	10,369.0	3.7%	379.0	2.1	0.3	0.00	0	20	$576.00	$0.00	Homes w/ Electric Heat Pump	24.1%	68.5%
6010	Radiant Barriers	SF	Retrofit	All	10,369.0	2.9%	303.0	0.1	0.5	0.00	0	25	$450.00	$0.00	Homes w/ Electric Heat Pump	24.1%	10.0%
6011	Complete Weatherization Package	SF	Retrofit	All	13,847.9	28.8%	3981.8	4.61	1.61	0.00	7799	13	$5,357.20	$16.00	Homes w/ Electric Heat Pump	24.1%	68.5%
6012	Energy Star Windows	SF	NC	All	7,517.0	1.6%	122.0	0.1	0.0	0.00	0	25	$405.00	$0.00	Homes w/ Electric Heat Pump	40.1%	0.0%
6013	Insulation -Ceiling (R-38 Grade 2 to Grade 1)	SF	NC	All	7,517.0	0.1%	5.0	0.0	0.0	0.00	0	25	$126.00	$0.00	Homes w/ Electric Heat Pump	40.1%	0.0%
6014	Air Sealing	SF	NC	All	7,517.0	5.8%	433.0	0.1	0.0	0.00	0	15	$396.00	$0.00	Homes w/ Electric Heat Pump	40.1%	0.0%
6015	Duct Sealing	SF	NC	All	7,517.0	3.1%	236.0	2.2	0.3	0.00	0	20	$73.44	$0.00	Homes w/ Electric Heat Pump	40.1%	0.0%
6016	Radiant Barriers	SF	NC	All	7,517.0	1.9%	146.0	0.1	0.4	0.00	0	25	$342.54	$0.00	Homes w/ Electric Heat Pump	40.1%	0.0%
7000	Space Heating and Space Cooling Shell Measures - Single Family Homes w/ Electric Furnace																
7001	Insulation - Ceiling (R-0 to R-19)	SF	Retrofit	All	28,444.0	40.1%	11399.0	4.2	1.0	0.00	0	25	$2,538.00	$0.00	Homes w/ Electric Furnace & AC	16.0%	90.1%
7002	Insulation - Floor (R-0 to R-19)	SF	Retrofit	All	20,293.0	16.0%	3248.0	1.0	0.1	0.00	0	25	$1,728.00	$0.00	Homes w/ Electric Furnace & AC	16.0%	37.1%
7003	Energy Star Windows	SF	Retrofit	All	17,045.0	7.6%	1289.0	0.8	0.2	0.00	0	25	$6,146.74	$0.00	Homes w/ Electric Furnace & AC	16.0%	54.0%
7004	Insulation -Ceiling (R-19 to R-38)	SF	Retrofit	All	17,045.0	9.6%	1631.0	0.6	0.2	0.00	0	25	$2,538.00	$0.00	Homes w/ Electric Furnace & AC	16.0%	37.0%
7005	Insulation -Ceiling (R-0 to R-38)	SF	Retrofit	All	28,444.0	45.8%	13030.0	4.8	1.2	0.00	0	25	$3,276.00	$0.00	Homes w/ Electric Furnace & AC	16.0%	90.1%
7006	Insulation -Ceiling (R-9 to R-38)	SF	Retrofit	All	18,378.0	16.1%	2964.0	1.0	0.3	0.00	0	25	$3,186.00	$0.00	Homes w/ Electric Furnace & AC	16.0%	37.0%
7007	Insulation -Ceiling (R-11 to R-38)	SF	Retrofit	All	17,965.0	14.2%	2551.0	0.9	0.3	0.00	0	25	$3,114.00	$0.00	Homes w/ Electric Furnace & AC	16.0%	37.0%
7008	Air Sealing	SF	Retrofit	All	17,045.0	7.1%	1210.0	0.5	0.1	0.00	0	15	$738.00	$0.00	Homes w/ Electric Furnace & AC	16.0%	68.5%
7009	Duct Sealing	SF	Retrofit	All	17,045.0	3.0%	516.0	2.2	0.3	0.00	0	20	$576.00	$0.00	Homes w/ Electric Furnace & AC	16.0%	68.5%
7010	Radiant Barriers	SF	Retrofit	All	17,045.0	0.0%	8.0	0.1	0.5	0.00	0	25	$450.00	$0.00	Homes w/ Electric Furnace & AC	16.0%	10.0%
7011	Complete Weatherization Package	SF	Retrofit	All	20,523.9	29.2%	5987.8	4.61	1.61	0.00	7799	13	$5,357.20	$16.00	Homes w/ Electric Furnace & AC	16.0%	68.5%
8000	Space Heating and Space Cooling Shell Measures - Mobile Homes w/ Electric AC Only (& Gas Heat)																
8001	Air Sealing	MH	Retrofit	All	2,147.0	1.3%	28.0	0.00	0.00	2.5	0	15	$410.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	17.6%	68.5%
8002	Insulation - Floor (R-11 to R-30)	MH	Retrofit	All	2,147.0	-0.5%	-11.0	0.00	0.00	3.2	0	25	$960.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	17.6%	37.0%
8003	Energy Star Windows	MH	Retrofit	All	2,147.0	3.7%	79.0	0.00	0.10	6.5	0	25	$3,414.85	$0.00	Homes w/ Electric AC Only (& Gas Heat)	17.6%	54.0%
8004	Duct Sealing	MH	Retrofit	All	2,147.0	8.4%	180.0	0.10	0.20	1.2	0	20	$320.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	17.6%	68.5%
8005	Complete Weatherization Package	MH	Retrofit	All	3,020.8	23.0%	696.0	0.69	0.79	9.50	7799	13	$2,547.20	$16.00	Homes w/ Electric AC Only (& Gas Heat)	17.6%	68.5%
8006	Air Sealing	MH	NC	All	1,563.0	0.6%	10.0	0.00	0.00	3.9	0	15	$264.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	17.6%	0.0%
8007	Insulation - Floor (R-19 to R-30)	MH	NC	All	1,563.0	-0.1%	-1.0	0.00	0.00	4.3	0	25	$480.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	17.6%	0.0%
8008	Energy Star Windows	MH	NC	All	1,563.0	0.0%	0.0	0.00	0.00	2.7	0	25	$225.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	17.6%	0.0%
8009	Duct Sealing	MH	NC	All	1,563.0	10.6%	166.0	0.00	0.20	3.0	0	20	$40.80	$0.00	Homes w/ Electric AC Only (& Gas Heat)	17.6%	0.0%
9000	Space Heating and Space Cooling Shell Measures - Mobile Homes w/ Electric Heat Pump																
9001	Air Sealing	MH	Retrofit	All	7,400.0	4.6%	338.0	0.00	0.00	0.0	0	15	$410.00	$0.00	Homes w/ Electric Heat Pump	8.9%	68.5%
9002	Insulation - Floor (R-11 to R-30)	MH	Retrofit	All	7,400.0	5.2%	386.0	0.40	0.00	0.0	0	25	$960.00	$0.00	Homes w/ Electric Heat Pump	8.9%	37.0%
9003	Energy Star Windows	MH	Retrofit	All	7,400.0	11.9%	879.0	0.80	0.10	0.0	0	25	$3,414.85	$0.00	Homes w/ Electric Heat Pump	8.9%	54.0%
9004	Duct Sealing	MH	Retrofit	All	7,400.0	4.2%	308.0	2.50	0.30	0.0	0	20	$320.00	$0.00	Homes w/ Electric Heat Pump	8.9%	68.5%
9005	Complete Weatherization Package	MH	Retrofit	All	10,878.9	21.4%	2329.8	3.81	1.21	0.00	7799	13	$2,547.20	$16.00	Homes w/ Electric Heat Pump	8.9%	68.5%
9006	Air Sealing	MH	NC	All	4,351.0	4.7%	206.0	0.00	0.00	0.0	0	15	$264.00	$0.00	Homes w/ Electric Heat Pump	68.2%	0.0%
9007	Insulation - Floor (R-19 to R-30)	MH	NC	All	4,351.0	5.4%	233.0	0.30	0.00	0.0	0	25	$480.00	$0.00	Homes w/ Electric Heat Pump	68.2%	0.0%
9008	Energy Star Windows	MH	NC	All	4,351.0	1.4%	63.0	0.10	0.00	0.0	0	25	$225.00	$0.00	Homes w/ Electric Heat Pump	68.2%	0.0%
9009	Duct Sealing	MH	NC	All	4,351.0	4.8%	211.0	2.70	0.30	0.0	0	20	$40.80	$0.00	Homes w/ Electric Heat Pump	68.2%	0.0%
10000	Space Heating and Space Cooling Shell Measures - Mobile Homes w/ Electric Heat																
10001	Air Sealing	MH	Retrofit	All	12,309.0	5.0%	617.0	0.00	0.00	0.0	0	15	$410.00	$0.00	Homes w/ Electric Heat & Cool	59.3%	68.5%
10002	Insulation - Floor (R-11 to R-30)	MH	Retrofit	All	12,309.0	6.0%	736.0	0.30	0.00	0.0	0	25	$960.00	$0.00	Homes w/ Electric Heat & Cool	59.3%	37.0%
10003	Energy Star Windows	MH	Retrofit	All	12,309.0	13.0%	1595.0	0.70	0.10	0.0	0	25	$3,414.85	$0.00	Homes w/ Electric Heat & Cool	59.3%	54.0%
10004	Duct Sealing	MH	Retrofit	All	12,309.0	3.7%	450.0	2.50	0.30	0.0	0	20	$320.00	$0.00	Homes w/ Electric Heat & Cool	59.3%	68.5%
10005	Complete Weatherization Package	MH	Retrofit	All	15,787.9	19.6%	3100.8	3.71	1.21	0.00	7799	13	$2,547.20	$16.00	Homes w/ Electric Heat & Cool	59.3%	68.5%
11000	Space Heating and Space Cooling Equipment - Single Family/Mobile Homes																
11001	HVAC Tune-Up (Central AC)	SF	Retrofit	All	2,763.0	5.0%	138.2	0.2	0.2	0.00	0	5	$160.00	$0.00	Homes w/ Electric Central AC	88.2%	35.0%
11002	HVAC Tune-Up (Heat Pump)	SF	Retrofit	All	10,869.0	5.0%	543.5	0.4	0.2	0.00	0	5	$160.00	$0.00	Homes with Electric Heat Pump (H&C)	24.1%	35.0%
11003	Energy Star Room A/C	SF	ROB	All	454.1	11.3%	51.4	0.113	0.113	0.00	0	9	$60.00	$0.00	Homes w/ Electric Room AC	18.7%	23.0%
11004	High Efficiency Central AC - 16 SEER	SF	ROB	All	2,271.0	15.9%	360.0	0.0	0.3	0.00	0	18	$2,007.00	$0.00	Homes w/ Electric Central AC	88.2%	9.0%
11005	Ductless mini-split AC	SF	ROB	All	2,271.0	42.3%	960.0	0.0	1.7	0.00	0	15	$3,306.72	$0.00	Homes w/ Electric Central AC	88.2%	9.0%
11006	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	ROB	All	9,193.0	6.7%	613.0	0.0	0.2	0.00	0	18	$1,523.00	$0.00	Homes with Electric Heat Pump (H&C)	24.1%	9.0%
11007	Ground Source Heat Pump (HP Upgrade)	SF	ROB	All	9,193.0	47.5%	4371.0	0.0	0.3	0.00	0	18	$11,772.00	$0.00	Homes with Electric Heat Pump (H&C)	24.1%	9.0%
11008	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	SF	ROB	All	16,746.0	48.8%	8166.0	0.3	0.5	0.00	0	18	$4,623.00	$0.00	Homes with Electric Furnaces and CAC	16.0%	0.0%
11009	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	SF	ROB	All	9,193.0	46.3%	4260.0	3.5	0.2	-12.70	0	18	$3,196.00	$0.00	Homes with Electric Heat Pump (H&C)	24.1%	9.0%
11010	Dual Fuel Heat Pump (Replacing Electric Furnace)	SF	ROB	All	16,746.0	70.5%	11813.0	3.8	0.5	-12.70	0	18	$8,925.00	$0.00	Homes with Electric Furnaces and CAC	16.0%	0.0%
11011	Ductless mini-split HP (replacing ASHP)	SF	Retrofit	All	9,193.0	19.2%	1762.0	3.7	1.4	0.00	0	15	$7,595.82	$0.00	Homes with Electric Heat Pump (H&C)	24.1%	9.0%
11012	Ductless mini-split HP (replacing furnace)	SF	Retrofit	All	16,746.0	55.6%	9315.0	4.0	1.7	0.00	0	15	$13,323.82	$0.00	Homes with Electric Furnaces and CAC	16.0%	0.0%
11013	ECM Furnace Fan	SF	ROB	All	1,543.7	33.3%	514.6	0.073	0.073	0.00	0	10	$250.00	$0.00	Homes with furnaces	49.4%	25.0%
11014	Programmable Thermostat - Gas/AC	SF	Retrofit	All	3,323.0	8.5%	283.7	0.0	0.0	3.98	0	15	$35.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	20.0%
11015	Programmable Thermostat - ASHP	SF	Retrofit	All	10,369.0	7.3%	761.6	0.0	0.0	0.00	0	15	$35.00	$0.00	Homes with Electric Heat Pump (H&C)	24.1%	20.0%
11016	Programmable Thermostat - Elec Furnace/AC	SF	Retrofit	All	17,045.0	7.1%	1215.6	0.0	0.0	0.00	0	15	$35.00	$0.00	Homes with Electric Furnaces and CAC	16.0%	20.0%
11017	Smart Thermostat - Gas Heat / AC	SF	Retrofit	All	3,323.0	8.5%	283.7	0.0	0.0	3.98	0	15	$249.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	20.0%
11018	Smart Thermostat - ASHP	SF	Retrofit	All	10,369.0	7.3%	761.6	0.0	0.0	0.00	0	15	$249.00	$0.00	Homes with Electric Heat Pump (H&C)	24.1%	20.0%
11019	Smart Thermostat - Elec Furnace/AC	SF	Retrofit	All	17,045.0	7.1%	1215.6	0.0	0.0	0.00	0	15	$249.00	$0.00	Homes with Electric Furnaces and CAC	16.0%	20.0%
11020	HVAC Tune-Up (Central AC)	MH	Retrofit	All	1,621.0	5.0%	81.1	0.21	0.21	0.00	0	5	$160.00	$0.00	Homes w/ Electric Central AC	78.4%	35.0%
11021	HVAC Tune-Up (Heat Pump)	MH	Retrofit	All	7,764.0	5.0%	388.2	0.29	0.21	0.00	0	5	$160.00	$0.00	Homes with Electric Heat Pump (H&C)	8.9%	35.0%
11022	Energy Star Room A/C	MH	ROB	All	454.1	11.3%	51.4	0.113	0.113	0.00	0	9	$60.00	$0.00	Homes w/ Electric Room AC	41.6%	4.0%
11023	High Efficiency Central AC - 16 SEER	MH	ROB	All	1,333.0	15.8%	211.0	0.00	0.20	0.00	0	18	$1,916.00	$0.00	Homes w/ Electric Central AC	78.4%	0.0%
11024	Ductless mini-split AC	MH	ROB	All	1,540.0	41.9%	645.0	0.00	1.30	0.00	0	15	$2,480.04	$0.00	Homes w/ Electric Central AC	78.4%	0.0%
11025	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	ROB	All	6,605.0	6.3%	419.0	0.00	0.10	0.00	0	18	$1,409.00	$0.00	Homes with Electric Heat Pump (H&C)	8.9%	0.0%
11026	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	MH	ROB	All	12,152.0	49.1%	5966.0	0.20	0.20	0.00	0	18	$4,287.00	$0.00	Homes with Electric Furnaces and CAC	59.3%	0.0%
11027	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	MH	ROB	All	6,605.0	49.6%	3277.0	3.20	0.10	-9.90	0	18	$3,082.00	$0.00	Homes with Electric Heat Pump (H&C)	8.9%	0.0%

Big Rivers - Residential Measure Database

Measure ID	Measure Name	Home Type (DET/AT T/MF/MF-SM/MF-MM)	ROB vs. Retrofit vs. ER vs. NC	Income Target (All / LI)	Base Elec. Use (kWh)	% Savings	Annual kWh Savings	Per Unit Winter NCP kW Savings	Per Unit Summer NCP kW Savings	Annual Non-elec. Savings (MMBTU)	Annual Water Savings (gal.)	Useful Life	Incremental /Full Cost	O&M Savings	Measure/End Use Description	Base Saturation	EE Saturation
11028	Dual Fuel Heat Pump (Replacing Electric Furnace)	MH	ROB	All	12,152.0	72.6%	8824.0	3.20	0.30	-9.90	0	18	$8,466.00	$0.00	Homes with Electric Furnaces and CAC	59.3%	0.0%
11029	Ductless mini-split HP (replacing ASHP)	MH	Retrofit	All	6,605.0	16.3%	1074.0	3.20	1.00	0.00	0	15	$6,564.48	$0.00	Homes with Electric Heat Pump (H&C)	8.9%	0.0%
11030	Ductless mini-split HP (replacing furnace)	MH	Retrofit	All	12,152.0	54.5%	6621.0	3.40	1.20	0.00	0	15	$11,725.48	$0.00	Homes with Electric Furnaces and CAC	59.3%	0.0%
11031	ECM Furnace Fan	MH	ROB	All	1,543.7	33.3%	514.6	0.073	0.073	0.00	0	10	$250.00	$0.00	Homes with furnaces	17.6%	25.0%
11032	Programmable Thermostat - Gas/AC	MH	Retrofit	All	2,147.0	8.4%	179.9	0.00	0.00	2.94	0	15	$35.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	17.6%	20.0%
11033	Programmable Thermostat - ASHP	MH	Retrofit	All	7,400.0	7.2%	536.0	0.00	0.00	0.00	0	15	$35.00	$0.00	Homes with Electric Heat Pump (H&C)	8.9%	20.0%
11034	Programmable Thermostat - Elec Furnace/AC	MH	Retrofit	All	12,309.0	7.1%	869.8	0.00	0.00	0.00	0	15	$35.00	$0.00	Homes with Electric Furnaces and CAC	59.3%	20.0%
11035	Smart Thermostat - Gas Heat / AC	MH	Retrofit	All	2,147.0	8.4%	179.9	0.00	0.00	2.94	0	15	$249.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	17.6%	20.0%
11036	Smart Thermostat - ASHP	MH	Retrofit	All	7,400.0	7.2%	536.0	0.00	0.00	0.00	0	15	$249.00	$0.00	Homes with Electric Heat Pump (H&C)	8.9%	20.0%
11037	Smart Thermostat - Elec Furnace/AC	MH	Retrofit	All	12,309.0	7.1%	869.8	0.00	0.00	0.00	0	15	$249.00	$0.00	Homes with Electric Furnaces and CAC	59.3%	20.0%
11038	Energy Star Room A/C	SF	NC	All	454.1	11.3%	51.4	0.113	0.113	0.00	0	9	$60.00	$0.00	Homes w/ Electric Room AC	18.7%	0.0%
11039	High Efficiency Central AC - 16 SEER	SF	NC	All	1,790.0	15.9%	284.0	0.00	0.30	0.00	0	18	$2,007.00	$0.00	Homes w/ Electric Central AC	88.2%	0.0%
11040	Ductless mini-split AC	SF	NC	All	1,790.0	43.6%	780.0	0.00	1.60	0.00	0	15	$3,306.72	$0.00	Homes w/ Electric Central AC	88.2%	0.0%
11041	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	NC	All	7,517.0	6.6%	499.0	0.00	0.20	0.00	0	18	$1,523.00	$0.00	Homes with Electric Heat Pump (H&C)	40.1%	0.0%
11042	Ground Source Heat Pump (HP Upgrade)	SF	NC	All	7,517.0	35.9%	2695.0	-1.50	-0.10	0.00	0	18	$11,772.00	$0.00	Homes with Electric Heat Pump (H&C)	40.1%	0.0%
11043	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	SF	NC	All	7,517.0	46.9%	3525.0	3.30	0.20	-10.70	0	18	$3,196.00	$0.00	Homes with Electric Heat Pump (H&C)	40.1%	0.0%
11044	Ductless mini-split HP (replacing ASHP)	SF	NC	All	7,517.0	19.1%	1434.0	3.90	1.40	0.00	0	15	$7,595.82	$0.00	Homes with Electric Furnaces and CAC	40.1%	0.0%
11045	ECM Furnace Fan	SF	NC	All	1,543.7	33.3%	514.6	0.073	0.073	0.00	0	10	$250.00	$0.00	Homes with furnaces	49.4%	0.0%
11046	Programmable Thermostat - Gas/AC	SF	NC	All	2,423.0	8.4%	204.1	0.00	0.00	3.30	0	15	$35.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	0.0%
11047	Programmable Thermostat - ASHP	SF	NC	All	7,517.0	7.3%	548.2	0.00	0.00	0.00	0	15	$35.00	$0.00	Homes with Electric Heat Pump (H&C)	24.1%	0.0%
11048	Smart Thermostat - Gas Heat / AC	SF	NC	All	2,423.0	8.4%	204.1	0.00	0.00	3.30	0	15	$249.00	$0.00	Homes w/ Electric AC Dnly (& Gas Haat)	49.4%	0.0%
11049	Smart Thermostat - ASHP	SF	NC	All	7,517.0	7.3%	548.2	0.00	0.00	0.00	0	15	$249.00	$0.00	Homes with Electric Heat Pump (H&C)	40.1%	0.0%
11050	Energy Star Room A/C	MH	NC	All	454.1	11.3%	51.4	0.113	0.113	0.00	0	9	$60.00	$0.00	Homes w/ Electric Room AC	41.6%	0.0%
11051	High Efficiency Central AC - 16 SEER	MH	NC	All	1,111.0	15.8%	176.0	0.00	0.10	0.00	0	18	$1,916.00	$0.00	Homes w/ Electric Central AC	78.4%	0.0%
11052	Ductless mini-split AC	MH	NC	All	1,111.0	31.3%	348.0	0.00	0.90	0.00	0	15	$2,480.04	$0.00	Homes w/ Electric Central AC	78.4%	0.0%
11053	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	NC	All	4,351.0	6.2%	271.0	0.00	0.10	0.00	0	18	$1,409.00	$0.00	Homes with Electric Heat Pump (H&C)	68.2%	0.0%
11054	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	MH	NC	All	4,351.0	48.7%	2119.0	2.60	0.10	-6.30	0	18	$3,082.00	$0.00	Homes with Electric Haat Pump (H&C)	68.2%	0.0%
11055	Ductless mini-split HP (replacing ASHP)	MH	NC	All	4,351.0	17.1%	744.0	3.40	0.90	0.00	0	15	$6,564.48	$0.00	Homes with Electric Furnaces and CAC	68.2%	0.0%
11056	ECM Furnace Fan	MH	NC	All	1,543.7	33.3%	514.6	0.073	0.073	0.00	0	10	$250.00	$0.00	Homes with furnaces	17.6%	0.0%
11057	Programmable Thermostat - Gas/AC	MH	NC	All	1,563.0	8.4%	130.7	0.00	0.00	1.90	0	15	$35.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	17.6%	0.0%
11058	Programmable Thermostat - ASHP	MH	NC	All	4,351.0	7.3%	318.6	0.00	0.00	0.00	0	15	$35.00	$0.00	Homes with Electric Heat Pump (H&C)	68.2%	0.0%
11059	Smart Thermostat - Gas Heat / AC	MH	NC	All	1,563.0	8.4%	130.7	0.00	0.00	1.90	0	15	$249.00	$0.00	Homes w/ Electric AC Dnly (& Gas Heat)	17.6%	0.0%
11060	Smart Thermostat - ASHP	MH	NC	All	4,351.0	7.3%	318.6	0.00	0.00	0.00	0	15	$249.00	$0.00	Homes with Electric Haat Pump (H&C)	68.2%	0.0%
12000	Other																
12001	In Home Energy Display Monitor - Gas/CAC	SF	Retrofit	All	3,323.0	5.3%	176.8	0.02	0.02	2.27	0	3	$30.00	$0.00	Homas w/ Electric AC Only (& Gas Heat)	49.4%	0.0%
12002	Home Energy Reports - Gas/CAC	SF	Retrofit	All	3,323.0	2.0%	65.0	0.01	0.01	0.84	0	1	$10.00	$0.00	Hames w/ Electric AC Only (& Gas Heat)	49.4%	0.0%
12003	In Home Energy Display Monitor - ASHP	SF	Ratrofit	All	10,369.0	5.3%	551.6	0.06	0.06	0.00	0	3	$30.00	$0.00	Homes with Electric Haat Pump (H&C)	24.1%	0.0%
12004	Home Enargy Reports - ASHP	SF	Ratrofit	All	10,369.0	2.0%	202.9	0.02	0.02	0.00	0	1	$10.00	$0.00	Homes with Electric Heat Pump (H&C)	24.1%	0.0%
12005	In Home Energy Display Monitor - Elec Furn/CAC	SF	Retrofit	All	17,045.0	5.3%	906.8	0.10	0.10	0.00	0	3	$30.00	$0.00	Homes with Electric Furnaces and CAC	16.0%	0.0%
12006	Home Energy Reports - Elec Furn/CAC	SF	Retrofit	All	17,045.0	2.0%	333.6	0.04	0.04	0.00	0	1	$10.00	$0.00	Homes with Electric Furnaces and CAC	16.0%	0.0%
12007	Two Speed Pool Pumps	SF	ROB	All	1,363.5	32.0%	436.0	0.00	1.36	0.00	0	10	$175.00	$0.00	Homes with Pools	8.7%	33.3%
1200E	Variable Speed Pool Pumps	SF	RDB	All	1,363.5	86.0%	1173.0	0.00	2.10	0.00	0	10	$750.00	$0.00	Homes with Pools	8.7%	33.3%
12009	Premium Efficiency Pool Pump Motor	SF	ROB	All	1,363.5	29.6%	404.0	0.00	0.67	0.00	0	10	$50.00	$0.00	Homes with Pools	8.7%	33.3%
12010	In Home Energy Display Monitor - Gas/CAC	MH	Retrofit	All	2,147.0	5.3%	114.2	0.01	0.01	1.55	0	3	$30.00	$0.00	Homes w/ Elactric AC Only (& Gas Heat)	17.6%	0.0%
12011	Home Energy Reports - Gas/CAC	MH	Retrofit	All	2,147.0	2.0%	42.0	0.00	0.00	0.57	0	1	$10.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	17.6%	0.0%
12012	In Home Energy Display Monitor - ASHP	MH	Retrofit	All	7,400.0	5.3%	393.7	0.04	0.04	0.00	0	3	$30.00	$0.00	Homes with Electric Heat Pump (H&C)	8.9%	0.0%
12013	Home Energy Reports - ASHP	MH	Retrofit	All	7,400.0	2.0%	144.8	0.02	0.02	0.00	0	1	$10.00	$0.00	Homes with Electric Heat Pump (H&C)	8.9%	0.0%
12014	In Home Energy Display Monitor - Elec Furn/CAC	MH	Retrofit	All	12,309.0	5.3%	654.8	0.07	0.07	0.00	0	3	$30.00	$0.00	Homes with Elactric Furnaces and CAC	59.3%	0.0%
12015	Home Energy Reports - Elec Furn/CAC	MH	Ratrofit	All	12,309.0	2.0%	240.9	0.03	0.03	0.00	0	1	$10.00	$0.00	Homes with Electric Furnaces and CAC	59.3%	0.0%
12016	In Home Energy Display Monitor - Gas/CAC	SF	NC	All	2,423.0	5.3%	128.9	0.01	0.01	2.27	0	3	$30.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	0.0%
12017	Home Enargy Reports - Gas/CAC	SF	NC	All	2,423.0	2.0%	47.4	0.01	0.01	0.84	0	1	$10.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	49.4%	0.0%
12018	In Home Energy Display Monitor - ASHP	SF	NC	All	7,517.0	5.3%	399.9	0.05	0.05	0.00	0	3	$30.00	$0.00	Homes with Electric Heat Pump (H&C)	40.1%	0.0%
12019	Home Energy Reports - ASHP	SF	NC	All	7,517.0	2.0%	147.1	0.02	0.02	0.00	0	1	$10.00	$0.00	Homes with Electric Heat Pump (H&C)	40.1%	0.0%
12020	Two Spaed Pool Pumps	SF	NC	All	1,363.5	32.0%	436.0	0.00	1.36	0.00	0	10	$175.00	$0.00	Homes with Pools	8.7%	0.0%
12021	Variable Speed Pool Pumps	SF	NC	All	1,363.5	86.0%	1173.0	0.00	2.10	0.00	0	10	$750.00	$0.00	Homes with Pools	8.7%	0.0%
12022	Premium Efficiency Pool Pump Motor	SF	NC	All	1,363.5	29.6%	404.0	0.00	0.67	0.00	0	10	$50.00	$0.00	Homes with Pools	8.7%	0.0%
12023	In Homa Enargy Display Monitor - Gas/CAC	MH	NC	All	1,563.0	5.3%	83.2	0.01	0.01	1.55	0	3	$30.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	17.6%	0.0%
12024	Home Euergy Reports - Gas/CAC	MH	NC	All	1,563.0	2.0%	30.6	0.00	0.00	0.57	0	1	$10.00	$0.00	Homes w/ Electric AC Only (& Gas Heat)	17.6%	0.0%
12025	In Home Energy Display Monitor - ASHP	MH	NC	All	4,351.0	5.3%	231.5	0.03	0.03	0.00	0	3	$30.00	$0.00	Homes with Electric Heat Pump (H&C)	68.2%	0.0%
12026	Home Energy Reports - ASHP	MH	NC	All	4,351.0	2.0%	85.1	0.01	0.01	0.00	0	1	$10.00	$0.00	Homes with Electric Heat Pump (H&C)	68.2%	0.0%
13000	Multi-Family Units																
13001	Multi-Family Homes Efficiency Kit	MF	Retrofit	All	9,460.0	4.7%	448.8	0.05	0.05	0.00	4755	8	$333.00	$7.20	All Multi-Family Homes	57.6%	31.8%
13002	Multi-Family Homes Efficiency Kit	MF	NC	All	9,460.0	4.7%	448.8	0.05	0.05	0.00	4755	8	$333.00	$7.20	All Multi-Family Homes	57.6%	0.0%
14000	New Construction Homes - Single Family																
14001	New Construction - 15% more efficient (w/AC only)	SF	NC	All	8,074.0	15.0%	1211.1	0.05	0.42	7.29	0	25	$2,124.00	$0.00	All Single Family New Homes w/ AC Only	49.4%	0.0%
14002	New Construction - 15% more efficient (w/Elec. HP)	SF	NC	All	16,653.0	15.0%	2498.0	2.22	0.41	0.00	0	25	$2,124.00	$0.00	All Single Family New Homes w/ Elec. HP	40.1%	0.0%
14003	New Construction - 15% more efficient (w/ Dual-Fuel HP (w/gas))	SP	NC	All	13,365.0	15.0%	2004.8	2.22	0.41	-12.2	0	25	$2,124.00	$0.00	All Single Family Naw Homes w/ Dual-Fuel HP (w/gas)	40.1%	0.0%
14004	New Construction - 15% more efficient (w/ Geothermal HP)	SF	NC	All	16,653.0	15.0%	2498.0	2.22	0.41	0.00	0	25	$2,124.00	$0.00	All Single Family New Homes w/ Geothermal HP	40.1%	0.0%
14005	New Construction - 30% more efficient (w/AC only)	SF	NC	All	8,074.0	30.0%	2422.2	0.05	0.42	7.29	0	25	$5,292.00	$0.00	All Single Family New Homes w/ AC Only	49.4%	0.0%
14006	New Construction - 30% more efficient (w/Elec. HP)	SF	NC	All	16,653.0	30.0%	4995.9	2.22	0.41	0.00	0	25	$5,292.00	$0.00	All Single Family New Homes w/ Elec. HP	40.1%	0.0%
14007	New Construction - 30% more efficient (w/ Dual-Fuel HP (w/gas))	SF	NC	All	13,365.0	30.0%	4009.5	2.22	0.41	-12.2	0	25	$5,292.00	$0.00	All Single Femily New Homes w/ Dual-Fuel HP (w/gas)	40.1%	0.0%
14008	New Construction - 30% more efficient (w/ Geothermal HP)	SF	NC	All	16,653.0	30.0%	4995.9	2.22	0.41	0.00	0	25	$5,292.00	$0.00	All Single Femily New Homes w/ Geothermal HP	40.1%	0.0%
14009	New Construction - 15% more efficient (w/AC only)	MH	NC	All	6,090.0	15.0%	913.5	0.03	0.24	4.20	0	25	$1,180.00	$0.00	All Single Family New Homes w/ AC Only	17.6%	0.0%
14010	New Construction - 15% more efficient (w/Elec. HP)	MH	NC	All	11,883.0	15.0%	1782.5	1.59	0.24	0.00	0	25	$1,180.00	$0.00	All Single Family New Homes w/ Elec. HP	68.2%	0.0%
14011	New Construction - 30% more efficient (w/AC only)	MH	NC	All	6,090.0	30.0%	1827.0	0.03	0.24	4.20	0	25	$2,940.00	$0.00	All Single Family Naw Homes w/ AC Only	17.6%	0.0%

Big Rivers - Residential Measure Database

Measure ID	Measure Name	Home Type (DET/ATT/MF/MF-SM/MF-MM)	ROB vs. Retrofit vs. ER vs. NC	Income Target (All / LI)	Base Elec. Use (kWh)	% Savings	Annual kWh Savings	Per Unit Winter NCP kW Savings	Per Unit Summer NCP kW Savings	Annual Non-elec. Savings (MMBTU)	Annual Water Savings (gal.)	Useful Life	Incremental /Full Cost	O&M Savings	Measure/End Use Description	Base Saturation	EE Saturation
14012	New Construction - 30% more efficient (w/Elec. HP)	MH	NC	All	11,883.0	30.0%	3564.9	1.59	0.24	0.00	0	25	$2,940.00	$0.00	All Single Family New Homes w/ Elec. HP	68.2%	0.0%
15000	Early Retirement																
15001	Energy Star Room A/C - Early Retirement	SF	ER1	All	577.9	47.0%	271.9	0.597	0.597	0.00	0	9	$128.01	$0.00	Homes w/ Electric Room AC	8.1%	23.0%
15002	Energy Star Room A/C - Early Retirement	SF	ER2	All	454.1	11.3%	51.4	0.113	0.113	0.00	0	9	$0.00	$0.00	Homes w/ Electric Room AC	8.1%	23.0%
15003	Energy Star Room A/C - Early Retiremant	SF	ER3	All	454.1	11.3%	51.4	0.113	0.113	0.00	0	9	$60.00	$0.00	Homes w/ Electric Room AC	8.1%	23.0%
15004	High Efficiency Central AC/Early Retire - 16 SEER	SF	ER1	All	2,763.0	25.8%	714.0	0.0	0.5	0.00	0	18	$2,932.60	$0.00	Homes w/ Electric Central AC	88.2%	9.0%
15005	High Efficiency Central AC/Early Retire - 16 SEER	SF	ER2	All	2,271.0	15.9%	360.0	0.0	0.3	0.00	0	18	$0.00	$0.00	Homes w/ Electric Central AC	88.2%	9.0%
15006	High Efficiency Central AC/Early Retire - 16 SEER	SF	ER3	All	2,271.0	15.9%	360.0	0.0	0.3	0.00	0	18	$2,007.00	$0.00	Homes w/ Electric Central AC	88.2%	9.0%
15007	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9.0 HSPF	SF	ER1	All	10,369.0	17.3%	1789.0	0.0	0.5	0.00	0	18	$3,296.85	$0.00	Homes with Electric Heet Pump (H&C)	24.1%	9.0%
15008	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9.0 HSPF	SF	ER2	All	9,193.0	6.7%	613.0	0.0	0.2	0.00	0	18	$0.00	$0.00	Homes with Electric Heat Pump (H&C)	24.1%	9.0%
15009	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9.0 HSPF	SF	ER3	All	9,193.0	6.7%	613.0	0.0	0.2	0.00	0	18	$1,523.00	$0.00	Homes with Electric Heat Pump (H&C)	24.1%	9.0%
15010	Ground Source Heat Pump/Early Retire (HP Upgrade)	SF	ER1	All	10,369.0	53.5%	5547.0	0.0	0.6	0.00	0	18	$13,207.64	$0.00	Homes with Electric Heat Pump (H&C)	24.1%	9.0%
15011	Ground Source Heat Pump/Early Retire (HP Upgrade)	SF	ER2	All	9,193.0	47.5%	4371.0	0.0	0.3	0.00	0	18	$0.00	$0.00	Homes with Electric Heat Pump (H&C)	24.1%	9.0%
15012	Ground Source Heat Pump/Early Retire (HP Upgrade)	SF	ER3	All	9,193.0	47.5%	4371.0	0.0	0.3	0.00	0	18	$11,772.00	$0.00	Homes with Electric Heat Pump (H&C)	24.1%	9.0%
15013	Heat Pump/Early Retire (Replacing Electric Furnace)	SF	ER1	All	17,045.0	49.7%	8465.0	0.3	0.3	0.00	0	18	$3,296.85	$0.00	Homes with Electric Furnaces and CAC	16.0%	0.0%
15014	Heat Pump/Early Retire (Replacing Electric Furnace)	SF	ER2	All	16,746.0	48.8%	8166.0	0.3	0.5	0.00	0	18	$0.00	$0.00	Homes with Electric Furnaces and CAC	16.0%	0.0%
15015	Heat Pump/Early Retire (Replacing Electric Furnace)	SF	ER3	All	16,746.0	48.8%	8166.0	0.3	0.5	0.00	0	18	$4,623.00	$0.00	Homes with Electric Furnaces and CAC	16.0%	0.0%
15016	Energy Star Room A/C - Early Retirement	MH	ER1	All	577.9	47.0%	271.9	0.597	0.597	0.00	0	9	$128.01	$0.00	Homes w/ Electric Room AC	19.7%	4.0%
15017	Energy Star Room A/C - Early Retirement	MH	ER2	All	454.1	11.3%	51.4	0.113	0.113	0.00	0	9	$0.00	$0.00	Homes w/ Electric Room AC	19.7%	4.0%
15018	Energy Star Room A/C - Early Retiremant	MH	ER3	All	454.1	11.3%	51.4	0.113	0.113	0.00	0	9	$60.00	$0.00	Homes w/ Electric Room AC	19.7%	4.0%
15019	High Efficiency Central AC/Early Retire - 16 SEER	MH	ER1	All	1,540.0	27.1%	418.0	0.00	0.30	0.00	0	18	$2,811.77	$0.00	Homes w/ Electric Central AC	78.4%	0.0%
15020	High Efficiency Central AC/Early Retire - 16 SEER	MH	ER2	All	1,790.0	15.9%	284.0	0.00	0.30	0.00	0	18	$0.00	$0.00	Homes w/ Electric Central AC	78.4%	0.0%
15021	High Efficiency Central AC/Early Retire - 16 SEER	MH	ER3	All	1,790.0	15.9%	284.0	0.00	0.30	0.00	0	18	$1,916.00	$0.00	Homes w/ Electric Central AC	78.4%	0.0%
15022	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9.0 HSPF	MH	ER1	All	7,400.0	16.4%	1214.0	0.00	0.30	0.00	0	18	$2,758.42	$0.00	Homes with Electric Heat Pump (H&C)	8.9%	0.0%
15023	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9.0 HSPF	MH	ER2	All	6,605.0	6.3%	419.0	0.00	0.10	0.00	0	18	$0.00	$0.00	Homes with Electric Heat Pump (H&C)	8.9%	0.0%
15024	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9.0 HSPF	MH	ER3	All	6,605.0	6.3%	419.0	0.00	0.10	0.00	0	18	$1,409.00	$0.00	Homes with Electric Heat Pump (H&C)	8.9%	0.0%
15025	Heat Pump/Early Retire (Replacing Electric Furnace)	MH	ER1	All	12,309.0	49.7%	6123.0	0.20	0.30	0.00	0	18	$2,758.42	$0.00	Homes with Electric Furnaces and CAC	59.3%	0.0%
15026	Heat Pump/Early Retire (Replacing Electric Furnace)	MH	ER2	All	12,152.0	49.1%	5966.0	0.20	0.20	0.00	0	18	$0.00	$0.00	Homes with Electric Furnaces and CAC	59.3%	0.0%
15027	Heat Pump/Early Retire (Replacing Electric Furnace)	MH	ER3	All	12,152.0	49.1%	5966.0	0.20	0.20	0.00	0	18	$4,287.00	$0.00	Homes with Electric Furnaces and CAC	59.3%	0.0%

Measure ID	Measure Name	Home Type	ROB vs. Retrofit vs. NC	Income Target	Base Elec. Use (kWh)	% Elec Savings	Annual Elec Savings (kWh)	Per Unit Winter NCP kW Savings	Per Unit Summer NCP kW Savings	Annual Non-elec. Savings (MMBTU)	Annual Water Savings (gal)	Useful Life	Incremental Full Cost	O&M Savings	Base Saturation	EE Saturation	Notes
1000	Appliances																
1001	Energy Star Compliant Top-Mount Refrigerator	SF	ROB	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM / GDS calc	IN TRM	BR 2013	BR 2013	Base kWh: Average of 2 top-mount configurations; kWh Savings: 10% savings; Inc. Cost: Assumes difference between CEE Tier 2 and ENERGY STAR costs to account for changing federal standard and ES spec
1002	Energy Star Compliant Side-by-Side Refrigerator	SF	ROB	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM / GDS calc	IN TRM	BR 2013	BR 2013	Base kWh: Average of 2 side-by-side configurations; kWh Savings: 10% savings; Inc. Cost: Assumes difference between CEE Tier 2 and ENERGY STAR costs to account for changing federal standard and ES spec
1003	Energy Star Compliant Chest Freezer	SF	ROB	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	BR 2013	BR 2013	kWh Savings: 10% savings
1004	Energy Star Compliant Upright Freezer (Manual Def.)	SF	ROB	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	BR 2013	BR 2013	kWh Savings: 10% savings
1005	Energy Star Dehumidifer	SF	ROB	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	RECS 2009	ES Unit Ship	
1006	Second Refrigerator Turn In	SF	Retrofit	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	GDS	EE sat: 0% b/c base consumption & savings applies to all secondary units
1007	Second Freezer Turn In	SF	Retrofit	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	GDS	EE sat: 0% b/c base consumption & savings applies to all secondary units
1008	Energy Star Compliant Top-Mount Refrigerator	MH	ROB	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM / GDS calc	IN TRM	BR 2013	BR 2013	Base kWh: Average of 2 top-mount configurations; kWh Savings: 10% savings; Inc. Cost: Assumes difference between CEE Tier 2 and ENERGY STAR costs to account for changing federal standard and ES spec
1009	Energy Star Compliant Side-by-Side Refrigerator	MH	ROB	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM / GDS calc	IN TRM	BR 2013	BR 2013	Base kWh: Average of 2 side-by-side configurations; kWh Savings: 10% savings; Inc. Cost: Assumes difference between CEE Tier 2 and ENERGY STAR costs to account for changing federal standard and ES spec
1010	Energy Star Compliant Chest Freezer	MH	ROB	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	BR 2013	BR 2013	kWh Savings: 10% savings
1011	Energy Star Compliant Upright Freezer (Manual Def.)	MH	ROB	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	BR 2013	BR 2013	kWh Savings: 10% savings
1012	Energy Star Dehumidifer	MH	ROB	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	RECS 2009	ES Unit Ship	
1013	Second Refrigerator Turn In	MH	Retrofit	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	GDS	EE sat: 0% b/c base consumption & savings applies to all secondary units
1014	Second Freezer Turn In	MN	Retrofit	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	GDS	EE sat: 0% b/c base consumption & savings applies to all secondary units
1015	Energy Star Compliant Top-Mount Refrigerator	SF	NC	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM / GDS calc	IN TRM	BR 2013	BR 2013	Base kWh: Average of 2 top-mount configurations; kWh Savings: 10% savings; Inc. Cost: Assumes difference between CEE Tier 2 and ENERGY STAR costs to account for changing federal standard and ES spec
1016	Energy Star Compliant Side-by-Side Refrigerator	SF	NC	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM / GDS calc	IN TRM	BR 2013	BR 2013	Base kWh: Average of 2 side-by-side configurations; kWh Savings: 10% savings; Inc. Cost: Assumes difference between CEE Tier 2 and ENERGY STAR costs to account for changing federal standard and ES spec
1017	Energy Star Compliant Chest Freezer	SF	NC	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	BR 2013	BR 2013	kWh Savings: 10% savings
1018	Energy Star Compliant Upright Freezer (Manual Def.)	SF	NC	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	BR 2013	BR 2013	kWh Savings: 10% savings
1019	Energy Star Dehumidifer	SF	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	RECS 2009	ES Unit Ship	
1020	Energy Star Compliant Top-Mount Refrigerator	MH	NC	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM / GDS calc	IN TRM	BR 2013	BR 2013	Base kWh: Average of 2 top-mount configurations; kWh Savings: 10% savings; Inc. Cost: Assumes difference between CEE Tier 2 and ENERGY STAR costs to account for changing federal standard and ES spec
1021	Energy Star Compliant Side-by-Side Refrigerator	MN	NC	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM / GDS calc	IN TRM	BR 2013	BR 2013	Base kWh: Average of 2 side-by-side configurations; kWh Savings: 10% savings; Inc. Cost: Assumes difference between CEE Tier 2 and ENERGY STAR costs to account for changing federal standard and ES spec
1022	Energy Star Compliant Chest Freezer	MN	NC	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	BR 2013	BR 2013	kWh Savings: 10% savings
1023	Energy Star Compliant Upright Freezer (Manual Def.)	MH	NC	-	ES Refrigerators 5.0	-	ES Refrigerators 5.0	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	BR 2013	BR 2013	kWh Savings: 10% savings
1024	Energy Star Dehumidifer	MN	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	RECS 2009	ES Unit Ship	
2000	Consumer Electronics - Single Family/Mobile Home																
2001	Efficient Televisions	SF	ROB	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	PA 2011	ES Unit Ship	Assumes 36"-39" specs
2001	Energy Star Desktop Computer	SF	ROB	-	ES Calc-Office	-	ES Calc-Office	ES Calc-Office	ES Calc-Office	GDS / IN TRM	GDS	ES Calc-Office	VT TRM	VT TRM	PA 2011	ES Unit Ship	Non-elec. Savings: Multiplies kWh savings by waste heat factor of -0.0018 (IN TRM)
2003	Energy Star Computer Monitor	SF	ROB	-	ES Calc-Office	-	ES Calc-Office	ES Calc-Office	ES Calc-Office	GDS / IN TRM	GDS	ES Calc-Office	VT TRM	VT TRM	PA 2011	ES Unit Ship	Non-elec. Savings: Multiplies kWh savings by waste heat factor of -0.0018 (IN TRM)
2004	Energy Star Laptop Computer	SF	ROB	-	ES Calc-Office	-	ES Calc-Office	ES Calc-Office	ES Calc-Office	GDS / IN TRM	GDS	ES Calc-Office	VT TRM	VT TRM	PA 2011	ES Unit Ship	Non-elec. Savings: Multiplies kWh savings by waste heat factor of -0.0018 (IN TRM); Cost: Assumes incremental cost of laptop same as desktop
2005	Smart Strip Power Strip	SF	ROB	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	RIA 2010	kWh Savings: Assumes savings from TV peripherals; Cost: Assumes 5 plug strip cost
2006	Efficient Set Top Box	SF	ROB	-	GDS	-	NJ CEP	NJ CEP	NJ CEP	NJ CEP	NJ CEP	NJ CEP	ACEEE (A041)	GDS	PA 2011	ES Unit Ship	
2007	Efficient Televisions	MH	ROB	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	PA 2011	ES Unit Ship	Assumes 36"-39" specs
2008	Energy Star Desktop Computer	MN	ROB	-	ES Calc-Office	-	ES Calc-Office	ES Calc-Office	ES Calc-Office	GDS / IN TRM	GDS	ES Calc-Office	VT TRM	VT TRM	PA 2011	ES Unit Ship	Non-elec. Savings: Multiplies kWh savings by waste heat factor of -0.0018 (IN TRM)
2009	Energy Star Computer Monitor	MN	ROB	-	ES Calc-Office	-	ES Calc-Office	ES Calc-Office	ES Calc-Office	GDS / IN TRM	GDS	ES Calc-Office	VT TRM	VT TRM	PA 2011	ES Unit Ship	Non-elec. Savings: Multiplies kWh savings by waste heat factor of -0.0018 (IN TRM)
2010	Energy Star Laptop Computer	MN	ROB	-	ES Calc-Office	-	ES Calc-Office	ES Calc-Office	ES Calc-Office	GDS / IN TRM	GDS	ES Calc-Office	VT TRM	VT TRM	PA 2011	ES Unit Ship	Non-elec. Savings: Multiplies kWh savings by waste heat factor of -0.0018 (IN TRM); Cost: Assumes incremental cost of laptop same as desktop
2011	Smart Strip Power Strip	MN	ROB	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	RIA 2010	kWh Savings: Assumes savings from TV peripherals; Cost: Assumes 5 plug strip cost
2012	Efficient Set Top Box	MH	ROB	-	GDS	-	NJ CEP	NJ CEP	NJ CEP	NJ CEP	NJ CEP	NJ CEP	ACEEE (A041)	GDS	PA 2011	ES Unit Ship	
2013	Efficient Televisions	SP	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	PA 2011	ES Unit Ship	Assumes 36"-39" specs
2014	Energy Star Desktop Computer	SF	NC	-	ES Calc-Office	-	ES Calc-Office	ES Calc-Office	ES Calc-Office	GDS / IN TRM	GDS	ES Calc-Office	VT TRM	VT TRM	PA 2011	ES Unit Ship	Non-elec. Savings: Multiplies kWh savings by waste heat factor of -0.0018 (IN TRM)
2015	Energy Star Computer Monitor	SF	NC	-	ES Calc-Office	-	ES Calc-Office	ES Calc-Office	ES Calc-Office	GDS / IN TRM	GDS	ES Calc-Office	VT TRM	VT TRM	PA 2011	ES Unit Ship	Non-elec. Savings: Multiplies kWh savings by waste heat factor of -0.0018 (IN TRM)
2016	Energy Star Laptop Computer	SF	NC	-	ES Calc-Office	-	ES Calc-Office	ES Calc-Office	ES Calc-Office	GDS / IN TRM	GDS	ES Calc-Office	VT TRM	VT TRM	PA 2011	ES Unit Ship	Non-elec. Savings: Multiplies kWh savings by waste heat factor of -0.0018 (IN TRM); Cost: Assumes incremental cost of laptop same as desktop

Measure ID	Measure Name	Home Type (DET, ATT, MF, MH, SM MF, MM)	ROB vs. Retrofit vs. NC	Income Target	Base Elec. Use (kWh)	% Elec. Savings	Annual Elec. Savings (kWh)	Per Unit Winter NCP kW Savings	Per Unit Summer NCP kW Savings	Annual Non-elec Savings (MMBTU)	Annual Water Savings (gal)	Useful Life	Incremental Full Cost	O&M Savings	Base Saturation	EE Saturation	Notes
2017	Smart Strip Power Strip	SF	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	RIA 2010	kWh Savings: Assumes savings from TV peripherals; Cost: Assumes 5 plug strip cost
2018	Efficient Set Top Box	SF	NC	-	GDS	-	NI CEP	NI CEP	NI CEP	NI CEP	NI CEP	NI CEP	ACEEE (A041)	GDS	PA 2011	ES Unit Ship	
2019	Efficient Televisions	MH	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	PA 2011	ES Unit Ship	Assumes 36"-39" specs
2020	Energy Star Desktop Computer	MH	NC	-	ES Calc-Office	-	ES Calc-Office	ES Calc-Office	ES Calc-Office	GDS / IN TRM	GDS	ES Calc-Office	VT TRM	VT TRM	PA 2011	ES Unit Ship	Non-elec. Savings: Multiplies kWh savings by waste heat factor of -0.0018 (IN TRM)
2021	Energy Star Computer Monitor	MH	NC	-	ES Calc-Office	-	ES Calc-Office	ES Calc-Office	ES Calc-Office	GDS / IN TRM	GDS	ES Calc-Office	VT TRM	VT TRM	PA 2011	ES Unit Ship	Non-elec. Savings: Multiplies kWh savings by waste heat factor of -0.0018 (IN TRM)
2022	Energy Star Laptop Computer	MH	NC	-	ES Calc-Office	-	ES Calc-Office	ES Calc-Office	ES Calc-Office	GDS / IN TRM	GDS	ES Calc-Office	VT TRM	VT TRM	PA 2011	ES Unit Ship	Non-elec. Savings: Multiplies kWh savings by waste heat factor of -0.0018 (IN TRM); Cost: Assumes incremental cost of laptop same as desktop
2023	Smart Strip Power Strip	MH	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	RIA 2010	kWh Savings: Assumes savings from TV peripherals; Cost: Assumes 5 plug strip cost
2024	Efficient Set Top Box	MH	NC	-	GDS	-	NI CEP	NI CEP	NI CEP	NI CEP	NI CEP	NI CEP	ACEEE (A041)	GDS	PA 2011	ES Unit Ship	
3000	Lighting - Single Family /Mobile Home																
3001	Standard CFL - Average Use (3 hours/day)	SF	ROB	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM	IN TRM	IN TRM	GDS calc	BR 2013 / US DOE	BR 2013	Savings: Assumes delta watts multiplier of 2.0; assumes 14 W CFL average; O&M Savings: GDS calculation using IN TRM estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012
3002	Standard LED - Average Use (3 hours/day)	SF	ROB	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM	IN TRM	NEEP RLS	GDS calc	BR 2013 / US DOE	BR 2013	O&M Savings: GDS calculation using IN TRM estimate of useful life and assumed $1 baseline cost per NEEP RLS 2
3003	Specialty CFL	SF	ROB	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	GDS	NEEP RLS	NEEP RLS	GDS/NEEP RLS	BR 2013	BR 2013 / US DOE	O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEE
3004	Specialty LED	SF	ROB	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	GDS	NEEP RLS	IN TRM	GDS/NEEP RLS	BR 2013	BR 2013 / US DOE	O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEE
3005	Energy Star Torchiere	SF	ROB	-	GDS Calc / NMR	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	GDS/IN TRM	MA Baseline 2009	BR 2013	Base kWh: Adds delta watts (115.8) to average post-wattage observed (62.7) by NMR report; O&M Savings: GDS calculation using IN TRM estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012; Base saturation: Assumes 0.8 halogen torchieres per SF home;
3006	LED Nightlight	SF	ROB	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	GDS/IN TRM	GDS	GDS	O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEE
3007	Exterior CFL Fixture	SF	ROB	-	Mid-Atl TRM	-	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	GDS/ILL TRM	PA 2011	BR 2013	Useful life: 20 years for measure level screening per Ill TRM; O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012
3008	Exterior LED Fixture	SF	ROB	-	Mid-Atl TRM	-	GDS/IN TRM	GDS/IN TRM	GDS/IN TRM	Ill TRM	Ill TRM	NEEP RLS	MEMD	GDS/NEEP RLS	PA 2011	BR 2013	Useful life: Assumed to be same as specialty LED bulbs; O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012
3009	Standard CFL - Average Use (3 hours/day)	MH	ROB	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM	IN TRM	IN TRM	GDS calc	BR 2013 / US DOE	BR 2013	Savings: Assumes delta watts multiplier of 2.0; assumes 14 W CFL average; O&M Savings: GDS calculation using IN TRM estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012
3010	Standard LED - Average Use (3 hours/day)	MH	ROB	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM	IN TRM	NEEP RLS	GDS calc	BR 2013 / US DOE	BR 2013	O&M Savings: GDS calculation using IN TRM estimate of useful life and assumed $1 baseline cost per NEEP RLS 2
3011	Specialty CFL	MH	ROB	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	GDS	NEEP RLS	NEEP RLS	GDS/NEEP RLS	BR 2013	BR 2013 / US DOE	O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEE
3012	Specialty LED	MH	ROB	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	GDS	NEEP RLS	IN TRM	GDS/NEEP RLS	BR 2013	BR 2013 / US DOE	O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEE
3013	Energy Star Torchiere	MH	ROB	-	GDS Calc / NMR	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	GDS/IN TRM	MA Baseline 2009	BR 2013	Base kWh: Adds delta watts (115.8) to average post-wattage observed (62.7) by NMR report; O&M Savings: GDS calculation using IN TRM estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012; Base saturation: Assumes 0.8 halogen torchieres per SF home;
3014	LED Nightlight	MH	ROB	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	GDS/IN TRM	GDS	GDS	O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEE
3015	Exterior CFL Fixture	MH	ROB	-	Mid-Atl TRM	-	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	GDS/ILL TRM	PA 2011	BR 2013	Useful life: 20 years for measure level screening per Ill TRM; O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012
3016	Exterior LED Fixture	MH	ROB	-	Mid-Atl TRM	-	GDS/IN TRM	GDS/IN TRM	GDS/IN TRM	Ill TRM	Ill TRM	NEEP RLS	MEMD	GDS/NEEP RLS	PA 2011	BR 2013	Useful life: Assumed to be same as specialty LED bulbs; O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012
3017	Standard CFL - Average Use (3 hours/day)	SF	NC	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM	IN TRM	IN TRM	GDS calc	BR 2013 / US DOE	BR 2013	Savings: Assumes delta watts multiplier of 2.0; assumes 14 W CFL average; O&M Savings: GDS calculation using IN TRM estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012
3018	Standard LED - Average Use (3 hours/day)	SF	NC	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM	IN TRM	NEEP RLS	GDS calc	BR 2013 / US DOE	BR 2013	O&M Savings: GDS calculation using IN TRM estimate of useful life and assumed $1 baseline cost per NEEP RLS 2
3019	Specialty CFL	SF	NC	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	GDS	NEEP RLS	NEEP RLS	GDS/NEEP RLS	BR 2013	BR 2013 / US DOE	O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEE
3020	Specialty LED	SF	NC	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	GDS	NEEP RLS	IN TRM	GDS/NEEP RLS	BR 2013	BR 2013 / US DOE	O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEE
3021	Energy Star Torchiere	SF	NC	-	GDS Calc / NMR	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	GDS/IN TRM	MA Baseline 2009	BR 2013	Base kWh: Adds delta watts (115.8) to average post-wattage observed (62.7) by NMR report; O&M Savings: GDS calculation using IN TRM estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012; Base saturation: Assumes 0.8 halogen torchieres per SF home;
3022	LED Nightlight	SF	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	GDS/IN TRM	GDS	GDS	O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEE
3023	Exterior CFL Fixture	SF	NC	-	Mid-Atl TRM	-	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	GDS/ILL TRM	PA 2011	BR 2013	Useful life: 20 years for measure level screening per Ill TRM; O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012
3024	Exterior LED Fixture	SF	NC	-	Mid-Atl TRM	-	GDS/IN TRM	GDS/IN TRM	GDS/IN TRM	Ill TRM	Ill TRM	NEEP RLS	MEMD	GDS/NEEP RLS	PA 2011	BR 2013	Useful life: Assumed to be same as specialty LED bulbs; O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012
3025	Standard CFL - Average Use (3 hours/day)	MH	NC	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM	IN TRM	IN TRM	GDS calc	BR 2013 / US DOE	BR 2013	Savings: Assumes delta watts multiplier of 2.0; assumes 14 W CFL average; O&M Savings: GDS calculation using IN TRM estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012
3026	Standard LED - Average Use (3 hours/day)	MH	NC	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM	IN TRM	NEEP RLS	GDS calc	BR 2013 / US DOE	BR 2013	O&M Savings: GDS calculation using IN TRM estimate of useful life and assumed $1 baseline cost per NEEP RLS 2
3027	Specialty CFL	MH	NC	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	GDS	NEEP RLS	NEEP RLS	GDS/NEEP RLS	BR 2013	BR 2013 / US DOE	O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEE
3028	Specialty LED	MH	NC	-	IN TRM / GDS calc	-	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	IN TRM / GDS calc	GDS	NEEP RLS	IN TRM	GDS/NEEP RLS	BR 2013	BR 2013 / US DOE	O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEE
3029	Energy Star Torchiere	MH	NC	-	GDS Calc / NMR	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	GDS/IN TRM	MA Baseline 2009	BR 2013	Base kWh: Adds delta watts (115.8) to average post-wattage observed (62.7) by NMR report; O&M Savings: GDS calculation using IN TRM estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012; Base saturation: Assumes 0.8 halogen torchieres per SF home;
3030	LED Nightlight	MH	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	GDS/IN TRM	GDS	GDS	O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEE
3031	Exterior CFL Fixture	MH	NC	-	Mid-Atl TRM	-	Mid-Atl TRM	Mid-Atl TRM	Mid-Atl TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	GDS/ILL TRM	PA 2011	BR 2013	Useful life: 20 years for measure level screening per Ill TRM; O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012

Big Rivers - Residential Measure Database - Sources

Measure ID	Measure Name	Home Type	ROB vs. Retrofit vs. NC	Income Target	Base Elec. Use (kWh)	% Elec. Savings	Annual Elec. Savings (kWh)	Per Unit Winter NCP kW Savings	Per Unit Summer NCP kW Savings	Annual Non-elec. Savings (MMBTU)	Annual Water Savings (gal.)	Useful Life	Incremental /Full Cost	O&M Savings	Base Saturation	EE Saturation	Notes
3032	Exterior LED Fixture	MH	NC	-	Mid-Atl TRM	-	GDS/IN TRM	GDS/IN TRM	GDS/IN TRM	IO TRM	III TRM	NEEP RLS	MEMO	GDS/NEEP RLS	PA 2011	BR 2013	Useful life: Assumed to be same as specialty LED bulbs; O&M Savings: GDS calculation using NEEP RLS 2012 estimate of useful life and assumed $1 baseline cost per NEEP RLS 2012
4000	Electric Water Heating - Single Family/Mobile Homes																
4001	Low Flow Faucet Aerators	SF	Retrofit	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	III TRM	IN TRM	BR 2013 / Mid-Atl TRM	PA 2011	Base kWh: Assumes 1/3 of aerators installed in kitchens; 2/3 of aerators installed in bathrooms kWh/kW/Water Savings: Assumes 1/3 of aerators installed in kitchens; 2/3 of aerators installed in bathrooms; Cost: Full cost of installation (parts & labor); Base saturation: % of homes with electric water heating * 3.5 faucet aerators per home
4002	Low Flow Showerhead	SF	Retrofit	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	III TRM	IN TRM	BR 2013 / Mid-Atl TRM	PA 2011	Cost: Full cost of installation (parts & labor); Base saturation: % of homes with electric water heating * 1.6 showerheads per home
4003	Water Heater Blanket	SF	Retrofit	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	PA 2011	
4004	Water Heater Pipe Wrap	SF	Retrofit	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	PA 2011	Cost: Assumes 5 linear feet at $3/LF
4005	Heat Pump Water Heater (resistance heat)	SF	ROB	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IH TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	NEEP HPWH	
4006	Heat Pump Water Heater (ASHP heat)	SF	ROB	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	NEEP HPWH	
4007	Solar Water Heating	SF	Retrofit	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	NEEP HPWH	
4008	Energy Star Dishwasher (Electric Water Heating)	SF	ROB	-	ES App Calc	-	ES App Calc	ES App Calc	ES App Calc	GDS	ES App Calc	IN TRM	ES App Calc	IN TRM	BR 2013	BR 2013	Base kWh: Based on updated federal standard (2012-05-30 Energy Conservation Program: Energy Conservation Standards for Residential Dishwashers; Direct final rule); kWh Savings: Based on Draft 2 Version 5.0 specs
4009	Energy Star Dishwasher (Non-Electric WH)	SF	ROB	-	ES App Calc	-	ES App Calc	ES App Calc	ES App Calc	ES App Calc	ES App Calc	IN TRM	ES App Calc	IN TRM	BR 2013	BR 2013	Base kWh: Based on updated federal standard (2012-05-30 Energy Conservation Program: Energy Conservation Standards for Residential Dishwashers; Direct final rule); kWh Savings: Based on Draft 2 Version 5.0 specs
4010	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	ROB	-	GDS	-	ES 7.0 / GDS calc	ES 7.0 / IN TRM	ES 7.0 / IN TRM	GDS	ES 7.0	IN TRM	GDS / IN TRM	IN TRM	BR 2013	BR 2013	kWh Savings: GDS calculation based on draft ENERGY STAR 7.0 clothes washer specs; Cost: GDS estimate = half of IN TRM value to account for decreased savings with implementation of 2015 federal standard
4011	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	SF	ROB	-	GDS	-	ES 7.0 / GDS calc	ES 7.0 / IN TRM	ES 7.0 / IN TRM	ES 7.0 / GDS calc	ES 7.0	IN TRM	GDS / IN TRM	IN TRM	BR 2013	BR 2013	kWh Savings: GDS calculation based on draft ENERGY STAR 7.0 clothes washer specs; Cost: GDS estimate = half of IN TRM value to account for decreased savings with implementation of 2015 federal standard
4012	Low Flow Faucet Aerators	MH	Retrofit	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IO TRM	IN TRM	BR 2013 / Mid-Atl TRM	PA 2011	Base kWh: Assumes 1/3 of aerators installed in kitchens; 2/3 of aerators installed in bathrooms kWh/kW/Water Savings: Assumes 1/3 of aerators installed in kitchens; 2/3 of aerators installed in bathrooms; Cost: Full cost of installation (parts & labor); Base saturation: % of homes with electric water heating * 3.5 faucet aerators per home
4013	Low Flow Showerhead	MH	Retrofit	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	III TRM	IN TRM	BR 2013 / Mid-Atl TRM	PA 2011	Cost: Full cost of installation (parts & labor); Base saturation: % of homes with electric water heating * 1.6 showerheads per home
4014	Water Heater Blanket	MH	Retrofit	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	PA 2011	
4015	Water Heater Pipe Wrap	MH	Retrofit	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	PA 2011	Cost: Assumes 5 linear feet at $3/LF
4016	Energy Star Dishwasher (Electric Water Heating)	MH	ROB	-	ES App Calc	-	ES App Calc	ES App Calc	ES App Calc	GDS	ES App Calc	IN TRM	ES App Calc	IN TRM	BR 2013	BR 2013	Base kWh: Based on updated federal standard (2012-05-30 Energy Conservation Program: Energy Conservation Standards for Residential Dishwashers; Direct final rule); kWh Savings: Based on Draft 2 Version 5.0 specs
4017	Energy Star Dishwasher (Non-Electric WH)	MH	ROB	-	ES App Calc	-	ES App Calc	ES App Calc	ES App Calc	ES App Calc	ES App Calc	IN TRM	ES App Calc	IN TRM	BR 2013	BR 2013	Base kWh: Based on updated federal standard (2012-05-30 Energy Conservation Program: Energy Conservation Standards for Residential Dishwashers; Direct final rule); kWh Savings: Based on Draft 2 Version 5.0 specs
4018	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	ROB	-	GDS	-	ES 7.0 / GDS calc	ES 7.0 / IN TRM	ES 7.0 / IN TRM	ES 7.0 / GDS calc	ES 7.0	IN TRM	GDS / IN TRM	IN TRM	BR 2013	BR 2013	kWh Savings: GDS calculation based on draft ENERGY STAR 7.0 clothes washer specs; Cost: GDS estimate = half of IN TRM value to account for decreased savings with implementation of 2015 federal standard
4019	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	MH	ROB	-	GDS	-	ES 7.0 / GDS calc	ES 7.0 / IN TRM	ES 7.0 / IN TRM	ES 7.0 / GDS calc	ES 7.0	IN TRM	GDS / IN TRM	IN TRM	BR 2013	BR 2013	kWh Savings: GDS calculation based on draft ENERGY STAR 7.0 clothes washer specs; Cost: GDS estimate = half of IN TRM value to account for decreased savings with implementation of 2015 federal standard
4020	Low Flow Faucet Aerators	SF	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	III TRM	IN TRM	BR 2013 / Mid-Atl TRM	PA 2011	Base kWh: Assumes 1/3 of aerators installed in kitchens; 2/3 of aerators installed in bathrooms kWh/kW/Water Savings: Assumes 1/3 of aerators installed in kitchens; 2/3 of aerators installed in bathrooms; Cost: Full cost of installation (parts & labor); Base saturation: % of homes with electric water heating * 3.5 faucet aerators per home
4021	Low Flow Showerhead	SF	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	III TRM	IN TRM	BR 2013 / Mid-Atl TRM	PA 2011	Cost: Full cost of installation (parts & labor); Base saturation: % of homes with electric water heating * 1.6 showerheads per home
4022	Water Heater Blanket	SF	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	PA 2011	
4023	Water Heater Pipe Wrap	SF	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	PA 2011	Cost: Assumes 5 linear feet at $3/LF
4024	Heat Pump Water Heater (ASHP heat)	SF	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	NEEP HPWH	
4025	Solar Water Heating	SF	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	NEEP HPWH	
4026	Energy Star Dishwasher (Electric Water Heating)	SF	NC	-	ES App Calc	-	ES App Calc	ES App Calc	ES App Calc	GDS	ES App Calc	IN TRM	ES App Calc	IN TRM	BR 2013	BR 2013	Base kWh: Based on updated federal standard (2012-05-30 Energy Conservation Program: Energy Conservation Standards for Residential Dishwashers; Direct final rule); kWh Savings: Based on Draft 2 Version 5.0 specs
4027	Energy Star Dishwasher (Non-Electric WH)	SF	NC	-	ES App Calc	-	ES App Calc	ES App Calc	ES App Calc	ES App Calc	ES App Calc	IN TRM	ES App Calc	IN TRM	BR 2013	BR 2013	Base kWh: Based on updated federal standard (2012-05-30 Energy Conservation Program: Energy Conservation Standards for Residential Dishwashers; Direct final rule); kWh Savings: Based on Draft 2 Version 5.0 specs
4028	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	NC	-	GDS	-	ES 7.0 / GDS calc	ES 7.0 / IN TRM	ES 7.0 / IN TRM	ES 7.0 / GDS calc	ES 7.0	IN TRM	GDS / IN TRM	IN TRM	BR 2013	BR 2013	kWh Savings: GDS calculation based on draft ENERGY STAR 7.0 clothes washer specs; Cost: GDS estimate = half of IN TRM value to account for decreased savings with implementation of 2015 federal standard
4029	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	SF	NC	-	GDS	-	ES 7.0 / GDS calc	ES 7.0 / IN TRM	ES 7.0 / IN TRM	ES 7.0 / GDS calc	ES 7.0	IN TRM	GDS / IN TRM	IN TRM	BR 2013	BR 2013	kWh Savings: GDS calculation based on draft ENERGY STAR 7.0 clothes washer specs; Cost: GDS estimate = half of IN TRM value to account for decreased savings with implementation of 2015 federal standard
4030	Low Flow Faucet Aerators	MH	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IH TRM	IN TRM	IN TRM	III TRM	IN TRM	BR 2013 / Mid-Atl TRM	PA 2011	Base kWh: Assumes 1/3 of aerators installed in kitchens; 2/3 of aerators installed in bathrooms kWh/kW/Water Savings: Assumes 1/3 of aerators installed in kitchens; 2/3 of aerators installed in bathrooms; Cost: Full cost of installation (parts & labor); Base saturation: % of homes with electric water heating * 3.5 faucet aerators per home
4031	Low Flow Showerhead	MH	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	III TRM	IN TRM	BR 2013 / Mid-Atl TRM	PA 2011	Cost: Full cost of installation (parts & labor); Base saturation: % of homes with electric water heating * 1.6 showerheads per home
4032	Water Heater Blanket	MH	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	PA 2011	
4033	Water Heater Pipe Wrap	MH	NC	-	IN TRM	-	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	PA 2011	Cost: Assumes 5 linear feet at $3/LF
4034	Energy Star Dishwasher (Electric Water Heating)	MH	NC	-	ES App Calc	-	ES App Calc	ES App Calc	ES App Calc	GDS	ES App Calc	IN TRM	ES App Calc	IN TRM	BR 2013	BR 2013	Base kWh: Based on updated federal standard (2012-05-30 Energy Conservation Program: Energy Conservation Standards for Residential Dishwashers; Direct final rule); kWh Savings: Based on Draft 2 Version 5.0 specs
4035	Energy Star Dishwasher (Non-Electric WH)	MH	NC	-	ES App Calc	-	ES App Calc	ES App Calc	ES App Calc	ES App Calc	ES App Calc	IN TRM	ES App Calc	IN TRM	BR 2013	BR 2013	Base kWh: Based on updated federal standard (2012-05-30 Energy Conservation Program: Energy Conservation Standards for Residential Dishwashers; Direct final rule); kWh Savings: Based on Draft 2 Version 5.0 specs
4036	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	NC	-	GDS	-	ES 7.0 / GDS calc	ES 7.0 / IN TRM	ES 7.0 / IN TRM	ES 7.0 / GDS calc	ES 7.0	IN TRM	GDS / IN TRM	IN TRM	BR 2013	BR 2013	kWh Savings: GDS calculation based on draft ENERGY STAR 7.0 clothes washer specs; Cost: GDS estimate = half of IN TRM value to account for decreased savings with implementation of 2015 federal standard
4037	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	MH	NC	-	GDS	-	ES 7.0 / GDS calc	ES 7.0 / IN TRM	ES 7.0 / IN TRM	ES 7.0 / GDS calc	ES 7.0	IN TRM	GDS / IN TRM	IN TRM	BR 2013	BR 2013	kWh Savings: GDS calculation based on draft ENERGY STAR 7.0 clothes washer specs; Cost: GDS estimate = half of IN TRM value to account for decreased savings with implementation of 2015 federal standard

Big Rivers - Residential Measure Database - Sources

Measure ID	Measure Name	Home Type (DET, ATT, MF, MH, SM, MF, MM)	ROB vs. Retrofit vs. NC	Income Target	Base Elec Use (kWh)	% Elec Savings	Annual Elec Savings (kWh)	Per Unit Winter NCP kW Savings	Per Unit Summer NCP kW Savings	Annual Non-elec Savings (MMBTU)	Annual Water Savings (gal)	Useful Life	Incremental Full Cost	O&M Savings	Base Saturation	EE Saturation	Notes
5000	Space Heating and Space Cooling Shell Measures - Single Family Homes w/ Electric AC Only (& Gas Heat)																
5001	Insulation - Ceiling (R-0 to R-19)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
5002	Insulation - Floor (R-0 to R-19)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
5003	Energy Star Windows	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	RECS 2009	
5004	Insulation -Ceiling (R-19 to R-38)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
5005	Insulation -Ceiling (R-0 to R-38)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
5006	Insulation -Ceiling (R-9 to R-38)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
5007	Insulation -Ceiling (R-11 to R-38)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
5008	Air Sealing	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
5009	Duct Sealing	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
5010	Radiant Barriers	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	GDS	ARK TRM	ES Savings & Cost	GDS	BR 2013	GDS	
5011	Complete Weatherization Package	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	GDS calc	IN TRM	BR 2013	RECS 2009	Useful Life: 13 years is roughly the average of the measures in the package; Cost: Cost includes 20 CFL bulbs, low flow showerheads and faucet aerators, duct sealing, air sealing, diagnostic fee and initial site visit cost
5012	Energy Star Windows	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	GDS	
5013	Insulation -Ceiling (R-38 Grade 2 to Grade 1)	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	ES Savings & Cost	IN TRM	BR 2013	GDS	
5014	Air Sealing	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	ES Savings & Cost	IN TRM	BR 2013	GDS	
5015	Duct Sealing	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	ES Savings & Cost	IN TRM	BR 2013	GDS	
5016	Radiant Barriers	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	GDS	ARK TRM	ES Savings & Cost	GDS	BR 2013	GDS	
6000	Space Heating and Space Cooling Shell Measures - Single Family Homes w/ Electric Heat Pump																
6001	Insulation - Ceiling (R-0 to R-19)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
6002	Insulation - Floor (R-0 to R-19)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
6003	Energy Star Windows	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	RECS 2009	
6004	Insulation -Ceiling (R-19 to R-38)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
6005	Insulation -Ceiling (R-0 to R-38)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
6006	Insulation -Ceiling (R-9 to R-38)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
6007	Insulation -Ceiling (R-11 to R-38)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
6008	Air Sealing	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	GDS	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
6009	Duct Sealing	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
6010	Radiant Barriers	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	GDS	ARK TRM	ES Savings & Cost	GDS	BR 2013	GDS	
6011	Complete Weatherization Package	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	GDS calc	IN TRM	BR 2013	RECS 2009	Useful Life: 13 years is roughly the average of the measures in the package; Cost: Cost includes 20 CFL bulbs, ceiling insulation (R9-R38), low flow showerheads and faucet aerators, duct sealing, air sealing, diagnostic fee and initial site visit cost
6012	Energy Star Windows	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	GDS	
6013	Insulation -Ceiling (R-38 Grade 2 to Grade 1)	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	ES Savings & Cost	IN TRM	BR 2013	GDS	
6014	Air Sealing	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	GDS	IN TRM	ES Savings & Cost	IN TRM	BR 2013	GDS	
6015	Duct Sealing	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	ES Savings & Cost	IN TRM	BR 2013	GDS	
6016	Radiant Barriers	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	GDS	ARK TRM	ES Savings & Cost	GDS	BR 2013	GDS	
7000	Space Heating and Space Cooling Shell Measures - Single Family Homes w/ Electric Furnace																
7001	Insulation - Ceiling (R-0 to R-19)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
7002	Insulation - Floor (R-0 to R-19)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
7003	Energy Star Windows	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	RECS 2009	
7004	Insulation -Ceiling (R-19 to R-38)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
7005	Insulation -Ceiling (R-0 to R-38)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
7006	Insulation -Ceiling (R-9 to R-38)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
7007	Insulation -Ceiling (R-11 to R-38)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
7008	Air Sealing	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	GDS	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
7009	Duct Sealing	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
7010	Radiant Barriers	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	GDS	ARK TRM	ES Savings & Cost	GDS	BR 2013	GDS	
7011	Complete Weatherization Package	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	GDS calc	IN TRM	BR 2013	RECS 2009	Useful Life: 13 years is roughly the average of the measures in the package; Cost: Cost includes 20 CFL bulbs, ceiling insulation (R9-R38), low flow showerheads and faucet aerators, duct sealing, air sealing, diagnostic fee and initial site visit cost
8000	Space Heating and Space Cooling Shell Measures - Mobile Homes w/ Electric AC Only (& Gas Heat)																
8001	Air Sealing	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
8002	Insulation - Floor (R-11 to R-30)	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
8003	Energy Star Windows	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	RECS 2009	
8004	Duct Sealing	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
8005	Complete Weatherization Package	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	GDS calc	IN TRM	BR 2013	RECS 2009	Useful Life: 13 years is roughly the average of the measures in the package; Cost: Cost includes 20 CFL bulbs, floor insulation, low flow showerheads and faucet aerators, duct sealing, air sealing, diagnostic fee and initial site visit cost
8006	Air Sealing	MH	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	ES Savings & Cost	IN TRM	BR 2813	GDS	
8007	Insulation - Floor (R-19 to R-30)	MH	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	ES Savings & Cost	IN TRM	BR 2013	GDS	
8008	Energy Star Windows	MH	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	GDS	
8009	Duct Sealing	MH	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	ES Savings & Cost	IN TRM	BR 2013	GDS	
9000	Space Heating and Space Cooling Shell Measures - Mobile Homes w/ Electric Heat Pump																
9001	Air Sealing	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	GDS	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
9002	Insulation - Floor (R-11 to R-30)	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
9003	Energy Star Windows	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	RECS 2009	
9004	Duct Sealing	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
9005	Complete Weatherization Package	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	GDS calc	IN TRM	BR 2013	RECS 2009	Useful Life: 13 years is roughly the average of the measures in the package; Cost: Cost includes 20 CFL bulbs, floor insulation, low flow showerheads and faucet aerators, duct sealing, air sealing, diagnostic fee and initial site visit cost
9006	Air Sealing	MH	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	GDS	IN TRM	ES Savings & Cost	IN TRM	BR 2013	GDS	
9007	Insulation - Floor (R-19 to R-30)	MH	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	ES Savings & Cost	IN TRM	BR 2013	GDS	
9008	Energy Star Windows	MH	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	GDS	
9009	Duct Sealing	MH	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	ES Savings & Cost	IN TRM	BR 2013	GDS	

Measure ID	Measure Name	Home Type (DET, ATT, MF, MH, SW, MF, MH)	ROB vs. Retrofit vs. NC	Income Target	Base Elec Use (kWh)	% Elec Savings	Annual Elec Savings (kWh)	Per Unit Winter NCP kW Savings	Per Unit Summer NCP kW Savings	Annual Non-elec Savings (MMBTU)	Annual Water Savings (gal.)	Useful Life	Incremental /Full Cost	O&M Savings	Base Saturation	EE Saturation	Notes
10000	Space Heating and Space Cooling Shell Measures - Mobile Homes w/ Electric Heat																
10001	Air Sealing	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	GDS	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
10002	Insulation - Floor (R-11 to R-30)	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
10003	Energy Star Windows	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	Mid-Atl TRM	IN TRM	BR 2013	RECS 2009	
10004	Duct Sealing	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	RECS 2009	
10005	Complete Weatherization Package	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	GDS calc	IN TRM	BR 2013	RECS 2009	Useful Life: 13 years is roughly the average of the measures in the package; Cost: Cost includes 20 CFL bulbs, floor insulation, low flow showerheads and faucet aerators, duct sealing, air sealing, diagnostic fee and initial site visit cost
11000	Space Heating and Space Cooling Equipment - Single Family/Mobile Homes																
11001	HVAC Tune-Up (Central AC)	SF	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	Cost: Assumes cost of inspection and tune-up
11002	HVAC Tune-Up (Heat Pump)	SF	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM / REM Rate	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	Winter kW: Assumes REM/Rate heating savings (furnace fan) across 982 full load heating hours per IN TRM for Evansville, IN Cost: Assumes cost of inspection and tune-up
11003	Energy Star Room A/C	SF	ROB	-	GDS/IN TRM	-	GDS/IN TRM	GDS/IN TRM	GDS/IN TRM	IN TRM	IN TRM	Mid Atl TRM	Mid Atl TRM	IN TRM	BR 2013	PA 2011	Consumption: Assumes federal standard 9.8 EER; Savings: Assumes full load hours of Ft. Wayne (closest to Big Rivers territory from IN TRM) - average of ENERGY STAR unit and CEE Tier 2 EER efficiencies (11.05 EER = (10.8+11.3)/2); Cost: Average of CEE Tier 2 and ENERGY STAR incremental costs
11004	High Efficiency Central AC - 16 SEER	SF	ROB	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	
11005	Ductless mini-split AC	SF	ROB	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	PA TRM	NEEP ICS / GDS	IN TRM	BR 2013	PA 2011	Cost: GDS calculation using NEEP ICS to estimate ductless minisplit AC full cost and then subtracted full cost of ce
11006	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	ROB	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	
11007	Ground Source Heat Pump (HP Upgrade)	SF	ROB	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	CenterPoint	IN TRM	BR 2013	PA 2011	Cost: Full cost of 4 ton GSHP ($17,500 per CenterPoint) minus full cost of 4 ton ASHP ($5,728 per NEEP ICS)
11008	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	SF	ROB	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	GDS	
11009	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	SF	ROB	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS / GDS	IN TRM	BR 2013	PA 2011	Useful Life: Assumed same as ASHP; Cost: Assumes incremental cost of efficient ASHP ($1,523 per NEEP ICS) + cost of baseline furnace ($1,673 per NEEP ICS)
11010	Dual Fuel Heat Pump (Replacing Electric Furnace)	SF	ROB	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS / GDS	IN TRM	BR 2013	GDS	Useful Life: Assumed same as ASHP; Cost: Assumes full cost of efficient ASHP ($7,252 per NEEP ICS) + cost of baseline furnace ($1,673 per NEEP ICS)
11011	Ductless mini-split HP (replacing ASHP)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	PA TRM	NEEP ICS / GDS	IN TRM	BR 2013	PA 2011	Cost: GDS interpolation of NEEP ICS data to estimate cost of two 2-ton units
11012	Ductless mini-split HP (replacing furnace)	SF	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	PA TRM	NEEP ICS / GDS	IN TRM	BR 2013	GDS	Cost: Assumes full cost of two 2-ton ductless minisplit systems + cost of 4-ton ASHP (14 SEER) back-up system
11013	ECM Furnace Fan	SF	ROB	-	GDS	-	Mid-Atl TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	GDS	Savings: Mid-Atl TRM estimates adjusted for estimated KY heating & cooling degree days
11014	Programmable Thermostat - Gas/AC	SF	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	IN TRM / REM Rate	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
11015	Programmable Thermostat - ASHP	SF	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
11016	Programmable Thermostat - Elec Furnace/AC	SF	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
11017	Smart Thermostat - Gas Heat / AC	SF	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	IN TRM / REM Rate	IN TRM	IN TRM	NEST website	IN TRM	BR 2013	RECS 2009	
11018	Smart Thermostat - ASHP	SF	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	GDS	IN TRM	IN TRM	NEST website	IN TRM	BR 2013	RECS 2009	
11019	Smart Thermostat - Elec Furnace/AC	SF	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	GDS	IN TRM	IN TRM	NEST website	IN TRM	BR 2013	RECS 2009	
11020	HVAC Tune-Up (Central AC)	MH	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	Cost: Assumes cost of inspection and tune-up
11021	HVAC Tune-Up (Heat Pump)	MH	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM / REM Rate	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	Winter kW: Assumes REM/Rate heating savings (furnace fan) across 982 full load heating hours per IN TRM for Evansville, IN Cost: Assumes cost of inspection and tune-up
11022	Energy Star Room A/C	MH	ROB	-	GDS/IN TRM	-	GDS/IN TRM	GDS/IN TRM	GDS/IN TRM	IN TRM	IN TRM	Mid Atl TRM	Mid Atl TRM	IN TRM	BR 2013	PA 2011	Consumption: Assumes federal standard 9.8 EER; Savings: Assumes full load hours of Ft. Wayne (closest to Big Rivers territory from IN TRM) - average of ENERGY STAR unit and CEE Tier 2 EER efficiencies (11.05 EER = (10.8+11.3)/2); Cost: Average of CEE Tier 2 and ENERGY STAR incremental costs
11023	High Efficiency Central AC - 16 SEER	MH	ROB	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	
11024	Ductless mini-split AC	MH	ROB	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	PA TRM	NEEP ICS / GDS	IN TRM	BR 2013	PA 2011	Cost: GDS calculation - assumes 75% of cost for single-family home based on tonnage of unit used in REM/Rate m
11025	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	ROB	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	
11026	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	MH	ROB	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	GDS	
11027	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	MH	ROB	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS / GDS	IN TRM	BR 2013	PA 2011	Useful Life: Assumed same as ASHP; Cost: Assumes incremental cost of efficient ASHP ($1,409 per NEEP ICS) + cost of baseline furnace ($1,673 per NEEP ICS)
11028	Dual Fuel Heat Pump (Replacing Electric Furnace)	MH	ROB	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS / GDS	IN TRM	BR 2013	GDS	Useful Life: Assumed same as ASHP; Cost: Assumes full cost of efficient ASHP ($6,793 per NEEP ICS) + cost of baseline furnace ($1,673 per NEEP ICS)
11029	Ductless mini-split HP (replacing ASHP)	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	PA TRM	NEEP ICS / GDS	IN TRM	BR 2013	PA 2011	Cost: GDS interpolation of NEEP ICS data to estimate cost of two 1.5-ton units
11030	Ductless mini-split HP (replacing furnace)	MH	Retrofit	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	PA TRM	NEEP ICS / GDS	IN TRM	BR 2013	GDS	Cost: Assumes full cost of two 1.5-ton ductless minisplit systems + cost of 3.5-ton ASHP (14 SEER) back-up systen
11031	ECM Furnace Fan	MH	ROB	-	GDS	-	Mid-Atl TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	GDS	Savings: Mid-Atl TRM estimates adjusted for estimated KY heating & cooling degree days
11032	Programmable Thermostat - Gas/AC	MH	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	IN TRM / REM Rate	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
11033	Programmable Thermostat - ASHP	MH	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
11034	Programmable Thermostat - Elec Furnace/AC	MH	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
11035	Smart Thermostat - Gas Heat / AC	MH	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	IN TRM / REM Rate	IN TRM	IN TRM	NEST website	IN TRM	BR 2013	RECS 2009	
11036	Smart Thermostat - ASHP	MH	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	GDS	IN TRM	IN TRM	NEST website	IN TRM	BR 2013	RECS 2009	
11037	Smart Thermostat - Elec Furnace/AC	MH	Retrofit	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	GDS	IN TRM	IN TRM	NEST website	IN TRM	BR 2013	RECS 2009	
11038	Energy Star Room A/C	SF	NC	-	GDS/IN TRM	-	GDS/IN TRM	GDS/IN TRM	GDS/IN TRM	IN TRM	IN TRM	Mid Atl TRM	Mid Atl TRM	IN TRM	BR 2013	GDS	Consumption: Assumes federal standard 9.8 EER; Savings: Assumes full load hours of Ft. Wayne (closest to Big Rivers territory from IN TRM) - average of ENERGY STAR unit and CEE Tier 2 EER efficiencies (11.05 EER = (10.8+11.3)/2); Cost: Average of CEE Tier 2 and ENERGY STAR incremental costs
11039	High Efficiency Central AC - 16 SEER	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	GDS	
11040	Ductless mini-split AC	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	PA TRM	NEEP ICS / GDS	IN TRM	BR 2013	GDS	Cost: GDS calculation using NEEP ICS to estimate ductless minisplit AC full cost and then subtracted full cost of ce
11041	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	GDS	
11042	Ground Source Heat Pump (HP Upgrade)	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	CenterPoint	IN TRM	BR 2013	PA 2011	Cost: Full cost of 4 ton GSHP ($17,500 per CenterPoint) minus full cost of 4 ton ASHP ($5,728 per NEEP ICS)

Big Rivers - Residential Measure Database - Sources

Measure ID	Measure Name	Home Type	ROB vs Retrofit vs. NC	Income Target	Base Elec. Use (kWh)	% Elec. Savings	Annual Elec. Savings (kWh)	Per Unit Winter NCP kW Savings	Per Unit Summer NCP kW Savings	Annual Non-elec. Savings (MMBTU)	Annual Water Savings (gal)	Useful Life	Incremental Full Cost	O&M Savings	Base Saturation	EE Saturation	Notes
11043	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS / GDS	IN TRM	BR 2013	GDS	Useful Life: Assumed same as ASHP; Cost: Assumes incremental cost of efficient ASHP ($1,523 per NEEP ICS) + cost of baseline furnace ($1,673 per NEEP ICS)
11044	Ductless mini-split HP (replacing ASHP)	SF	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	PA TRM	NEEP ICS / GDS	IN TRM	BR 2013	GDS	Cost: GDS interpolation of NEEP ICS data to estimate cost of two 2-ton units
11045	ECM Furnace Fan	SF	NC	-	GDS	-	Mid-Atl TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	GDS	Savings: Mid-Atl TRM estimates adjusted for estimated KY heating & cooling degree days
11046	Programmable Thermostat - Gas/AC	SF	NC	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	IN TRM / REM Rate	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
11047	Programmable Thermostat - ASHP	SF	NC	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
11048	Smart Thermostat - Gas Heat / AC	SF	NC	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	IN TRM / REM Rate	IN TRM	IN TRM	NEST website	IN TRM	BR 2013	RECS 2009	
11049	Smart Thermostat - ASHP	SF	NC	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	GDS	IN TRM	IN TRM	NEST website	IN TRM	BR 2013	RECS 2009	
11050	Energy Star Room A/C	MH	NC	-	GDS/IN TRM	-	GDS/IN TRM	GDS/IN TRM	GDS/IN TRM	IN TRM	IN TRM	Mid Atl TRM	Mid Atl TRM	IN TRM	BR 2013	GDS	Consumption: Assumes federal standard 9.8 EER; Savings: Assumes full load hours of Ft. Wayne (closest to Big Rivers territory from IN TRM) - average of ENERGY STAR unit and CEE Tier 2 EER efficiencies (11.05 EER = (10.8+11.3)/2); Cost: Average of CEE Tier 2 and ENERGY STAR incremental costs
11051	High Efficiency Central AC - 16 SEER	MH	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	GDS	
11052	Ductless mini-split AC	MH	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	PA TRM	NEEP ICS / GDS	IN TRM	BR 2013	GDS	Cost: GDS calculation - assumes 75% of cost for single-family home based on tonnage of unit used in REM/Rate m
11053	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	GDS	
11054	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	MH	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS / GDS	IN TRM	BR 2013	GDS	Useful Life: Assumed same as ASHP; Cost: Assumes incremental cost of efficient ASHP ($1,409 per NEEP ICS) + cost of baseline furnace ($1,673 per NEEP ICS)
11055	Ductless mini-split HP (replacing ASHP)	MH	NC	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	PA TRM	NEEP ICS / GDS	IN TRM	BR 2013	GDS	Cost: GDS interpolation of NEEP ICS data to estimate cost of two 1.5-ton units
11056	ECM Furnace Fan	MH	NC	-	GDS	-	Mid-Atl TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	GDS	Savings: Mid-Atl TRM estimates adjusted for estimated KY heating & cooling degree days
11057	Programmable Thermostat - Gas/AC	MH	NC	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	IN TRM / REM Rate	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
11058	Programmable Thermostat - ASHP	MH	NC	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	RECS 2009	
11059	Smart Thermostat - Gas Heat / AC	MH	NC	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	IN TRM / REM Rate	IN TRM	IN TRM	NEST website	IN TRM	BR 2013	RECS 2009	
11060	Smart Thermostat - ASHP	MH	NC	-	REM/Rate	-	IN TRM / REM Rate	IN TRM	IN TRM	GDS	IN TRM	IN TRM	NEST website	IN TRM	BR 2013	RECS 2009	
12000	Other																
12001	In Home Energy Display Monitor - Gas/CAC	SF	Retrofit	-	REM/Rate	-	ODC/MA	GDS	GDS	ODC/MA	GDS	VT TRM (2011)	ECW	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts ; Gas reduced based on gas:electric ratio for OPower ; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est) Base and EE saturation: GDS estimate
12002	Home Energy Reports - Gas/CAC	SF	Retrofit	-	REM/Rate	-	ODC/MA	GDS	GDS	ODC/MA	GDS	Opower	Opower	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts ; Gas reduced based on gas:electric ratio for OPower ; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est) Base and EE saturation: GDS estimate
12003	In Home Energy Display Monitor - ASHP	SF	Retrofit	-	REM/Rate	-	ODC/MA	GDS	GDS	GDS	GDS	VT TRM (2011)	ECW	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts ; Gas reduced based on gas:electric ratio for OPower ; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est) Base and EE saturation: GDS estimate
12004	Home Energy Reports - ASHP	SF	Retrofit	-	REM/Rate	-	ODC/MA	GDS	GDS	ODC/MA	GDS	Opower	Opower	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts ; Gas reduced based on gas:electric ratio for OPower ; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est) Base and EE saturation: GDS estimate
12005	In Home Energy Display Monitor - Elec Furn/CAC	SF	Retrofit	-	REM/Rate	-	ODC/MA	GDS	GDS	GDS	GDS	VT TRM (2011)	ECW	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts ; Gas reduced based on gas:electric ratio for OPower ; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est) Base and EE saturation: GDS estimate
12006	Home Energy Reports - Elec Furn/CAC	SF	Retrofit	-	REM/Rate	-	ODC/MA	GDS	GDS	ODC/MA	GDS	Opower	Opower	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts ; Gas reduced based on gas:electric ratio for OPower ; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est) Base and EE saturation: GDS estimate
12007	Two Speed Pool Pumps	SF	ROB	-	IN TRM	-	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	RECS 2009	CEE	
12008	Variable Speed Pool Pumps	SF	ROB	-	IN TRM	-	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	RECS 2009	CEE	
12009	Premium Efficiency Pool Pump Motor	SF	ROB	-	IN TRM	-	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	RECS 2009	CEE	
12010	In Home Energy Display Monitor - Gas/CAC	MH	Retrofit	-	REM/Rate	-	ODC/MA	GDS	GDS	ODC/MA	GDS	VT TRM (2011)	ECW	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts ; Gas reduced based on gas:electric ratio for OPower ; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est) Base and EE saturation: GDS estimate
12011	Home Energy Reports - Gas/CAC	MH	Retrofit	-	REM/Rate	-	ODC/MA	GDS	GDS	ODC/MA	GDS	Opower	Opower	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts ; Gas reduced based on gas:electric ratio for OPower ; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est) Base and EE saturation: GDS estimate
12012	In Home Energy Display Monitor - ASHP	MH	Retrofit	-	REM/Rate	-	ODC/MA	GDS	GDS	GDS	GDS	VT TRM (2011)	ECW	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts ; Gas reduced based on gas:electric ratio for OPower ; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est) Base and EE saturation: GDS estimate
12013	Home Energy Reports - ASHP	MH	Retrofit	-	REM/Rate	-	ODC/MA	GDS	GDS	ODC/MA	GDS	Opower	Opower	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts ; Gas reduced based on gas:electric ratio for OPower ; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est) Base and EE saturation: GDS estimate
12014	In Home Energy Display Monitor - Elec Furn/CAC	MH	Retrofit	-	REM/Rate	-	ODC/MA	GDS	GDS	GDS	GDS	VT TRM (2011)	ECW	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts ; Gas reduced based on gas:electric ratio for OPower ; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est) Base and EE saturation: GDS estimate
12015	Home Energy Reports - Elec Furn/CAC	MH	Retrofit	-	REM/Rate	-	ODC/MA	GDS	GDS	ODC/MA	GDS	Opower	Opower	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts ; Gas reduced based on gas:electric ratio for OPower ; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est) Base and EE saturation: GDS estimate
12016	In Home Energy Display Monitor - Gas/CAC	SF	NC	-	REM/Rate	-	ODC/MA	GDS	GDS	ODC/MA	GDS	VT TRM (2011)	ECW	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts ; Gas reduced based on gas:electric ratio for OPower ; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est)

Big Rivers - Residential Measure Database - Sources

Measure ID	Measure Name	Home Type	ROB vs Retrofit vs. NC	Income Target	Base Elec Use (kWh)	% Elec Savings	Annual Elec Savings (kWh)	Per Unit Winter NCP kW Savings	Per Unit Summer NCP kW Savings	Annual Non-elec Savings (MMBTU)	Annual Water Savings (gal)	Useful Life	Incremental / Full Cost	O&M Savings	Base Saturation	EE Saturation	Notes
12017	Home Energy Reports - Gas/CAC	SF	NC	-	REM/Rate	-	ODC/MA	GDS	GDS	ODC/MA	GDS	Opower	Opower	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts; Gas reduced based on gas:electric ratio for OPower; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est)
12018	In Home Energy Display Monitor - ASHP	SF	NC	-	REM/Rate	-	ODC/MA	GDS	GDS	GDS	GDS	VT TRM (2011)	ECW	GDS	BR 1013	GDS	Energy: Based on opt-in program in Massachusetts; Gas reduced based on gas:electric ratio for OPower; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est)
12019	Home Energy Reports - ASHP	SF	NC	-	REM/Rate	-	ODC/MA	GDS	GDS	ODC/MA	GDS	Opower	Opower	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts; Gas reduced based on gas:electric ratio for OPower; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est)
12020	Two Speed Pool Pumps	SF	NC	-	IN TRM	-	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	RECS 2009	GDS	
12021	Variable Speed Pool Pumps	SF	NC	-	IN TRM	-	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	RECS 2009	GDS	
12022	Premium Efficiency Pool Pump Motor	SF	HC	-	IN TRM	-	IN TRM	GDS	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	RECS 2009	GDS	
12023	In Home Energy Display Monitor - Gas/CAC	MH	NC	-	REM/Rate	-	ODC/MA	GDS	GDS	ODC/MA	GDS	VT TRM (2011)	ECW	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts; Gas reduced based on gas:electric ratio for OPower; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est)
12024	Home Energy Reports - Gas/CAC	MH	NC	-	REM/Rate	-	ODC/MA	GDS	GDS	ODC/MA	GDS	Opower	Opower	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts; Gas reduced based on gas:electric ratio for OPower; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est)
12025	In Home Energy Display Monitor - ASHP	MH	NC	-	REM/Rate	-	ODC/MA	GDS	GDS	GDS	GDS	VT TRM (2011)	ECW	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts; Gas reduced based on gas:electric ratio for OPower; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est)
12026	Home Energy Reports - ASHP	MH	NC	-	REM/Rato	-	ODC/MA	GDS	GDS	ODC/MA	GDS	Opower	Opower	GDS	BR 2013	GDS	Energy: Based on opt-in program in Massachusetts; Gas reduced based on gas:electric ratio for OPower; reduced by 5% to account for cross-cutting savings Demand: Assumed consistent conservation across all annual hours (GDS Est)
13000	Multi-Family Units																
13001	Multi-Family Homes Efficiency Kit	MF	Retrofit	-	GDS calc	-	DEP NES	GDS calc	GDS calc	GDS	GDS calc	GDS	DEP NES	GDS	BR 2013	BR 2013	Consumption: Estimate based on SF consumption, reduced by ratio of estimated square footage of apartment to single-family home; % savings - EM&V verified savings for Duke Energy Progress PY 2012 Neighborhood Energy Saver Program (program is direct-install of various EE measures such as CFLs and low-flow showerheads); Water Savings: Assumes ~2 faucet aerators & 1 showerhead Useful Life: GDS estimate of 8 years based on CFLs, low flow showerheads and low flow aerators being the predominant energy savers in the kit with measure lives of 10, 5, and 10 years respectively; Cost: Incentive Cost per participant in application for program approval of DEP NES program; O&M Savings: Assumes ~9 CFLs installed per home Base Sat: Assumes homes with electric heating and water heating are eligible; EE Sat: Saturation of efficient lighting in multifamily homes in BR territory
13001	Multi-Family Homes Efficiency Kit	MF	NC	-	GDS calc	-	DEP NES	GDS calc	GDS calc	GDS	GDS calc	GDS	DEP NES	GDS	BR 2013	BR 2013	Consumption: Estimate based on SF consumption, reduced by ratio of estimated square footage of apartment to single-family home; % savings - EM&V verified savings for Duke Energy Progress PY 2012 Neighborhood Energy Saver Program (program is direct-install of various EE measures such as CFLs and low-flow showerheads); Water Savings: Assumes ~1 faucet aerators & 1 showerhead Useful Life: GDS estimate of 8 years based on CFLs, low flew showerheads and low flow aerators being the predominant energy savers in the kit with measure lives of 10, 5, and 10 years respectively; Cost: Incentive Cost per participant in application for program approval of DEP NES program; O&M Savings: Assumes ~9 CFLs installed per home Base Sat: Assumes homes with electric heating and water heating are eligible; EE Sat: Saturation of efficient lighting in multifamily homes in BR territory
14000	New Construction Homes - Single Family																
14001	New Construction - 15% more efficient (w/AC only)	SF	NC	-	REM/Rate	-	GDS	GDS	GDS	GDS	IN TRM	GDS	IN TRM	IN TRM	BR 2013	GDS	
14002	New Construction - 15% more efficient (w/Elec. HP)	SF	NC	-	REM/Rate	-	GDS	GDS	GDS	GDS	IN TRM	GDS	IN TRM	IN TRM	BR 2013	GDS	
14003	New Construction - 15% more efficient (w/ Dual-Fuel HP (w/gas))	SF	NC	-	REM/Rate	-	GDS	GDS	GDS	GDS	IN TRM	GDS	IN TRM	IN TRM	BR 2013	GDS	
14004	New Construction - 15% more efficient (w/ Geothermal HP)	SF	NC	-	REM/Rate	-	GDS	GDS	GDS	GDS	IN TRM	GDS	IN TRM	IN TRM	BR 2013	GDS	
14005	New Construction - 30% more efficient (w/AC only)	SF	NC	-	REM/Rate	-	GDS	GDS	GDS	GDS	IN TRM	GDS	IN TRM	IN TRM	BR 2013	GDS	
14006	New Construction - 30% more efficient (w/Elec. HP)	SF	NC	-	REM/Rate	-	GDS	GDS	GDS	GDS	IN TRM	GDS	IN TRM	IN TRM	BR 2013	GDS	
14007	New Construction - 30% more efficient (w/ Dual-Fuel HP (w/gas))	SF	NC	-	REM/Rate	-	GDS	GDS	GDS	GDS	IN TRM	GDS	IN TRM	IN TRM	BR 2013	GDS	
14008	New Construction - 30% more efficient (w/ Geothermal HP)	SF	NC	-	REM/Rate	-	GDS	GDS	GDS	GDS	IN TRM	GDS	IN TRM	IN TRM	BR 2013	GDS	
14009	New Construction - 15% more efficient (w/AC only)	MH	NC	-	REM/Rate	-	GDS	GDS	GDS	GDS	IN TRM	GDS	IN TRM	IN TRM	BR 2013	GDS	
14010	New Construction - 15% more efficient (w/Elec. HP)	MH	NC	-	REM/Rate	-	GDS	GDS	GDS	GDS	IN TRM	GDS	IN TRM	IN TRM	BR 2013	GDS	
14011	New Construction - 30% more efficient (w/AC only)	MH	NC	-	REM/Rate	-	GDS	GDS	GDS	GDS	IN TRM	GDS	IN TRM	IN TRM	BR 2013	GDS	
14012	New Construction - 30% more efficient (w/Elec. HP)	MH	NC	-	REM/Rate	-	GDS	GDS	GDS	GDS	IN TRM	GDS	IN TRM	IN TRM	BR 2013	GDS	
15000	Early Retirement																
15001	Energy Star Room A/C - Early Retirement	SF	ER1	-	GDS/IN TRM	-	GDS/IN TRM	GDS/IN TRM	GDS/IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	PA 2011	Consumption: Assumes baseline of 7.7 EER per IN TRM; Savings: Assumes full load hours of Ft. Wayne (closest to Big Rivers territory from IN TRM) - average of ENERGY STAR unit and CEE Tier 2 EER efficiencies (11.05 EER = (10.8+11.3)/2)
15002	Energy Star Room A/C - Early Retirement	SF	ER2		GDS/IN TRM	-	GDS/IN TRM	GDS/IN TRM	GDS/IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	PA 2011	
15003	Energy Star Room A/C - Early Retirement	SF	ER3		GDS/IN TRM	-	GDS/IN TRM	GDS/IN TRM	GDS/IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	PA 2011	
15004	High Efficiency Central AC/Early Retire - 16 SEER	SF	ER1	-	REM/Rato	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	
15005	High Efficiency Central AC/Early Retire - 16 SEER	SF	ER2	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	
15006	High Efficiency Central AC/Early Retire - 16 SEER	SF	ER3	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	
15007	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9	SF	ER1	-	REM/Rete	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	
15008	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9	SF	ER2	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	
15009	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9	SF	ER3	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	
15010	Ground Source Heat Pump/Early Retire (HP Upgrade)	SF	ER1	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	CenterPoint	IN TRM	BR 2013	PA 2011	Cost: Full cost of 4 ton GSHP ($17,500 per CenterPoint) minus full cost of 4 ton ASHP ($5,728 per NEEP ICS)
15011	Ground Source Heat Pump/Early Retire (HP Upgrade)	SF	ER2	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	CenterPoint	IN TRM	BR 2013	PA 2011	Cost: Full cost of 4 ton GSHP ($17,500 per CenterPoint) minus full cost of 4 ton ASHP ($5,728 per NEEP ICS)
15012	Ground Source Heat Pump/Early Retire (HP Upgrade)	SF	ER3	-	REM/Rato	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	CenterPoint	IN TRM	BR 1013	PA 2011	Cost: Full cost of 4 ton GSHP ($17,500 per CenterPoint) minus full cost of 4 ton ASHP ($5,728 per NEEP ICS)
15013	Heat Pump/Early Retire (Replacing Electric Furnace)	SF	ER1	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	GDS	
15014	Heat Pump/Early Retire (Replacing Electric Furnace)	SF	ER2	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	GDS	
15015	Heat Pump/Early Retire (Replacing Electric Furnace)	SF	ER3	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	GDS	
15016	Energy Star Room A/C - Early Retirement	MH	ER1	-	GDS/IN TRM	-	GDS/IN TRM	GDS/IN TRM	GDS/IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	PA 2011	Consumption: Assumes baseline of 7.7 EER per IN TRM; Savings: Assumes full load hours of Ft. Wayne (closest to Big Rivers territory from IN TRM) - average of ENERGY STAR unit and CEE Tier 2 EER efficiencies (11.05 EER = (10.8+11.3)/2)
15017	Energy Star Room A/C - Early Retirement	MH	ER2		GDS/IN TRM	-	GDS/IN TRM	GDS/IN TRM	GDS/IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	PA 2011	
15018	Energy Star Room A/C - Early Retirement	MH	ER3		GDS/IN TRM	-	GDS/IN TRM	GDS/IN TRM	GDS/IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	IN TRM	BR 2013	PA 2011	
15019	High Efficiency Central AC/Early Retire - 16 SEER	MH	ER1	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	
15020	High Efficiency Central AC/Early Retire - 16 SEER	MH	ER2	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	
15021	High Efficiency Central AC/Early Retire - 16 SEER	MH	ER3	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	IN TRM	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	
15022	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9	MH	ER1	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	
15023	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9	MH	ER2	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	
15024	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9	MH	ER3	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	PA 2011	

Big Rivers - Residential Measure Database - Sources

Measure ID	Measure Name	Home Type (SF, All, LG MF, SM MF, MH)	ROB vs. Retrofit vs. NC	Income Target	Base Elec Use (kWh)	% Elec Savings	Annual Elec Savings (kWh)	Per Unit Winter NCP kW Savings	Per Unit Summer NCP kW Savings	Annual Non-elec. Savings (MMBTU)	Annual Water Savings (gal.)	Useful Life	Incremental /Full Cost	O&M Savings	Base Saturation	EE Saturation	Notes
15025	Heat Pump/Early Retire (Replacing Electric Furnace)	MH	ER1	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	GDS	
15026	Heat Pump/Early Retire (Replacing Electric Furnace)	MH	ER2	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	GDS	
15027	Heat Pump/Early Retire (Replacing Electric Furnace)	MH	ER3	-	REM/Rate	-	REM/Rate	REM/Rate	REM/Rate	GDS	IN TRM	IN TRM	NEEP ICS	IN TRM	BR 2013	GDS	

ACEEE (A041): Set-Top Boxes: Opportunities and Issues in Setting Efficiency Standards, Report Number A041.
ARK TRM: Arkansas Technical Reference Manual, Version 3.0
BR 2013: Big Rivers Saturation Survey, 2013
BR 2013 / Mid-Atl TRM: Uses estimate of showerheads/faucets per home from Mid-Atl TRM and saturation of electric water heating to calculate measure saturation
BR 2013 / US DOE: Big Rivers Saturation Survey, 2013 used to estimate bulbs per home; % of sockets that are specialty vs. standard etc. taken from the January 2012 Department of Energy report, "2010 U.S. Lighting Market Characterization.
CEE: Email exchange with Eileen Eaton (CEE) on 6/15/2012. Speculated based on industry sources that ~ 1/3 of all pool pumps are two-speed or greater
CenterPoint: CenterPoint Energy - 2010 Brochure title, "Geothermal Heat Pumps Get to Know the Facts," Accessed March 2014
DEP NES: EM&V report for Duke Energy Progress PY 2012 Neighborhood Energy Saver Program
ECW: Energy Center of Wisconsin - "Focus on Energy - PowerCost Monitor Study", 2010
ES App Calc.: Used major assumptions and algorithms included in the ES Appliance Savings Calculator (Updated February 2013) ; modified selected assumptions for current analysis ; see individual worksheets included in workbook
ES Calc-Office: ENERGY STAR Office Equipment Calculator, accessed February 2014
ES Refrigerators 5.0: ENERGY STAR Product Specification for Residential Refrigerators and Freezers version 5.0
ES Savings & Cost: ENERGY STAR Qualified Homes, Version 3 Savings & Cost Estimate Summary
ES Unit Ship: Data from various ENERGY STAR Unit Shipment and Market Penetration Reports
ES 7.0: ENERGY STAR 7.0 clothes washer specs
ES 7.0 / GDS calc: GDS calculation based on ES 7.0 clothes washer specs
ES 7.0 / IN TRM: ENERGY STAR 7.0 clothes washer specs and IN TRM used to calculate demand savings
GDS: GDS assumption. See source notes for any necessary detail
GDS Calc.: GDS calculation. See source notes.
GDS Calc / NMR: GDS calculation using Nexus Market Research report that indicates the average delta watts for efficient torchieres
GDS/IN TRM: GDS estimate or calculation using IN TRM information
GDS/IllTRM: GDS estimate or calculation using Ill TRM information
GDS/NEEP RLS: GDS calculation using NEEP RLS 2012 data
ILL TRM: State of Illinois Energy Efficiency Technical Reference Manual. Final Technical Version. July 18th, 2012.
IN TRM: Indiana Technical Resource Manual, version 1.0. January 10, 2013
IN TRM / GDS calc: IN TRM algorithms and data used along with additional GDS estimates of specific parameters
IN TRM / REM/Rate: IN TRM savings factor used with REM/Rate estimate of base consumption
MA Baseline 2009: Massachusetts Residential Appliance Saturation Survey (RASS), Opinion Dynamics Corporation, April 2009
MEMD: Michigan Energy Measures Database, accessed February, 2014.
Mid Atl TRM: Mid-Atlantic Technical Reference Manual. Version 3.0, March 2013
NEEP HPWH: NEEP Northeast and Mid-Atlantic Heat Pump Water Heater Market Strategies Report, December 2012.
NEEP ICS: Incremental Cost Study Phase Two Final Report, Chaired by the Northeast Energy Efficiency Partnerships, January, 2013.
NEEP ICS / GDS: Utilized Incremental Cost Study database to estimate cost
NEEP RLS: Residential Lighting Strategy, March 2012
NEST website: MSRP for NEST thermostat in early 2014
NJ CEP: New Jersey Board of Public Utilities, New Jersey Clean Energy Program Protocols to Measure Resource Savings, August 2012
ODC/MA: Massachusetts 3-Year Cross-Cutting Behavioral Program Evaluation Integrated Report. July 2012. Completed by Opinion Dynamics & Navigant Consulting
Opower: Memo from Jim Kapsis regarding Best Practices for Modeling Behavioral Energy Efficiency in Potential Studies - memo noted average cost ranging from $8 - $12.
PA 2011: Pennsylvania Statewide Residential End-Use and Saturation Study. GDS Associates. 2011.
PA TRM: Pennsylvania Public Utility Commission. Technical Reference Manual, June 2013
RECS 2009: Residential Energy Consumption Survey. EIA. 2009. Restricted to KY, AL, MS sub-region.
REM/Rate: Building Energy Modeling Software. Prototype homes were modeled to be calibrated with the load forecast in 2014.
RIA 2010: Electronics and Energy Efficiency: A Plug Load Characterization Study. Appendix K. Prepared by Research Into Action for Southern California Edison.
VT TRM: Technical Reference Manual. Measure Savings Algorithms and Cost Assumptions. Efficiency Vermont. November 4, 2013.
VT TRM (2010): Technical Reference Manual. Measure Savings Algorithms and Cost Assumptions. Efficiency Vermont. December 31, 2011.

Measure-level Benefit-Cost Ratios

Measure #	*Measure Name*	*TRC Test*	*Utility Cost Test*	*Societal Cost Test*	*Part. Test*	*RIM Test*
1000	Appliances					
1001	Energy Star Compliant Top-Mount Refrigerator	1.58	4.53	1.58	1.01	1.57
1002	Energy Star Compliant Side-by-Side Refrigerator	1.87	5.34	1.87	1.13	1.66
1003	Energy Star Compliant Chest Freezer	0.93	2.65	0.93	1.60	0.58
1004	Energy Star Compliant Upright Freezer (Manual Def.)	0.97	2.76	0.97	1.65	0.58
1005	Energy Star Dehumidifer	2.77	7.91	2.77	5.45	0.51
1006	Second Refrigerator Turn In	4.13	4.13	4.13	7.13	0.58
1007	Second Freezer Turn In	3.78	3.78	3.78	6.57	0.57
1008	Energy Star Compliant Top-Mount Refrigerator	1.58	4.53	1.58	1.01	1.57
1009	Energy Star Compliant Side-by-Side Refrigerator	1.87	5.34	1.87	1.13	1.66
1010	Energy Star Compliant Chest Freezer	0.93	2.65	0.93	1.60	0.58
1011	Energy Star Compliant Upright Freezer (Manual Def.)	0.97	2.76	0.97	1.65	0.58
1012	Energy Star Dehumidifer	2.77	7.91	2.77	5.45	0.51
1013	Second Refrigerator Turn In	4.13	11.81	4.13	6.48	0.64
1014	Second Freezer Turn In	3.74	10.69	3.74	5.92	0.63
1015	Energy Star Compliant Top-Mount Refrigerator	1.59	4.54	1.59	1.01	1.58
1016	Energy Star Compliant Side-by-Side Refrigerator	1.88	5.36	1.88	1.13	1.66
1017	Energy Star Compliant Chest Freezer	0.66	1.88	0.66	1.60	0.41
1018	Energy Star Compliant Upright Freezer (Manual Def.)	0.96	0.96	0.96	2.30	0.42
1019	Energy Star Dehumidifer	4.22	4.22	4.22	6.10	0.69
1020	Energy Star Compliant Top-Mount Refrigerator	1.58	4.53	1.58	1.01	1.57
1021	Energy Star Compliant Side-by-Side Refrigerator	1.87	5.34	1.87	1.13	1.66
1022	Energy Star Compliant Chest Freezer	0.93	2.65	0.93	1.60	0.58
1023	Energy Star Compliant Upright Freezer (Manual Def.)	0.97	2.76	0.97	1.65	0.58
1024	Energy Star Dehumidifer	2.77	7.91	2.77	5.45	0.51
2000	Consumer Electronics - Single Family, Mobile Home					
2001	Efficient Televisions	1.53	5.05	1.53	2.11	0.67
2002	Energy Star Desktop Computer	1.30	4.67	1.30	2.97	0.44
2003	Energy Star Computer Monitor	1.39	4.93	1.39	3.00	0.46
2004	Energy Star Laptop Computer	0.41	1.45	0.41	1.17	0.36
2005	Smart Strip Power Strip	0.18	0.63	0.18	0.70	0.28
2006	Efficient Set Top Box	3.51	10.04	3.51	6.94	0.51
2007	Efficient Televisions	1.53	5.05	1.53	2.11	0.67
2008	Energy Star Desktop Computer	1.30	4.67	1.30	2.97	0.44
2009	Energy Star Computer Monitor	1.39	4.93	1.39	3.00	0.46
2010	Energy Star Laptop Computer	0.41	1.45	0.41	1.17	0.36
2011	Smart Strip Power Strip	0.18	0.63	0.18	0.70	0.28
2012	Efficient Set Top Box	3.51	10.04	3.51	6.94	0.51
2013	Efficient Televisions	1.53	5.05	1.53	2.11	0.67
2014	Energy Star Desktop Computer	1.30	4.67	1.30	2.97	0.44
2015	Energy Star Computer Monitor	1.39	4.93	1.39	3.00	0.46
2016	Energy Star Laptop Computer	0.41	1.45	0.41	1.17	0.36
2017	Smart Strip Power Strip	0.18	0.63	0.18	0.70	0.28
2018	Efficient Set Top Box	3.51	10.04	3.51	6.94	0.51
2019	Efficient Televisions	1.53	5.05	1.53	2.11	0.67
2020	Energy Star Desktop Computer	1.30	4.67	1.30	2.97	0.44
2021	Energy Star Computer Monitor	1.39	4.93	1.39	3.00	0.46
2022	Energy Star Laptop Computer	0.41	1.45	0.41	1.17	0.36
2023	Smart Strip Power Strip	0.18	0.63	0.18	0.70	0.28
2024	Efficient Set Top Box	3.51	10.04	3.51	6.94	0.51
3000	Lighting - Single Family, Mobile Home					
3001	Standard CFL - Average Use (3 hours/day)	3.54	7.71	3.54	4.36	0.67
3002	Standard LED - Average Use (3 hours/day)	2.68	6.43	2.68	3.03	0.77
3003	Specialty CFL	9.49	24.60	9.49	10.36	0.80
3004	Specialty LED	1.33	3.69	1.33	1.63	0.73
3005	Energy Star Torchiere	12.52	30.79	12.52	14.26	0.75
3006	LED Nightlight	6.25	7.40	6.25	10.61	0.37
3007	Exterior CFL Fixture	6.50	16.39	6.50	10.17	0.61
3008	Exterior LED Fixture	6.71	17.32	6.71	10.57	0.61
3009	Standard CFL - Average Use (3 hours/day)	3.54	7.71	3.54	4.36	0.67
3010	Standard LED - Average Use (3 hours/day)	2.68	6.43	2.68	3.03	0.77
3011	Specialty CFL	9.49	24.60	9.49	10.36	0.80
3012	Specialty LED	1.33	3.69	1.33	1.63	0.73
3013	Energy Star Torchiere	12.52	30.79	12.52	14.26	0.75
3014	LED Nightlight	6.25	7.40	6.25	10.61	0.37
3015	Exterior CFL Fixture	6.50	16.39	6.50	10.17	0.61
3016	Exterior LED Fixture	6.71	17.32	6.71	10.57	0.61
3017	Standard CFL - Average Use (3 hours/day)	3.54	7.71	3.54	4.36	0.67
3018	Standard LED - Average Use (3 hours/day)	2.68	6.43	2.68	3.03	0.77
3019	Specialty CFL	9.49	24.60	9.49	10.36	0.80
3020	Specialty LED	1.33	3.69	1.33	1.63	0.73
3021	Energy Star Torchiere	12.52	30.79	12.52	14.26	0.75
3022	LED Nightlight	6.25	7.40	6.25	10.61	0.37
3023	Exterior CFL Fixture	6.50	16.39	6.50	10.17	0.61
3024	Exterior LED Fixture	6.71	17.32	6.71	10.57	0.61
3025	Standard CFL - Average Use (3 hours/day)	3.54	7.71	3.54	4.36	0.67
3026	Standard LED - Average Use (3 hours/day)	2.68	6.43	2.68	3.03	0.77
3027	Specialty CFL	9.49	24.60	9.49	10.36	0.80

Measure-level Benefit-Cost Ratios

Measure #	Measure Name	TRC Test	Utility Cost Test	Societal Cost Test	Part. Test	RIM Test
3028	Specialty LED	1.33	3.69	1.33	1.63	0.73
3029	Energy Star Torchiere	12.52	30.79	12.52	14.26	0.75
3030	LED Nightlight	6.25	7.40	6.25	10.61	0.37
3031	Exterior CFL Fixture	6.50	16.39	6.50	10.17	0.61
3032	Exterior LED Fixture	6.71	17.32	6.71	10.57	0.61
4000	Electric Water Heating - Single Family / Mobile Homes					
4001	Low Flow Faucet Aerators	9.24	5.84	9.24	11.67	0.46
4002	Low Flow Showerhead	21.97	25.84	21.97	28.61	0.58
4003	Water Heater Blanket	0.56	1.60	0.56	1.34	0.42
4004	Water Heater Pipe Wrap	7.98	22.79	7.98	12.42	0.64
4005	Heat Pump Water Heater (resistance heat)	0.89	1.30	0.46	1.42	0.46
4006	Heat Pump Water Heater (ASHP heat)	1.62	3.39	1.19	2.43	0.59
4007	Solar Water Heating	0.30	1.26	-0.05	0.69	0.53
4008	Energy Star Dishwasher (Electric Water Heating)	5.27	8.92	5.27	5.16	1.04
4009	Energy Star Dishwasher (Non-Electric WH)	4.46	5.57	4.46	4.50	1.28
4010	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	2.88	1.58	2.88	3.42	0.50
4011	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	2.74	1.17	2.74	3.23	0.45
4012	Low Flow Faucet Aerators	9.24	5.84	9.24	11.67	0.46
4013	Low Flow Showerhead	21.97	25.84	21.97	28.61	0.58
4014	Water Heater Blanket	0.56	1.60	0.56	1.34	0.42
4015	Water Heater Pipe Wrap	7.98	22.79	7.98	12.42	0.64
4016	Energy Star Dishwasher (Electric Water Heating)	5.27	8.92	5.27	5.16	1.04
4017	Energy Star Dishwasher (Non-Electric WH)	4.46	5.57	4.46	4.50	1.28
4018	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	2.88	1.58	2.88	3.42	0.50
4019	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	2.74	1.17	2.74	3.23	0.45
4020	Low Flow Faucet Aerators	9.24	5.84	9.24	11.67	0.46
4021	Low Flow Showerhead	21.97	25.84	21.97	28.61	0.58
4022	Water Heater Blanket	0.56	1.60	0.56	1.34	0.42
4023	Water Heater Pipe Wrap	7.98	22.79	7.98	12.42	0.64
4024	Heat Pump Water Heater (ASHP heat)	1.62	3.39	1.19	2.43	0.59
4025	Solar Water Heating	0.30	1.26	-0.05	0.69	0.53
4026	Energy Star Dishwasher (Electric Water Heating)	5.27	8.92	5.27	5.16	1.04
4027	Energy Star Dishwasher (Non-Electric WH)	4.46	5.57	4.46	4.50	1.28
4028	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	2.88	1.58	2.88	3.42	0.50
4029	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	2.74	1.17	2.74	3.23	0.45
4030	Low Flow Faucet Aerators	9.24	5.84	9.24	11.67	0.46
4031	Low Flow Showerhead	21.97	25.84	21.97	28.61	0.58
4032	Water Heater Blanket	0.56	1.60	0.56	1.34	0.42
4033	Water Heater Pipe Wrap	7.98	22.79	7.98	12.42	0.64
4034	Energy Star Dishwasher (Electric Water Heating)	5.27	8.92	5.27	5.16	1.04
4035	Energy Star Dishwasher (Non-Electric WH)	4.46	5.57	4.46	4.50	1.28
4036	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	2.88	1.58	2.88	3.42	0.50
4037	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	2.74	1.17	2.74	3.23	0.45
5000	Space Heating and Space Cooling Shell Measures - Single Family Homes w/ Electric AC Only & Gas Heat					
5001	Insulation - Ceiling (R-0 to R-19)	3.37	2.93	3.37	5.81	1.32
5002	Insulation - Floor (R-0 to R-19)	1.09	0.07	1.09	2.47	0.13
5003	Energy Star Windows	0.26	0.40	0.22	0.71	0.28
5004	Insulation -Ceiling (R-19 to R-38)	0.48	0.30	0.44	1.17	0.26
5005	Insulation -Ceiling (R-0 to R-38)	2.98	2.50	2.95	5.21	1.21
5006	Insulation -Ceiling (R-9 to R-38)	0.68	0.47	0.65	1.51	0.38
5007	Insulation -Ceiling (R-11 to R-38)	0.62	0.46	0.59	1.37	0.38
5008	Air Sealing	0.67	0.47	0.67	1.53	0.40
5009	Duct Sealing	1.31	3.04	1.31	1.51	1.09
5010	Radiant Barriers	2.96	8.46	2.96	1.87	1.58
5011	Complete Weatherization Package	1.45	0.68	1.45	2.49	0.49
5012	Energy Star Windows	0.98	-0.03	0.37	1.76	-0.03
5013	Insulation -Ceiling (R-38 Grade 2 to Grade 1)	2.10	0.03	0.11	2.57	0.03
5014	Air Sealing	0.99	0.74	0.99	2.01	0.68
5015	Duct Sealing	11.55	28.34	11.55	8.19	2.15
5016	Radiant Barriers	2.84	8.00	2.84	1.45	2.04
6000	Space Heating and Space Cooling Shell Measures - Single Family Homes w/ Electric Heat Pump					
6001	Insulation - Ceiling (R-0 to R-19)	5.68	16.23	5.68	6.68	0.85
6002	Insulation - Floor (R-0 to R-19)	1.91	5.45	1.91	2.68	0.71
6003	Energy Star Windows	0.40	1.04	0.36	0.72	0.53
6004	Insulation -Ceiling (R-19 to R-38)	0.86	2.34	0.82	1.22	0.70
6005	Insulation -Ceiling (R-0 to R-38)	5.07	14.39	5.03	5.92	0.85
6006	Insulation -Ceiling (R-9 to R-38)	1.19	3.30	1.15	1.59	0.74
6007	Insulation -Ceiling (R-11 to R-38)	1.06	2.93	1.03	1.44	0.73
6008	Air Sealing	1.09	3.10	1.09	1.57	0.69
6009	Duct Sealing	3.87	11.05	3.87	1.56	2.48
6010	Radiant Barriers	3.20	9.13	3.20	1.93	1.66
6011	Complete Weatherization Package	1.24	1.03	1.24	2.07	0.55
6012	Energy Star Windows	1.23	1.75	0.61	1.67	0.58
6013	Insulation -Ceiling (R-38 Grade 2 to Grade 1)	2.03	0.14	0.05	2.43	0.11
6014	Air Sealing	0.90	2.56	0.90	1.84	0.49
6015	Duct Sealing	29.36	83.89	29.36	6.27	4.68
6016	Radiant Barriers	3.06	8.74	3.06	1.35	2.27
7000	Space Heating and Space Cooling Shell Measures - Single Family Homes w/ Electric Furnace					

Measure-level Benefit-Cost Ratios

Measure #	Measure Name	TRC Test	Utility Cost Test	Societal Cost Test	Part. Test	RIM Test
7001	Insulation - Ceiling (R-0 to R-19)	7.97	22.78	7.97	10.86	0.73
7002	Insulation - Floor (R-0 to R-19)	3.02	8.64	3.02	4.75	0.64
7003	Energy Star Windows	0.49	1.28	0.45	0.88	0.53
7004	Insulation -Ceiling (R-19 to R-38)	1.22	3.38	1.18	1.89	0.64
7005	Insulation -Ceiling (R-0 to R-38)	7.12	20.27	7.09	9.69	0.73
7006	Insulation -Ceiling (R-9 to R-38)	1.68	4.71	1.65	2.56	0.65
7007	Insulation -Ceiling (R-11 to R-38)	1.52	4.25	1.49	2.30	0.66
7008	Air Sealing	1.61	4.61	1.61	2.58	0.63
7009	Duct Sealing	4.22	12.06	4.22	2.00	2.11
7010	Radiant Barriers	2.37	6.77	2.37	0.39	6.05
7011	Complete Weatherization Package	1.46	1.26	1.46	2.51	0.55
8000	Space Heating and Space Cooling Shell Measures - Mobile Homes w/ Electric AC Only & Gas Heat					
8001	Air Sealing	0.50	0.14	0.50	1.45	0.11
8002	Insulation - Floor (R-11 to R-30)	0.51	-0.04	0.41	1.34	-0.04
8003	Energy Star Windows	0.40	0.24	0.33	1.00	0.21
8004	Duct Sealing	2.02	4.69	2.02	2.21	1.18
8005	Complete Weatherization Package	1.19	0.52	1.19	2.28	0.40
8006	Air Sealing	1.12	0.08	1.12	2.84	0.07
8007	Insulation - Floor (R-19 to R-30)	1.35	-0.01	1.14	3.00	-0.01
8008	Energy Star Windows	2.64	0.00	1.53	4.74	0.00
8009	Duct Sealing	18.24	31.06	18.24	23.93	1.39
9000	Space Heating and Space Cooling Shell Measures - Mobile Homes w/ Electric Heat Pump					
9001	Air Sealing	0.59	1.67	0.59	1.47	0.40
9002	Insulation - Floor (R-11 to R-30)	1.00	2.56	0.90	1.40	0.70
9003	Energy Star Windows	0.67	1.72	0.60	1.03	0.63
9004	Duct Sealing	7.60	21.71	7.60	2.12	3.58
9005	Complete Weatherization Package	1.95	1.53	1.95	2.50	0.74
9006	Air Sealing	0.55	1.58	0.55	1.41	0.39
9007	Insulation - Floor (R-19 to R-30)	1.41	3.42	1.20	1.69	0.81
9008	Energy Star Windows	1.88	2.20	0.77	2.12	0.77
9009	Duct Sealing	60.63	173.22	60.63	9.88	6.14
10000	Space Heating and Space Cooling Shell Measures - Mobile Homes w/ Electric Heat					
10001	Air Sealing	1.07	3.06	1.07	2.40	0.45
10002	Insulation - Floor (R-11 to R-30)	1.36	3.60	1.26	2.25	0.59
10003	Energy Star Windows	0.91	2.39	0.84	1.52	0.58
10004	Duct Sealing	8.03	22.96	8.03	2.94	2.73
10005	Complete Weatherization Package	2.12	1.70	2.12	2.85	0.70
11000	Space Heating and Space Cooling Equipment - Single Family / Mobile Homes					
11001	HVAC Tune-Up (Central AC)	0.51	1.46	0.51	0.73	0.70
11002	HVAC Tune-Up (Heat Pump)	1.27	3.62	1.27	1.84	0.69
11003	Energy Star Room A/C	0.69	1.97	0.69	1.04	0.67
11004	High Efficiency Central AC - 16 SEER	0.47	0.99	0.35	0.77	0.54
11005	Ductless mini-split AC	0.71	2.04	0.71	0.75	0.96
11006	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	0.67	1.46	0.51	1.18	0.50
11007	Ground Source Heat Pump (HP Upgrade)	0.82	1.01	0.35	1.43	0.37
11008	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	1.76	4.88	1.71	3.32	0.52
11009	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	1.61	5.39	1.53	1.84	0.74
11010	Dual Fuel Heat Pump (Replacing Electric Furnace)	1.37	4.21	1.35	2.28	0.58
11011	Ductless mini-split HP (replacing ASHP)	0.57	1.63	0.57	0.67	0.86
11012	Ductless mini-split HP (replacing furnace)	0.76	2.17	0.76	1.30	0.58
11013	ECM Furnace Fan	1.19	3.39	1.19	2.19	0.54
11014	Programmable Thermostat - Gas/AC	14.18	16.46	14.18	30.18	0.51
11015	Programmable Thermostat - ASHP	15.47	44.19	15.47	29.96	0.52
11016	Programmable Thermostat - Elec Furnace/AC	24.69	70.54	24.69	47.61	0.52
11017	Smart Thermostat - Gas Heat / AC	1.99	2.31	1.99	4.54	0.43
11018	Smart Thermostat - ASHP	2.17	6.21	2.17	4.51	0.48
11019	Smart Thermostat - Elec Furnace/AC	3.47	9.91	3.47	6.99	0.50
11020	HVAC Tune-Up (Central AC)	0.39	1.12	0.39	0.57	0.68
11021	HVAC Tune-Up (Heat Pump)	0.97	2.78	0.97	1.42	0.69
11022	Energy Star Room A/C	0.69	1.97	0.69	1.04	0.67
11023	High Efficiency Central AC - 16 SEER	0.36	0.65	0.23	0.66	0.43
11024	Ductless mini-split AC	0.70	2.00	0.70	0.70	1.00
11025	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	0.52	0.99	0.35	1.02	0.41
11026	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	1.35	3.70	1.30	2.70	0.49
11027	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	1.37	4.52	1.29	1.55	0.75
11028	Dual Fuel Heat Pump (Replacing Electric Furnace)	1.10	3.36	1.07	1.87	0.57
11029	Ductless mini-split HP (replacing ASHP)	0.49	1.40	0.49	0.57	0.86
11030	Ductless mini-split HP (replacing furnace)	0.64	1.82	0.64	1.12	0.57
11031	ECM Furnace Fan	1.19	3.39	1.19	2.19	0.54
11032	Programmahle Thermostat - Gas/AC	9.87	10.44	9.87	21.24	0.50
11033	Programmahle Thermostat - ASHP	10.89	31.10	10.89	21.19	0.51
11034	Programmable Thermostat - Elec Furnace/AC	17.66	50.47	17.66	34.17	0.52
11035	Smart Thermostat - Gas Heat / AC	1.39	1.47	1.39	3.29	0.39
11036	Smart Thermostat - ASHP	1.53	4.37	1.53	3.28	0.47
11037	Smart Thermostat - Elec Furnace/AC	2.48	7.09	2.48	5.10	0.49
11038	Energy Star Room A/C	0.69	1.97	0.69	1.04	0.67
11039	High Efficiency Central AC - 16 SEER	0.44	0.89	0.31	0.71	0.54
11040	Ductless mini-split AC	0.64	1.84	0.64	0.67	0.96

Measure-level Benefit-Cost Ratios

Measure #	Measure Name	TRC Test	Utility Cost Test	Societal Cost Test	Part. Test	RIM Test
11041	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	0.61	1.27	0.45	1.05	0.50
11042	Ground Source Heat Pump (HP Upgrade)	0.58	0.32	0.11	1.19	0.16
11043	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	1.43	4.71	1.35	1.59	0.76
11044	Ductless mini-split HP (replacing ASHP)	0.55	1.58	0.55	0.61	0.91
11045	ECM Furnace Fan	1.19	3.39	1.19	2.19	0.54
11046	Programmable Thermostat - Gas/AC	11.13	11.85	11.13	23.88	0.50
11047	Programmable Thermostat - ASHP	11.13	31.81	11.13	21.66	0.51
11048	Smart Thermostat - Gas Heat / AC	1.56	1.67	1.56	3.66	0.40
11049	Smart Thermostat - ASHP	1.56	4.47	1.56	3.35	0.47
11050	Energy Star Room A/C	0.69	1.97	0.69	1.04	0.67
11051	High Efficiency Central AC - 16 SEER	0.28	0.42	0.15	0.63	0.30
11052	Ductless mini-split AC	0.46	1.30	0.46	0.54	0.84
11053	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	0.43	0.73	0.25	0.84	0.38
11054	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	1.04	3.25	0.95	1.16	0.77
11055	Ductless mini-split HP (replacing ASHP)	0.46	1.30	0.46	0.50	0.90
11056	ECM Furnace Fan	1.19	3.39	1.19	2.19	0.54
11057	Programmable Thermostat - Gas/AC	6.68	7.59	6.68	14.42	0.49
11058	Programmable Thermostat - ASHP	6.47	18.49	6.47	12.74	0.51
11059	Smart Thermostat - Gas Heat / AC	0.94	1.07	0.94	2.33	0.35
11060	Smart Thermostat - ASHP	0.91	2.60	0.91	2.09	0.43
12000	Other					
12001	In Home Energy Display Monitor - Gas/CAC	1.90	2.34	1.90	4.36	0.43
12002	Home Energy Reports - Gas/CAC	0.64	0.71	0.64	1.84	0.27
12003	In Home Energy Display Monitor - ASHP	2.56	7.30	2.56	5.17	0.49
12004	Home Energy Reports - ASHP	0.77	2.20	0.77	2.11	0.36
12005	In Home Energy Display Monitor - Elec Furn/CAC	4.20	12.01	4.20	8.28	0.51
12006	Home Energy Reports - Elec Furn/CAC	1.27	3.62	1.27	3.25	0.39
12007	Two Speed Pool Pumps	5.40	15.43	5.40	2.58	2.10
12008	Variable Speed Pool Pumps	2.25	6.43	2.25	1.75	1.29
12009	Premium Efficiency Pool Pump Motor	11.06	31.60	11.06	7.57	1.46
12010	In Home Energy Display Monitor - Gas/CAC	1.27	1.51	1.27	3.04	0.39
12011	Home Energy Reports - Gas/CAC	0.43	0.46	0.43	1.35	0.22
12012	In Home Energy Display Monitor - ASHP	1.82	5.21	1.82	3.79	0.48
12013	Home Energy Reports - ASHP	0.55	1.57	0.55	1.61	0.34
12014	In Home Energy Display Monitor - Elec Furn/CAC	3.03	8.67	3.03	6.07	0.50
12015	Home Energy Reports - Elec Furn/CAC	0.91	2.61	0.91	2.44	0.37
12016	In Home Energy Display Monitor - Gas/CAC	1.68	1.71	1.68	3.94	0.40
12017	Home Energy Reports - Gas/CAC	0.57	0.51	0.57	1.68	0.24
12018	In Home Energy Display Monitor - ASHP	1.85	5.29	1.85	3.85	0.48
12019	Home Energy Reports - ASHP	0.56	1.60	0.56	1.63	0.34
12020	Two Speed Pool Pumps	5.40	15.43	5.40	2.58	2.10
12021	Variable Speed Pool Pumps	2.25	6.43	2.25	1.75	1.29
12022	Premium Efficiency Pool Pump Motor	11.06	31.60	11.06	7.57	1.46
12023	In Home Energy Display Monitor - Gas/CAC	1.12	1.10	1.12	2.77	0.36
12024	Home Energy Reports - Gas/CAC	0.39	0.33	0.39	1.25	0.19
12025	In Home Energy Display Monitor - ASHP	1.07	3.06	1.07	2.37	0.45
12026	Home Energy Reports - ASHP	0.32	0.92	0.32	1.09	0.30
13000	Multi-Family Units					
13001	Multi-Family Homes Efficiency Kit	1.77	1.68	1.77	2.48	0.45
13002	Multi-Family Homes Efficiency Kit	1.77	1.68	1.77	2.48	0.45
14000	New Construction Homes - Single Family					
14001	New Construction - 15% more efficient (w/AC only)	1.93	3.20	1.56	3.00	0.66
14002	New Construction - 15% more efficient (w/Elec. HP)	3.21	8.08	2.83	3.48	0.91
14003	New Construction - 15% more efficient (w/ Dual-Fuel HP (w/gas))	2.18	7.25	1.81	1.37	0.99
14004	New Construction - 15% more efficient (w/ Geothermal HP)	3.21	8.08	2.83	3.48	0.91
14005	New Construction - 30% more efficient (w/AC only)	1.06	2.11	0.91	1.95	0.52
14006	New Construction - 30% more efficient (w/Elec. HP)	1.88	4.94	1.73	2.71	0.68
14007	New Construction - 30% more efficient (w/ Dual-Fuel HP (w/gas))	1.35	4.27	1.20	1.64	0.70
14008	New Construction - 30% more efficient (w/ Geothermal HP)	1.88	4.94	1.73	2.71	0.68
14009	New Construction - 15% more efficient (w/AC only)	2.52	3.98	1.84	3.81	0.64
14010	New Construction - 15% more efficient (w/Elec. HP)	4.24	10.17	3.56	4.56	0.92
14011	New Construction - 30% more efficient (w/AC only)	1.40	2.72	1.13	2.47	0.53
14012	New Construction - 30% more efficient (w/Elec. HP)	2.46	6.27	2.19	3.46	0.69
15000	Early Retirement					
15001	Energy Star Room A/C - Early Retirement	0.40	1.13	0.40	0.91	0.44
15002	Energy Star Room A/C - Early Retirement	0.40	1.13	0.40	0.91	0.44
15003	Energy Star Room A/C - Early Retirement	0.40	1.13	0.40	0.91	0.44
15004	High Efficiency Central AC/Early Retire - 16 SEER	0.13	0.13	0.04	0.50	0.11
15005	High Efficiency Central AC/Early Retire - 16 SEER	0.13	0.13	0.04	0.50	0.11
15006	High Efficiency Central AC/Early Retire - 16 SEER	0.13	0.13	0.04	0.50	0.11
15007	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9.0 HSPF	0.15	0.22	0.08	0.57	0.16
15008	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9.0 HSPF	0.15	0.22	0.08	0.57	0.16
15009	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9.0 HSPF	0.15	0.22	0.08	0.57	0.16
15010	Ground Source Heat Pump/Early Retire (HP Upgrade)	0.47	0.16	0.05	0.88	0.12
15011	Ground Source Heat Pump/Early Retire (HP Upgrade)	0.47	0.16	0.05	0.88	0.12
15012	Ground Source Heat Pump/Early Retire (HP Upgrade)	0.47	0.16	0.05	0.88	0.12
15013	Heat Pump/Early Retire (Replacing Electric Furnace)	0.40	0.92	0.32	1.10	0.32
15014	Heat Pump/Early Retire (Replacing Electric Furnace)	0.40	0.92	0.32	1.10	0.32

Measure-level Benefit-Cost Ratios

Measure #	*Measure Name*	*TRC Test*	*Utility Cost Test*	*Societal Cost Test*	*Part. Test*	*RIM Test*
15015	Heat Pump/Early Retire (Replacing Electric Furnace)	0.40	0.92	0.32	1.10	0.32
15016	Energy Star Room A/C - Early Retirement	0.40	1.13	0.40	0.91	0.44
15017	Energy Star Room A/C - Early Retirement	0.40	1.13	0.40	0.91	0.44
15018	Energy Star Room A/C - Early Retirement	0.40	1.13	0.40	0.91	0.44
15019	High Efficiency Central AC/Early Retire - 16 SEER	0.12	0.08	0.03	0.48	0.07
15020	High Efficiency Central AC/Early Retire - 16 SEER	0.12	0.08	0.03	0.48	0.07
15021	High Efficiency Central AC/Early Retire - 16 SEER	0.12	0.08	0.03	0.48	0.07
15022	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9.0 HSPF	0.15	0.18	0.06	0.44	0.18
15023	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9.0 HSPF	0.15	0.18	0.06	0.44	0.18
15024	High Efficiency Heat Pump/Early Retire (HP Upgrade) - 16 SEER/9.0 HSPF	0.15	0.18	0.06	0.44	0.18
15025	Heat Pump/Early Retire (Replacing Electric Furnace)	0.37	0.80	0.28	0.44	0.80
15026	Heat Pump/Early Retire (Replacing Electric Furnace)	0.37	0.80	0.28	0.44	0.80
15027	Heat Pump/Early Retire (Replacing Electric Furnace)	0.37	0.80	0.28	0.44	0.80

Residential Load Shapes (listed by measure type)

	Allocation of Annual Energy Savings by Season			
Measure Type	Winter		Summer	
	Peak	***Off Peak***	***Peak***	***Off Peak***
A - Refrigerator	37%	18%	30%	15%
B - Freezer	39%	16%	32%	13%
C - Dehumidifier	13%	16%	32%	39%
D - Televisions	48%	19%	24%	9%
E - Home Computers	34%	33%	17%	16%
F - Power Strips	25%	34%	18%	24%
G - Flat	32%	35%	16%	18%
H - Indoor Lighting	48%	16%	26%	11%
I - Nightlight	0%	55%	0%	45%
J - Exterior Lighting	18%	44%	9%	28%
K - LF Faucet	49%	29%	14%	8%
L - LF Shower	49%	29%	14%	8%
M - HPWH	43%	21%	25%	12%
N- Solar WH	43%	21%	25%	12%
O - Dishwasher	49%	9%	36%	6%
P - Clothes Washer	47%	11%	34%	8%
Q - Heat & Cool	35%	23%	31%	11%
R - ECM	35%	23%	31%	11%
S - Thermostat	35%	23%	31%	11%
T - Cooling	4%	1%	71%	24%
U - Room Cooling	4%	1%	71%	24%
V - Continuous	36%	22%	26%	16%
W - Pool	0%	0%	65%	35%

APPENDIX B: COMMERCIAL & INDUSTRIAL MEASURE DETAIL

	Measure Name	Unit Notes	Annual kWh Saved	Percent Savings (kWh)	KW Savings	Summer KW Savings	Incremental Cost	Measure Useful Life	TRC	Direct Utility	Societal	Participant	RIM
1	***Lighting***												
1-1	Compact Fluorescent	bulb	189.9	70.6%	0.035	0.033	$2	3.2	30.7	83.4	30.7	34.1	0.9
1-2	LED Exit Sign	exit sign	83.0	72.6%	0.010	0.010	$30	16	3.9	6.2	3.9	4.9	0.7
1-3	High Performance T8 (vs T8) 4ft	fixture	46.9	16.9%	0.007	0.007	$41	15	0.9	2.9	0.9	1.3	0.7
1-4	Wall Mounted Occupancy Sensor	sensor	1253.0	30.0%	0.013	0.013	$55	10	9.7	32.6	9.7	14.5	0.7
1-5	Fixture Mounted Occupancy Sensor	sensor	736.8	30.0%	0.008	0.008	$67	10	4.7	15.7	4.7	7.2	0.7
1-6	Remote Mounted Occupancy Sensor	sensor	1944.2	30.0%	0.021	0.021	$125	10	6.7	22.3	6.7	10.0	0.7
1-7	High Bay 3 or 4 lamp T8VHO vs (Metal Halide 100W - 300W)	fixture	324.2	36.6%	0.067	0.056	$150	7	0.9	3.0	0.9	1.3	0.7
1-8	High Bay 6 or 8 lamp T8VHO vs (Metal Halide > 300W)	fixture	1073.7	40.9%	0.222	0.187	$200	7	2.3	7.5	2.3	2.8	0.8
1-9	High performance T5 (replacing T8)	fixture	84.0	28.0%	0.000	0.000	$40	15	1.0	3.6	1.0	2.1	0.5
1-10	CFL Hard Wired Fixture	fixture	185.6	69.0%	0.038	0.032	$38	12	3.4	11.0	3.4	3.9	0.9
1-11	CFL High Wattage 31-115	bulb	356.9	55.4%	0.074	0.062	$21	3.2	3.8	11.2	3.8	4.6	0.8
1-12	CFL High Wattage 150-199	bulb	1013.2	57.6%	0.210	0.176	$57	3.2	3.7	11.7	3.7	4.5	0.8
1-13	Low Bay LED (vs Metal Halide)	bulb	831.9	66.1%	0.172	0.145	$380	15	1.8	5.8	1.8	2.2	0.8
1-14	High Bay LED (vs Metal Halide)	bulb	618.6	49.2%	0.128	0.108	$480	15	1.1	3.4	1.1	1.4	0.8
1-15	Outdoor LED (vs Metal Halide)	bulb	250.0	63.4%	0.037	0.002	$221	17	2.9	3.4	2.9	3.2	0.8
1-16	Outdoor Induction (vs Metal Halide)	bulb	131.0	33.2%	0.020	0.001	$355	17	1.6	1.5	1.6	1.8	0.7
2	***Space Cooling***												
2-1	Split AC (13 SEER to 14.5 SEER)	5 ton	550.3	10.3%	0.000	0.353	$500	15	1.5	4.3	1.5	1.4	1.1
2-2	Split AC (13 SEER to 15 SEER)	5 ton	709.3	13.3%	0.000	0.455	$860	15	1.1	3.2	1.1	1.1	1.0
2-3	Split AC (13 SEER to 16 SEER)	5 ton	997.4	18.8%	0.000	0.640	$1,000	15	1.4	3.9	1.4	1.3	1.1
2-4	Split AC (11.4 IEER to 13 IEER)	8.3 ton	1244.4	12.3%	0.000	0.799	$830	15	2.1	5.9	2.1	1.8	1.2
2-5	Split AC (11.4 IEER to 14 IEER)	8.3 ton	1877.7	18.6%	0.000	1.206	$1,428	15	1.8	5.2	1.8	1.6	1.1
2-6	Split AC (11.4 IEER to 15 IEER)	8.3 ton	2426.5	24.0%	0.000	1.558	$1,660	15	2.0	5.7	2.0	1.7	1.2
2-7	DX Packaged System (CEE Tier 2)	10 ton	1047.8	8.3%	0.000	0.673	$607	15	2.4	6.8	2.4	2.0	1.2
2-8	DX Packaged System (CEE Tier 2)	< 20 ton	1921.0	10.0%	0.000	1.233	$910	15	2.9	8.3	2.9	2.4	1.2
2-9	DX Packaged System (CEE Tier 2)	> 20 ton	3195.5	7.6%	0.000	2.052	$1,813	15	2.4	6.9	2.4	2.0	1.2
2-10	Air Cooled Chiller	5 ton	1619.4	9.1%	0.000	0.422	$293	20	6.3	18.1	6.3	6.7	0.9
2-11	Air Cooled Chiller	8 ton	2591.0	9.1%	0.000	0.676	$469	20	6.3	18.1	6.3	6.7	0.9
2-12	PTAC	1/2 ton	201.2	31.9%	0.000	0.088	$50	15	4.6	13.0	4.6	4.2	1.1
2-13	PTAC	3/4 ton	178.2	21.1%	0.000	0.078	$75	15	2.7	7.7	2.7	2.6	1.0
2-14	PTAC	1 ton	352.9	31.8%	0.000	0.154	$100	15	4.0	11.4	4.0	3.7	1.1
2-15	PTAC	1 1/4 ton	469.2	28.9%	0.000	0.205	$150	15	3.5	10.1	3.5	3.3	1.1
2-16	HVAC Tune-Up		860.0	7.9%	0.000	0.570	$175	6	3.1	8.9	3.1	2.6	1.2
3	***Space Heating***												
3-1	PTHP	1/2 ton	785.4	19.2%	0.071	0.000	$50	15	9.7	27.6	9.7	15.2	0.6
3-2	PTHP	3/4 ton	1004.3	25.9%	0.131	0.000	$75	15	8.6	24.6	8.6	13.1	0.7
3-3	PTHP	1 ton	1445.8	35.2%	0.241	0.000	$100	15	9.6	27.5	9.6	14.1	0.7
3-4	PTHP	1 1/4 ton	1712.6	30.5%	0.285	0.000	$150	15	7.6	21.8	7.6	11.2	0.7
4	***Ventilation***												
4-1	Variable Frequency Drives	<2 HP	598.7	25.0%	0.154	0.170	$266	15	2.6	7.4	2.6	2.5	1.0
4-2	Variable Frequency Drives	3 to 10 HP	3592.3	25.0%	0.921	1.022	$1,622	15	2.6	7.3	2.6	2.5	1.0
4-3	Variable Frequency Drives	11 to 50 HP	16764.1	25.0%	4.298	4.771	$4,590	15	4.2	12.1	4.2	3.8	1.1
5	***Motors (Non-Ventilation)***												
5-1	Variable Frequency Drives	<2 HP	598.7	25.0%	0.154	0.154	$266	15	1.6	4.5	1.6	2.5	0.6
5-2	Variable Frequency Drives	3 to 10 HP	3592.3	25.0%	0.921	0.921	$1,622	15	1.5	4.4	1.5	2.5	0.6
5-3	Variable Frequency Drives	11 to 50 HP	16764.1	25.0%	4.298	4.298	$4,590	15	2.5	7.2	2.5	3.8	0.7
6	***Water Heating***												
6-1	High Efficiency Storage (tank)		256.0	5.4%	0.054	0.045	$70	10	2.4	7.0	2.4	2.9	0.8
6-2	Pre-Rinse Sprayer, Low flow, Commercial Application		1396.0	45.0%	0.233	0.196	$35	5	13.2	37.6	13.2	15.7	0.8

	Measure Name	Unit Notes	Annual kWh Saved	Percent Savings (kWh)	KW Savings	Summer KW Savings	Incremental Cost	Measure Useful Life	TRC	Direct Utility	Societal	Participant	RIM
6-3	On Demand (tankless)		345.0	7.4%	0.072	0.061	$350	20	1.1	3.2	1.1	1.5	0.8
6-4	Tank Insulation		512.0	30.0%	0.108	0.091	$60	12	6.6	18.9	6.6	7.2	0.9
6-5	Heat Pump Water Heater		5808.3	60.0%	0.567	0.476	$1,660	10	1.9	5.4	1.9	2.8	0.7
7	***Cooking***												
7-1	Electric Energy Star Fryers		983.0	11.7%	0.175	0.220	$500	12	7.8	22.3	7.8	1.9	4.1
7-2	Electric Energy Star Steamers,3-6 pan		10033.0	70.2%	1.527	1.924	$3,500	12	5.5	5.6	5.5	6.2	0.7
7-3	Energy Star Hot Food Holding Cabinet		3292.3	64.4%	0.401	0.505	$1,110	12	1.9	5.5	1.9	2.7	0.7
7-4	Energy Star Convection Ovens		3235.0	26.5%	0.492	0.620	$1,113	12	1.9	5.5	1.9	2.7	0.7
7-5	Energy Star Griddles		6996.0	39.5%	1.065	1.342	$2,090	12	2.2	6.3	2.2	3.0	0.7
8	***Refrigeration***												
8-1	Glass Door Freezer, <15-49 cu ft, Energy Star	Avg (7.5, 22.5, 40)	2478.0	31.4%	0.224	0.283	$158	12	10.7	30.5	10.7	12.9	0.8
8-2	Glass Door Freezer, 50+ cu ft, Energy Star	75 cu ft	8432.0	38.3%	0.761	0.963	$407	12	14.1	40.3	14.1	17.0	0.8
8-3	Solid Door Freezer, <15-49 cu ft, Energy Star	Avg (7.5, 22.5, 40)	1018.0	26.0%	0.092	0.116	$158	12	4.4	12.5	4.4	5.5	0.8
8-4	Solid Door Freezer, 50+ cu ft, Energy Star	75 cu ft	4817.0	42.1%	0.435	0.550	$407	12	8.1	23.0	8.1	9.9	0.8
8-5	Glass Door Refrigerator, <15 - 49 cu ft	Avg (7.5, 22.5, 40)	706.0	31.5%	0.064	0.081	$157	12	3.1	8.8	3.1	4.0	0.8
8-6	Glass Door Refrigerator, 50+ cu ft, Energy Star	75 cu ft	945.0	21.0%	0.085	0.108	$249	12	2.6	7.4	2.6	3.4	0.8
8-7	Solid Door Refrigerator, <15-49 cu ft, Energy Star	Avg (7.5, 22.5, 40)	505.0	31.6%	0.046	0.058	$157	12	2.2	6.3	2.2	2.9	0.7
8-8	Solid Door Refrigerator, 50+ cu ft, Energy Star	75 cu ft	1323.0	38.0%	0.119	0.151	$249	12	3.6	10.3	3.6	4.6	0.8
8-9	contained		537.0	7.0%	0.099	0.125	$75	1	0.6	1.6	0.6	0.9	0.6
8-10	Commercial Refrigeration Tune-Up, Low Temp, not self contained		1388.0	7.0%	0.191	0.241	$75	1	1.3	3.7	1.3	1.9	0.7
8-11	Anti-sweat heater controls on freezers	2 doors	2391.0	22.6%	0.000	0.000	$200	12	6.4	18.2	6.4	10.0	0.6
8-12	Anti-sweat heater controls, on refrigerators	2 doors	1128.0	36.0%	0.000	0.000	$200	12	3.0	8.6	3.0	4.9	0.6
8-13	Vending Miser, Cold Beverage		1612.0	46.0%	0.000	0.000	$216	5	1.4	4.0	1.4	3.2	0.4
8-14	Brushless DC Motors for freezers and coolers		1050.0	8.8%	0.010	0.013	$25	5	10.1	28.8	10.1	16.5	0.6
8-15	Humidity Door Heater Controls for freezers and coolers	2 doors	1383.0	55.0%	0.000	0.000	$300	12	2.5	7.0	2.5	4.1	0.6
8-16	Refrigerated Case Covers	6 linear feet	945.0	9.0%	0.000	0.000	$252	5	0.9	2.5	0.9	1.8	0.5
8-17	Zero Energy Doors for freezers and coolers		800.0	20.0%	0.165	0.208	$538	10	1.2	3.4	1.2	1.4	0.8
8-18	Evaporator Coil Defrost Control		600.0	43.6%	0.405	0.510	$500	10	1.9	5.5	1.9	1.2	1.6
8-19	Evaporator Fan Motor Control for freezers and coolers		2600.0	35.8%	0.059	0.074	$2,254	13	0.6	1.6	0.6	1.3	0.4
8-20	Ice Machine, Energy Star, Self-Contained		270.0	10.2%	0.029	0.037	$56	9	2.7	7.7	2.7	3.4	0.8
8-21	LED Case Lighting (per door)	per door	332.0	50.0%	0.039	0.049	$250	8.1	0.8	2.0	0.8	1.2	0.6
9	***Office Equipment/Appliances***												
9-1	Watt Sensors on Office Electronics	50 Watt	45.0	37.5%	0.000	0.000	$70	8	0.2	0.6	0.2	0.7	0.3
9-2	Watt Sensors on Office Electronics	150 Watt	124.0	39.4%	0.000	0.000	$70	8	0.6	1.7	0.6	1.4	0.4
10	***Compressed Air***												
10-1	Fix Air Leaks	<5HP	262.5	15.0%	0.063	0.080	$75	1	0.3	0.8	0.3	0.6	0.4
10-2	Fix Air Leaks	10-50HP	2009.7	15.0%	0.483	0.612	$75	1	2.0	5.8	2.0	2.6	0.8
10-3	Fix Air Leaks	50-100HP	6134.5	15.0%	1.475	1.867	$75	1	6.2	17.7	6.2	7.2	0.9
10-4	Engineered Nozzles for blow-off		888.0	3.9%	0.073	0.092	$14	15	48.2	137.6	48.2	60.5	0.8

	Measure Name	Annual kWh Saved	Winter KW Savings	Summer KW Savings	Incremental Cost	Measure Useful Life
1	*Lighting*					
1-1	Compact Fluorescent	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
1-2	LED Exit Sign	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
1-3	High Performance T8 (vs T8) 4ft	23 - Indiana	23 - Indiana	23 - Indiana	24 - Michigan	23 - Indiana
1-4	Wall Mounted Occupancy Sensor	25 - Vermont	25 - Vermont	25 - Vermont	25 - Vermont	25 - Vermont
1-5	Fixture Mounted Occupancy Sensor	25 - Vermont	25 - Vermont	25 - Vermont	25 - Vermont	25 - Vermont
1-6	Remote Mounted Occupancy Sensor	25 - Vermont	25 - Vermont	25 - Vermont	25 - Vermont	25 - Vermont
1-7	High Bay 3 or 4 lamp T8VHO vs (Metal Halide 100W - 300W)	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
1-8	High Bay 6 or 8 lamp T8VHO vs (Metal Halide > 300W)	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
1-9	High performance T5 (replacing T8)	17 - Vermont	17 - Vermont	4 - GDS	17 - Vermont	17 - Vermont
1-10	CFL Hard Wired Fixture	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
1-11	CFL High Wattage 31-115	4 - GDS	4 - GDS	4 - GDS	18 - Green Elec	23 - Indiana
1-12	CFL High Wattage 150-199	4 - GDS	4 - GDS	4 - GDS	18 - Green Elec	23 - Indiana
1-13	Low Bay LED (vs Metal Halide)	4 - GDS	4 - GDS	4 - GDS	18 - Green Elec	25 - Vermont
1-14	High Bay LED (vs Metal Halide)	4 - GDS	4 - GDS	4 - GDS	18 - Green Elec	25 - Vermont
1-15	Outdoor LED (vs Metal Halide)	26 - Big Rivers	26 - Big Rivers	26 - Big Rivers	26 - Big Rivers	26 - Big Rivers
1-16	Outdoor Induction (vs Metal Halide)	26 - Big Rivers	26 - Big Rivers	26 - Big Rivers	26 - Big Rivers	26 - Big Rivers
2	*Space Cooling*					
2-1	Split AC (13 SEER to 14.5 SEER)	4 - GDS	4 - GDS	4 - GDS	23 - Indiana	23 - Indiana
2-2	Split AC (13 SEER to 15 SEER)	4 - GDS	4 - GDS	4 - GDS	13 - ActOnEnergy	23 - Indiana
2-3	Split AC (13 SEER to 16 SEER)	4 - GDS	4 - GDS	4 - GDS	13 - ActOnEnergy	23 - Indiana
2-4	Split AC (11.4 IEER to 13 IEER)	4 - GDS	4 - GDS	4 - GDS	23 - Indiana	23 - Indiana
2-5	Split AC (11.4 IEER to 14 IEER)	4 - GDS	4 - GDS	4 - GDS	13 - ActOnEnergy	23 - Indiana
2-6	Split AC (11.4 IEER to 15 IEER)	4 - GDS	4 - GDS	4 - GDS	13 - ActOnEnergy	23 - Indiana
2-7	DX Packaged System (CEE Tier 2)	4 - GDS	4 - GDS	4 - GDS	19 - Connecticut	23 - Indiana
2-8	DX Packaged System (CEE Tier 2)	4 - GDS	4 - GDS	4 - GDS	19 - Connecticut	23 - Indiana
2-9	DX Packaged System (CEE Tier 2)	4 - GDS	4 - GDS	4 - GDS	19 - Connecticut	23 - Indiana
2-10	Air Cooled Chiller	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
2-11	Air Cooled Chiller	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
2-12	PTAC	4 - GDS	4 - GDS	4 - GDS	14 - Maine	14 - Maine
2-13	PTAC	4 - GDS	4 - GDS	4 - GDS	14 - Maine	14 - Maine
2-14	PTAC	4 - GDS	4 - GDS	4 - GDS	13 - ActOnEnergy	14 - Maine
2-15	PTAC	4 - GDS	4 - GDS	4 - GDS	13 - ActOnEnergy	14 - Maine
2-16	HVAC Tune-Up	26 - Big Rivers	26 - Big Rivers	26 - Big Rivers	26 - Big Rivers	26 - Big Rivers
3	*Space Heating*					
3-1	PTHP	4- GDS	4- GDS	4- GDS	13 - ActOnEnergy	4- GDS
3-2	PTHP	4- GDS	4- GDS	4- GDS	13 - ActOnEnergy	4- GDS
3-3	PTHP	4- GDS	4- GDS	4- GDS	13 - ActOnEnergy	4- GDS
3-4	PTHP	4- GDS	4- GDS	4- GDS	13 - ActOnEnergy	4- GDS
4	*Ventilation*					
4-1	Variable Frequency Drives	16 - Alliant	4 - GDS	4 - GDS	23 - Indiana	23 - Indiana
4-2	Variable Frequency Drives	16 - Alliant	4 - GDS	4 - GDS	23 - Indiana	23 - Indiana
4-3	Variable Frequency Drives	16 - Alliant	4 - GDS	4 - GDS	23 - Indiana	23 - Indiana
5	*Motors (Non-Ventilation)*					
5-1	Variable Frequency Drives	16 - Alliant	4 - GDS	4 - GDS	23 - Indiana	23 - Indiana
5-2	Variable Frequency Drives	16 - Alliant	4 - GDS	4 - GDS	23 - Indiana	23 - Indiana
5-3	Variable Frequency Drives	16 - Alliant	4 - GDS	4 - GDS	23 - Indiana	23 - Indiana
6	*Water Heating*					
6-1	High Efficiency Storage (tank)	9 - MPRP	4 - GDS	7 - Vermont/4 -GD	9 - MPRP	10 - Construction
6-2	Pre-Rinse Sprayer, Low flow, Commercial Application	24 - Michigan	24 - Michigan	7 - Vermont/4 -GD	24 - Michigan	23 - Indiana
6-3	On Demand (tankless)	11 - New York	4 - GDS	7 - Vermont/4 -GD	10 - Construction	10 - Construction
6-4	Tank Insulation	12 - Energy Experts	- Energy Expe	7 - Vermont/4 -GD	4 - GDS	12 - Energy Experts
6-5	Heat Pump Water Heater	23 - Indiana	4 - GDS	23 - Indiana	27 - ACEEE	23 - Indiana
7	*Cooking*					
7-1	Electric Energy Star Fryers	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
7-2	Electric Energy Star Steamers,3-6 pan	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
7-3	Energy Star Hot Food Holding Cabinet	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
7-4	Energy Star Convection Ovens	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
7-5	Energy Star Griddles	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
8	*Refrigeration*					
8-1	Glass Door Freezer, <15-49 cu ft, Energy Star	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
8-2	Glass Door Freezer, 50+ cu ft, Energy Star	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
8-3	Solid Door Freezer, <15-49 cu ft, Energy Star	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
8-4	Solid Door Freezer, 50+ cu ft, Energy Star	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana

	Measure Name	Annual kWh Saved	Winter KW Savings	Summer KW Savings	Incremental Cost	Measure Useful Life
1	*Lighting*					
1-1	Compact Fluorescent	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
1-2	LED Exit Sign	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
8-5	Glass Door Refrigerator, <15 - 49 cu ft	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
8-6	Glass Door Refrigerator, 50+ cu ft, Energy Star	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
8-7	Solid Door Refrigerator, <15-49 cu ft, Energy Star	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
8-8	Solid Door Refrigerator, 50+ cu ft, Energy Star	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
8-9	contained	7 - Wisconsin	7 - Wisconsin	22 - Arkansas	19 - Refrig	19 - Refrig
8-10	Commercial Refrigeration Tune-Up, Low Temp, not self contained	7 - Wisconsin	7 - Wisconsin	22 - Arkansas	19 - Refrig	19 - Refrig
8-11	Anti-sweat heater controls on freezers	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
8-12	Anti-sweat heater controls, on refrigerators	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
8-13	Vending Miser, Cold Beverage	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
8-14	Brushless DC Motors for freezers and coolers	17 - Vermont	17 - Vermont	22 - Arkansas	17 - Vermont	17 - Vermont
8-15	Humidity Door Heater Controls for freezers and coolers	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
8-16	Refrigerated Case Covers	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
8-17	Zero Energy Doors for freezers and coolers	17 - Vermont	17 - Vermont	22 - Arkansas	17 - Vermont	17 - Vermont
8-18	Evaporator Coil Defrost Control	17 - Vermont	17 - Vermont	22 - Arkansas	17 - Vermont	17 - Vermont
8-19	Evaporator Fan Motor Control for freezers and coolers	17 - Vermont	17 - Vermont	22 - Arkansas	17 - Vermont	17 - Vermont
8-20	Ice Machine, Energy Star, Self-Contained	7 - Wisconsin	7 - Wisconsin	22 - Arkansas	17 - Vermont	23 - Indiana
8-21	LED Case Lighting (per door)	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
9	*Office Equipment/Appliances*					
9-1	Watt Sensors on Office Electronics	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
9-2	Watt Sensors on Office Electronics	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana
10	*Compressed Air*					
10-1	Fix Air Leaks	2 - Alliant	4 - GDS			4 - GDS
10-2	Fix Air Leaks	2 - Alliant	4 - GDS			4 - GDS
10-3	Fix Air Leaks	2 - Alliant	4 - GDS			4 - GDS
10-4	Engineered Nozzles for blow-off	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana	23 - Indiana

SOURCE DESCRIPTIONS

1 - Michigan Master Measure Savings Database, January 2009
2 - Alliant Energy Calculator for Variable Frequency Drives - http://www.alliantenergy.com/UtilityServices/ForYourBusiness/EnergyExpertise/EnergySafety/010794
3 - Energy Star
4 - GDS Calculation/Estimation
5 - Nexant, 2005. NYSERDA Deemed Savings Measure Database. Prepared for NYSERDA
6 - Database for Energy Efficient Resources - http://www.energy.ca.gov/deer/
7 - Wisconsin KEMA Technical Manual
9 - MPRP Commercial Energy Efficiency and Demand Response Update Spreadsheet, June 2009.
10 - http://www.construction-today.com/cms1/content/view/1931/31/
11 - Energy Efficiency and Renewable Energy Resource Development Potential in New York State - Final Report, Volume 5 Energy Efficiency Technical Appendices, August 2
12 - http://energyexperts.org/EnergySolutionsDatabase/ResourceDetail.aspx?id=1243
13 - ActOnEnergy, Ameren Utilities Technical Resource Manual 2009
14 - Efficiency Maine, State of Maine Commercial Technical Resource Manual 2009
16 - http://www.alliantenergy.com/UtilityServices/ForYourBusiness/EnergyExpertise/EnergySafety/010794
17 - Efficiency Vermont Technical Reference User Manual - Measure Savinsg Algorithms and Cost assumptions - 2009
18 - http://www.greenelectricalsupply.com
19 - http://hvacrdistributionbusiness.com/hot_topics/refrigeration_new_commercial/
22- Arkansas Deemed Savings Manual Coincidence factor calculation
23 - Indiana Technical Resource Manual Version 1.0 January 10, 2013; TecMarket Works
24 - Michigan Master Measure Savings Database, July 2013
25 - Efficiency Vermont Technical Reference User Manual - Measure Savinsg Algorithms and Cost assumptions - 2013-83
26 - Big Rivers 2013 DSM Program Impact data
27 - ACEEE Consumer Resources: Water Heating http://www.aceee.org/consumer/water-heating

APPENDIX C: GLOBAL MODELING ASSUMPTIONS

GENERAL MODELING ASSUMPTIONS

Analysis Start Year	2014		***Nominal Discount Rate***	6.86%
Length of Analysis	10	Years	***Inflation Rate***	2.50%
			Reserve Margin Multiplier	14.0%

Avoided Costs (Nominal Dollars)

	Natural Gas Wholesale Forecast
Data Year	$/MMBTU
2014	4.72
2015	4.84
2016	4.96
2017	5.08
2018	5.21
2019	5.34
2020	5.47
2021	5.61
2022	5.75
2023	5.89
2024	6.04
2025	6.19
2026	6.35
2027	6.51
2028	6.67
2029	6.84
2030	7.01
2031	7.18
2032	7.36
2033	7.55
2034	7.73
2035	7.93
2036	8.13
2037	8.33
2038	8.54
2039	8.75
2040	8.97
2041	9.19

	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer Capacity	Winter Capacity	Avoided T&D Capacity
Data Year	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr
2014	0.038	0.029	0.040	0.028	0.38	0.38	0.00
2015	0.041	0.030	0.045	0.030	0.00	0.00	0.00
2016	0.044	0.031	0.048	0.031	84.45	84.45	0.00
2017	0.044	0.031	0.048	0.031	71.04	71.04	0.00
2018	0.051	0.034	0.055	0.034	81.23	81.23	0.00
2019	0.054	0.036	0.058	0.036	85.33	85.33	0.00
2020	0.055	0.037	0.059	0.037	85.76	85.76	0.00
2021	0.056	0.038	0.060	0.038	91.25	91.25	0.00
2022	0.057	0.039	0.061	0.039	91.82	91.82	0.00
2023	0.058	0.040	0.063	0.040	96.89	96.89	0.00
2024	0.061	0.043	0.067	0.042	98.92	98.92	0.00
2025	0.064	0.044	0.070	0.043	100.90	100.90	0.00
2026	0.065	0.044	0.071	0.044	102.91	102.91	0.00
2027	0.067	0.046	0.071	0.045	104.97	104.97	0.00
2028	0.068	0.046	0.072	0.045	107.06	107.06	0.00
2029	0.071	0.049	0.075	0.048	114.68	114.68	0.00
2030	0.073	0.050	0.078	0.049	122.30	122.30	0.00
2031	0.075	0.051	0.080	0.050	129.92	129.92	0.00
2032	0.077	0.053	0.082	0.052	137.54	137.54	0.00
2033	0.080	0.054	0.084	0.053	145.16	145.16	0.00
2034	0.082	0.055	0.087	0.054	152.78	152.78	0.00
2035	0.084	0.056	0.089	0.056	160.40	160.40	0.00
2036	0.086	0.058	0.091	0.057	168.02	168.02	0.00
2037	0.088	0.059	0.094	0.058	175.64	175.64	0.00
2038	0.091	0.060	0.096	0.060	183.26	183.26	0.00
2039	0.093	0.062	0.098	0.061	190.88	190.88	0.00
2040	0.095	0.063	0.101	0.062	198.50	198.50	0.00
2041	0.097	0.064	0.103	0.063	206.12	206.12	0.00

Retail Rates (Nominal Dollars)

Residential	Commercial	Industrial	Residential	Non-Residential	Water
$/kWh	$/kWh	$/kWh	$/MMBTU	$/MMBTU	$/gallon
0.0869	0.0896	0.0496	11.03	6.95	0.0088
0.0890	0.0918	0.0508	10.83	6.88	0.0090
0.0913	0.0941	0.0521	11.37	6.83	0.0092
0.0935	0.0965	0.0534	11.67	7.30	0.0095
0.0959	0.0989	0.0547	12.03	7.50	0.0097
0.0983	0.1014	0.0561	12.21	7.76	0.0100
0.1007	0.1039	0.0575	12.36	7.88	0.0102
0.1032	0.1065	0.0589	12.55	7.97	0.0105
0.1058	0.1092	0.0604	12.86	8.08	0.0107
0.1085	0.1119	0.0619	13.17	8.31	0.0110
0.1112	0.1147	0.0635	13.37	8.54	0.0113
0.1140	0.1176	0.0651	13.50	8.67	0.0115
0.1168	0.1205	0.0667	13.72	8.73	0.0118
0.1197	0.1235	0.0684	13.86	8.87	0.0121
0.1227	0.1266	0.0701	14.07	8.95	0.0124
0.1258	0.1298	0.0718	14.27	9.07	0.0127
0.1289	0.1330	0.0736	14.45	9.18	0.0131
0.1322	0.1363	0.0754	14.67	9.27	0.0134
0.1355	0.1398	0.0773	14.86	9.40	0.0137
0.1389	0.1432	0.0793	15.12	9.48	0.0141
0.1423	0.1468	0.0813	15.52	9.64	0.0144
0.1459	0.1505	0.0833	15.92	9.92	0.0148
0.1495	0.1543	0.0854	16.45	10.21	0.0151
0.1533	0.1581	0.0875	16.94	10.62	0.0155
0.1571	0.1621	0.0897	17.41	11.00	0.0159
0.1610	0.1661	0.0919	17.66	11.35	0.0163
0.1651	0.1703	0.0942	18.02	11.49	0.0167
0.1692	0.1745	0.0966	18.47	11.78	0.0171

Electric Line Losses

	Winter On Peak	Winter Off Peak	Summer On Peak	Summer Off Peak
Residential	1.0818	1.0818	1.0818	1.0818
C&I	1.0818	1.0818	1.0818	1.0818

Demand Line Losses

Winter Gen.	Summer Gen.	T&D Capacity
1.0818	1.0818	1.0000
1.0818	1.0818	1.0000

BIG RIVERS ELECTRIC DEMAND-SIDE MANAGEMENT POTENTIAL STUDY

FINAL REPORT

Prepared for:

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Appendix C
Staff Recommendations from the 2010 IRP

PSC Staff Recommendations to 2010 IRP

In the Staff Report on Big Rivers' 2010 IRP, Staff made recommendations for Big Rivers' consideration in future IRPs. These recommendations are identified and discussed below by planning function.

Load Forecast

- ***Big Rivers should present and discuss its specific models and equations with greater specificity. Underlying assumptions and modeling variables need to be explained clearly and concisely with as much detail as possible.***

  Refer to Section 4.6 for a detailed description of the forecasting models, including the theoretical assumptions supporting the model specifications and each model input.

- ***Big Rivers should consider updating its load forecast annually.***

  Big Rivers reviews its load forecast annually and adjusts the forecast as necessary for planning purposes. When significant changes occur, Big Rivers has updated its load forecast more frequently than every two years. Big Rivers submitted an updated load forecast to RUS in January 2013 as well as May 2013, each reflecting the loss of a smelter load. In accordance with guidelines established by the RUS and with its current Load Forecast Work Plan, which is approved by RUS, Big Rivers updates and files its load forecast with RUS at least every two years.

- ***Big Rivers should explicitly account for future DSM and energy efficiency programs in its load forecasts.***

  Big Rivers began explicitly accounting for future DSM and energy efficiency programs in its 2011 Load Forecast. The 2014 IRP is based on Big Rivers' 2013 Load Forecast, which also explicitly accounts for future program impacts. Refer to Appendix A, 2013 Load Forecast, Section 6.5, for details regarding how Big Rivers' future DSM and energy efficiency programs are quantified in the load forecast.

- ***Big Rivers should include pending EPA regulations and any other regulations that could potentially have major impacts upon its regional and service territory economies in its sensitivity analysis.***

  Refer to Section 4.7 for a discussion of the four sensitivities developed that address potential EPA regulations.

- ***Big Rivers should run forecast simulations in its sensitivity analysis in order to gain a better understanding of the probability of occurrence for the various scenarios, including the potential closure of one or both of the aluminum smelters.***

In addition to the base case forecast, Big Rivers prepared forecast scenarios to evaluate the impacts of varying economic conditions, market price sensitivities, fuel price sensitivities, weather conditions, and potential environmental regulations. Key model inputs were adjusted in developing the economy, market, fuel, weather, and environmental regulation scenarios and were set to values that Big Rivers believes would be similar to the 95% and 5% points of their respective probability distributions. The scenarios developed for potential environmental regulations reflect the sensitivity of energy and peak demand to various carbon tax levels relative to the base case forecast, as well as to increased rates due to other environmental expenditures.

Demand-Side Management

- ***Big Rivers should include environmental costs in future DSM evaluations and evaluate DSM as an environmental compliance option in addition to a resource option.***

  Environmental costs were considered in the DSM evaluation conducted for this IRP. No federal or state carbon emission legislation has been passed since 2010. For this reason, the DSM evaluation assumes a cost of $0/ton of carbon emissions in the avoided energy and capacity costs. This assumption properly estimates the cost of complying with environmental regulations at the present time. Additionally, Big Rivers evaluated environmental scenarios in the resource selection portion of the IRP process, including scenarios that include high and low projections of costs associated with carbon emissions.

  Big Rivers has been offering a menu of residential and commercial energy efficiency programs since October, 2011 in addition to energy efficiency consumer education with an annual budget of $1,000,000 collected in base rates through the Rural Delivery Service (RDS) rate schedule. Programs were tariffed in early 2012 and two additional programs were added in June 2013. 2014 is the first year all programs are expected to be offered through the entire calendar year.

- ***Big Rivers should aggressively pursue its new DSM programs in order to achieve the results projected in the IRP.***

  Section 5.3 summarizes the DSM activities each year including annual spending and savings. Spending has increased from approximately $109,000 to more than $1.3 million in 2013. Estimated energy savings have increased from 1,100 MWh in 2011 to nearly 14,000 MWh in 2013.

  Big Rivers has been offering a menu of residential and commercial energy efficiency programs since October 2011 in addition to energy efficiency consumer education with an annual budget of $1,000,000 collected in base rates through the Rural Delivery Service (RDS) rate schedule.

- ***Big Rivers should evaluate the feasibility of bundling measures that are marginally cost-effective into programs.***

The Residential Weatherization Program and Residential New Construction Program currently bundle measures that are marginally cost effective. For example, the supplemental attic insulation above R19 measure (TRC = .85) is bundled with highly cost effective measures such as duct sealing (TRC = 5.16). This bundling approach provides greater flexibility within the weatherization program to implement additional measures on a project by project basis.

- ***Big Rivers should take into consideration in future DSM analyses how its off-system sales can be affected by demand and energy reductions achieved through DSM programs.***

  Big Rivers factored in the effect of demand and energy reductions through DSM programs by valuing energy efficiency using avoided costs that are based on market prices. By valuing energy efficiency with market prices, any potential DSM savings that may result in excess generation and capacity are being valued similarly to any off-system sales possibilities.

- ***Big Rivers should include the impact of tax credits (if available) in future DSM evaluations.***

  The DSM evaluation conducted for this IRP included all known federal and state tax credits when performing the measure-level screening analysis and when calculated the portfolio-level cost-effectiveness results. The Database of State Incentives for Renewables & Efficiency (DSIRE) published by the U.S. Department of Energy informed the DSM evaluation process for which measures should be assumed to be eligible for tax credits. Federal and state tax credits were included in the evaluation. Measures that were impacted by the assumed tax credit availability include: geothermal heat pumps, heat pump water heaters, solar water heaters, air-source heat pumps, central air conditioners, and dual fuel heat pumps.

- ***Big Rivers should continue to monitor opportunities for demand response.***

  Refer to Section 5.2 of the IRP for a discussion of the demand response opportunities included in the DSM evaluation. Big Rivers' staff and Member Cooperatives, through the DSM Working Group continue to monitor advancements in demand response technology and AMI. In 2013 Working Group members from each Member Cooperative and Big Rivers visited three regional Generation and Transmission Cooperatives including East Kentucky Power, Hoosier Energy and Wabash Valley Electric to discuss and evaluate their current demand response programs. The Working Group also heard presentations from vendors associated with installed AMI technologies at two of the Member Cooperatives. In addition, the Working Group visited the Duke Energy's Envision Center in Erlanger, Kentucky.

- ***As an education tool, Big Rivers should consider developing a DSM education program for middle school students.***

  Big Rivers Member Cooperatives provide retail electric service to thousands of commercial members and more than 100,000 residential members. Big Rivers Members serve 9 middle schools in western Kentucky. Big Rivers and its Member Cooperatives did consider developing a DSM education program for middle school students and, although a great idea, concluded that limited resources could be used more effectively to address a larger group of members through other forms of education, such as website modules and mass-media promotion. GDS led this investigation by seeking a consensus from many of its industry colleagues with respect to the feasibility of quantifying measure savings from an educational program. The consensus opinion from GDS colleagues is that educational programs are typically employed to drive uptake in other energy efficiency programs and measures, but that measuring direct impacts of these types of programs may be too difficult given the extensive information and labor requirements to generate reliable savings estimates.

Supply-Side Resource Assessment

- ***Big Rivers should perform a utility-specific reserve margin study.***

  Refer to Section 10.3 Reserve Margin Study

- ***Big Rivers should continue to include consideration of renewable generation it its modeling and provide an in-depth discussion of its consideration of renewable power in its next IRP.***

  Biomass, landfill gas, wind, and photovoltaic resources were included in the list of potential resources in the preparation of this IRP (refer to Section 9). These resources were modeled in the same manner and at the same level of detail as the traditional supply-side options that were analyzed. Costs (both operating and capital) and operating parameters for the renewable and traditional resources were developed using information found in the Energy Information Administration's 2014 Annual Energy Outlook as well as information found in SNL Financial operating data. The Strategist system considered the renewable alternatives in the same manner in which the traditional resources were considered.

- ***Big Rivers should consider and discuss the consideration given to distributed generation in the resource plan.***

  [redacted].

  Refer to Section 10.

- ***Big Rivers should provide a detail discussion of the specific generation efficiency improvement activities it has undertaken.***

  Refer to Section 9.3 and Appendix F – Generating Unit Costs and Parameters for a discussion of the operations of Big Rivers' generating stations.

- ***A complete discussion of Big Rivers' compliance actions and plans relating to current and pending environmental regulations should be included in its next IRP.***

  Refer to Section 8 for a discussion of issues related to environmental regulations and compliance actions.

Integration and Plan Optimization

- ***Big Rivers' next IRP should include a more comprehensive assessment of alternative resources considered and environmental compliance strategies.***

  Biomass, landfill gas, wind, and photovoltaic resources were included in the list of potential resources in the preparation of this IRP. These resources were modeled in the same manner and at the same level of detail as the traditional supply-side options that were analyzed. Costs (both operating and capital) and operating parameters for the renewable and traditional resources were developed using information found in the Energy Information Administration's 2014 Annual Energy Outlook as well as information found in SNL Financial operating data. The Strategist system considered the renewable alternatives in the same manner in which the traditional resources were considered.

- ***Big Rivers should be more proactive in considering potential environmental regulations and more explicitly addressing them in future IRP filings.***

  The development of the 2014 IRP included analyses of several sensitivity cases that address potential environmental regulations. These sensitivity cases are based on load and energy forecasts developed specifically for each case, changes in operating costs at Big Rivers' generating units associated with implementation of environmental controls, and the inclusion of effluent specific costs.

- ***In future IRPs, Big Rivers should develop an optimal expansion plan based on the integration of supply-side and demand-side resources to produce the lowest cost plan.***

  As discussed in the IRP, the Base Case and all sensitivity cases include Big Rivers' $1 million DSM portfolio. Also, with the exception of the Extreme Weather and High Economics cases no new resources or load reductions are required in order to meet the reserve margin criteria used by the Strategist system. The Strategist system bases its selection of new resources on the least cost combination of existing and new resources that maintain minimum reserve criteria.

Appendix D
Cross-Reference to 807 KAR 5:058

Filing Requirement	Description	Section Reference in IRP Report
807 KAR 5:058 Section 1 (1)	General Provisions. This administrative regulation shall apply to electric utilities under commission jurisdiction except a distribution company with less than $10,000,000 annual revenue or a distribution cooperative organized under KRS Chapter 279.	Noted
807 KAR 5:058 Section 1 (2)	Each electric utility shall file triennially with the commission an integrated resource plan. The plan shall include historical and projected demand, resource, and financial data, and other operating performance and system information, and shall discuss the facts, assumptions, and conclusions, upon which the plan is based and the actions it proposes.	Noted
807 KAR 5:058 Section 1 (3)	Each electric utility shall file ten (10) bound copies and one (1) unbound, reproducible copy of its integrated resource plan with the commission	Big rivers is providing the required copies
807 KAR 5:058 Section 2 (1)	Filing Schedule. Each electric utility shall file its integrated resource plan according to a staggered schedule which provides for the filing of integrated resource plans one (1) every six (6) months beginning nine (9) months from the effective date of this administrative regulation.	Noted
807 KAR 5:058 Section 2 (1) (a)	The integrated resource plans shall be filed at the specified times following the effective date of this administrative regulation: 1. Kentucky Utilities Company shall file nine (9) months from the effective date; 2. Kentucky Power Company shall file fifteen (15) months from the effective date; 3. East Kentucky Power Cooperative, Inc. shall file twenty-one (21) months from the effective date; 4. The Union Light, Heat & Power Company shall file twenty-seven (27) months from the effective date; 5. Big Rivers Electric Corporation shall file thirty-three (33) months from the effective date; and 6. Louisville Gas & Electric Company shall file thirty-nine (39) months from the effective date.	Noted
807 KAR 5:058 Section 2 (1) (b)	The schedule shall provide at such time as all electric utilities have filed integrated resource plans, the sequence shall repeat.	Noted

Filing Requirement	Description	Section Reference in IRP Report
807 KAR 5:058 Section 2 (1) (c)	The schedule shall remain in effect until changed by the commission on its own motion or on motion of one (1) or more electric utilities for good cause shown. Good cause may include a change in a utility's financial or resource conditions.	Noted
807 KAR 5:058 Section 2 (1) (d)	If any filing date falls on a weekend or holiday, the plan shall be submitted on the first business day following the scheduled filing date.	Noted
807 KAR 5:058 Section 2 (2)	Immediately upon filing of an integrated resource plan, each utility shall provide notice to intervenors in its last integrated resource plan review proceeding, that its plan has been filed and is available from the utility upon request.	Notice has been provided
807 KAR 5:058 Section 2 (3)	Upon receipt of a utility's integrated resource plan, the commission shall establish a review schedule which may include interrogatories, comments, informal conferences, and staff reports.	Noted
807 KAR 5:058 Section 3	Waiver. A utility may file a motion requesting a waiver of specific provisions of this administrative regulation. Any request shall be made no later than ninety (90) days prior to the date established for filing the integrated resource plan. The commission shall rule on the request within thirty (30) days. The motion shall clearly identify the provision from which the utility seeks a waiver and provide justification for the requested relief which shall include an estimate of costs and benefits of compliance with the specific provision. Notice shall be given in the manner provided in Section 2(2) of this administrative regulation.	No waiver is requested at this time.
807 KAR 5:058 Section 4 (1)	Format. The integrated resource plan shall be clearly and concisely organized so that it is evident to the commission that the utility has complied with reporting requirements described in subsequent sections.	Section 1.1, Appendix D
807 KAR 5:058 Section 4 (2)	Each plan filed shall identify the individuals responsible for its preparation, who shall be available to respond to inquiries during the commission's review of the plan.	Section 1.2, Table 1.1
807 KAR 5:058 Section 5 (1)	Plan Summary. The plan shall contain a summary which discusses the utility's projected load growth and the resources planned to meet that growth. The summary shall include at a minimum: Description of the utility, its customers, service territory, current facilities, and planning objectives	Section 1

Filing Requirement	Description	Section Reference in IRP Report
807 KAR 5:058 Section 5 (2)	Description of models, methods, data, and key assumptions used to develop the results contained in the plan	Section 2
807 KAR 5:058 Section 5 (3)	Summary of forecasts of energy and peak demand, and key economic and demographic assumptions or projections underlying these forecasts	Section 1.5
807 KAR 5:058 Section 5 (4)	Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities	Section 1.6
807 KAR 5:058 Section 5 (5)	Steps to be taken during the next three (3) years to implement the plan	Section 1.8 Section 12
807 KAR 5:058 Section 5 (6)	Discussion of key issues or uncertainties that could affect successful implementation of the plan.	Section 1.7
807 KAR 5:058 Section 6	Significant Changes. All integrated resource plans, shall have a summary of significant changes since the plan most recently filed. This summary shall describe, in narrative and tabular form, changes in load forecasts, resource plans, assumptions, or methodologies from the previous plan. Where appropriate, the utility may also use graphic displays to illustrate changes.	Section 3
807 KAR 5:058 Section 7 (1) (a - g)	Load Forecasts. The plan shall include historical and forecasted information regarding loads. The information shall be provided for the total system and, where available, disaggregated by the following customer classes: (a) Residential heating; (b) Residential non-heating; (c) Total residential (total of paragraphs (a) and (b) of this subsection); (d) Commercial; (e) Industrial; (f) Sales for resale; (g) Utility use and other. The utility shall also provide data at any greater level of disaggregation available.	Section 4.1 Section 4.2
807 KAR 5:058 Section 7 (2)	The utility shall provide the following historical information for the base year, which shall be the most recent calendar year for which actual energy sales and system peak demand data are available, and the four (4) years preceding the base year:	Section 4

Filing Requirement	Description	Section Reference in IRP Report
807 KAR 5:058 Section 7 (2) (a)	Average annual number of customers by class as defined in subsection (1) of this section;	Section 4.2
807 KAR 5:058 Section 7 (2) (b)	Recorded and weather-normalized annual energy sales and generation for the system, and sales disaggregated by class as defined in subsection (1) of this section	Section 4.2 Section 4.3
807 KAR 5:058 Section 7 (2) (c)	Recorded and weather-normalized coincident peak demand in summer and winter for the system	Section 4.3
807 KAR 5:058 Section 7 (2) (d)	Total energy sales and coincident peak demand to retail and wholesale customers for which the utility has firm, contractual commitments	Section 4.1
807 KAR 5:058 Section 7 (2) (e)	Total energy sales and coincident peak demand to retail and wholesale customers for which service is provided under an interruptible or curtailable contract or tariff or under some other nonfirm basis	Section 4.2.7
807 KAR 5:058 Section 7 (2) (f)	Annual energy losses for the system	Section 4.1
807 KAR 5:058 Section 7 (2) (g)	Identification and description of existing demand-side programs and an estimate of their impact on utility sales and coincident peak demands including utility or government sponsored conservation and load management programs	Section 5.1
807 KAR 5:058 Section 7 (2) (h)	Any other data or exhibits, such as load duration curves or average energy usage per customer, which illustrate historical changes in load or load characteristics.	Section 4.5
807 KAR 5:058 Section 7 (3)	For each of the fifteen (15) years succeeding the base year, the utility shall provide a base load forecast it considers most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system. Forecasts shall not include load impacts of additional, future demand-side programs or customer generation included as part of planned resource acquisitions estimated separately and reported in Section 8(4) of this administrative regulation. Forecasts shall include the utility's estimates of existing and continuing demand-side programs as described in subsection (5) of this section.	Section 4.1 Section 4.7
807 KAR 5:058 Section 7 (4) (a)	Annual energy sales and generation for the system and sales disaggregated by class as defined in subsection (1) of this section	Section 4.1 Section 4.2
807 KAR 5:058 Section 7 (4) (b)	Summer and winter coincident peak demand for the system	Section 4.3

Filing Requirement	Description	Section Reference in IRP Report
807 KAR 5:058 Section 7 (4) (c)	If available for the first two (2) years of the forecast, monthly forecasts of energy sales and generation for the system and disaggregated by class as defined in subsection (1) of this section and system peak demand	Section 4.1
807 KAR 5:058 Section 7 (4) (d)	The impact of existing and continuing demand-side programs on both energy sales and system peak demands, including utility and government sponsored conservation and load management programs	Section 4.4 Section 5.1
807 KAR 5:058 Section 7 (4) (e)	Any other data or exhibits which illustrate projected changes in load or load characteristics	Section 4.5
807 KAR 5:058 Section 7 (5) (a)	The additional following data shall be provided for the integrated system, when the utility is part of a multistate integrated utility system, and for the selling company, when the utility purchases fifty (50) percent of its energy from another company For the base year and the four (4) years preceding the base year: 1. Recorded and weather normalized annual energy sales and generation; 2. Recorded and weather-normalized coincident peak demand in summer and winter.	Not Applicable as Big Rivers is not part of a multistate integrated utility system
807 KAR 5:058 Section 7 (5) (b)	The additional following data shall be provided for the integrated system, when the utility is part of a multistate integrated utility system, and for the selling company, when the utility purchases fifty (50) percent of its energy from another company: For each of the fifteen (15) years succeeding the base year: 1. Forecasted annual energy sales and generation; 2. Forecasted summer and winter coincident peak demand	Not Applicable as Big Rivers is not part of a multistate integrated utility system
807 KAR 5:058 Section 7 (6)	A utility shall file all updates of load forecasts with the commission when they are adopted by the utility.	Noted
807 KAR 5:058 Section 7 (7) (a)	The plan shall include a complete description and discussion of all data sets used in producing the forecasts	Section 4.6.1 Section 4.6.2
807 KAR 5:058 Section 7 (7) (b)	The plan shall include a complete description and discussion of key assumptions and judgments used in producing forecasts and determining their reasonableness	Section 4.6.3

Filing Requirement	Description	Section Reference in IRP Report
807 KAR 5:058 Section 7 (7) (c)	The plan shall include a complete description and discussion of the general methodological approach taken to load forecasting (for example, econometric, or structural) and the model design, model specification, and estimation of key model parameters (for example, price elasticities of demand or average energy usage per type of appliance)	Section 4.6 Section 4.6.4 Appendix A
807 KAR 5:058 Section 7 (7) (d)	The plan shall include a complete description and discussion of the utility's treatment and assessment of load forecast uncertainty	Section 4.7
807 KAR 5:058 Section 7 (7) (e)	The extent to which the utility's load forecasting methods and models explicitly address and incorporate the following factors: 1. Changes in prices of electricity and prices of competing fuels; 2. Changes in population and economic conditions in the utility's service territory and general region; 3. Development and potential market penetration of new appliances, equipment, and technologies that use electricity or competing fuels; and 4. Continuation of existing company and government sponsored conservation and load management or other demand-side programs	Section 4.6
807 KAR 5:058 Section 7 (7) (f)	Research and development efforts underway or planned to improve performance, efficiency, or capabilities of the utility's load forecasting methods	Section 4.8
807 KAR 5:058 Section 7 (7) (g)	Description of and schedule for efforts underway or planned to develop end-use load and market data for analyzing demand-side resource options including load research and market research studies, customer appliance saturation studies, and conservation and load management program pilot or demonstration projects. Technical discussions, descriptions, and supporting documentation shall be contained in a technical appendix	Section 4.8
807 KAR 5:058 Section 8 (1)	Resource Assessment and Acquisition Plan. The plan shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility.	Section 9

Filing Requirement	Description	Section Reference in IRP Report
807 KAR 5:058 Section 8 (2) (a)	The utility shall describe and discuss all options considered for inclusion in the plan including Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities	Section 9.1
807 KAR 5:058 Section 8 (2) (b)	The utility shall describe and discuss all options considered for inclusion in the plan including Conservation and load management or other demand-side programs not already in place	Section 9.2 Section 9.3
807 KAR 5:058 Section 8 (2) (c)	The utility shall describe and discuss all options considered for inclusion in the plan including: expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units	Section 9.2
807 KAR 5:058 Section 8 (2) (d)	The utility shall describe and discuss all options considered for inclusion in the plan including: assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources	Section 9.2
807 KAR 5:058 Section 8 (3)	The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs	Noted
807 KAR 5:058 Section 8 (3) (a)	A map of existing and planned generating facilities, transmission facilities with a voltage rating of sixty-nine (69) kilovolts or greater, indicating their type and capacity, and locations and capacities of all interconnections with other utilities. The utility shall discuss any known, significant conditions which restrict transfer capabilities with other utilities	Section 1.3.3 Appendix E

Filing Requirement	Description	Section Reference in IRP Report
807 KAR 5:058 Section 8 (3) (b) (*1-11*)	A list of all existing and planned electric generating facilities which the utility plans to have in service in the base year or during any of the fifteen (15) years of the forecast period, including for each facility: 1. Plant name; 2. Unit number(s); 3. Existing or proposed location; 4. Status (existing, planned, under construction, etc.); 5. Actual or projected commercial operation date; 6. Type of facility; 7. Net dependable capability, summer and winter; 8. Entitlement if jointly owned or unit purchase; 9. Primary and secondary fuel types, by unit; 10. Fuel storage capacity; 11. Scheduled upgrades, deratings, and retirement dates	Section 9.2 Table 9.3
807 KAR 5:058 Section 8 (3) (b) (*12*)	Actual and projected cost and operating information for the base year (for existing units) or first full year of operations (for new units) and the basis for projecting the information to each of the fifteen (15) forecast years (for example, cost escalation rates). All cost data shall be expressed in nominal and real base year dollars a. Capacity and availability factors; b. Anticipated annual average heat rate; c. Costs of fuel(s) per millions of British thermal units (MMBtu); d. Estimate of capital costs for planned units (total and per kilowatt of rated capacity); e. Variable and fixed operating and maintenance costs; f. Capital and operating and maintenance cost escalation factors; g. Projected average variable and total electricity production costs (in cents per kilowatt-hour).	Section 9.2 Table 9.2
807 KAR 5:058 Section 8 (3) (c)	Description of purchases, sales, or exchanges of electricity during the base year or which the utility expects to enter during any of the fifteen (15) forecast years of the plan	Section 10 Table 10.2

Filing Requirement	Description	Section Reference in IRP Report
807 KAR 5:058 Section 8 (3) (d)	Description of existing and projected amounts of electric energy and generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other nonutility sources available for purchase by the utility during the base year or during any of the fifteen (15) forecast years of the plan	Section 9
807 KAR 5:058 Section 8 (3) (e)	For each existing and new conservation and load management or other demand-side programs included in the plan: 1. Targeted classes and end-uses; 2. Expected duration of the program; 3. Projected energy changes by season, and summer and winter peak demand changes; 4. Projected cost, including any incentive payments and program administrative costs; and 5. Projected cost savings, including savings in utility's generation, transmission and distribution costs	Section 5.1 Tables 5.4-5.12

Filing Requirement	Description	Section Reference in IRP Report
807 KAR 5:058 Section 8 (4) (a)	The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast: (a) On total resource capacity available at the winter and summer peak: 1. Forecast peak load; 2. Capacity from existing resources before consideration of retirements; 3. Capacity from planned utility-owned generating plant capacity additions; 4. Capacity available from firm purchases from other utilities; 5. Capacity available from firm purchases from nonutility sources of generation; 6. Reductions or increases in peak demand from new conservation and load management or other demand-side programs; 7. Committed capacity sales to wholesale customers coincident with peak; 8. Planned retirements; 9. Reserve requirements; 10. Capacity excess or deficit; 11. Capacity or reserve margin.	Section 10 Table 10.1
807 KAR 5:058 Section 8 (4) (b)	On planned annual generation: 1. Total forecast firm energy requirements; 2. Energy from existing and planned utility generating resources disaggregated by primary fuel type; 3. Energy from firm purchases from other utilities; 4. Energy from firm purchases from nonutility sources of generation; and 5. Reductions or increases in energy from new conservation and load management or other demand-side programs	Section 10 Table 10.2

Filing Requirement	Description	Section Reference in IRP Report
807 KAR 5:058 Section 8 (4) (c)	For each of the fifteen (15) years covered by the plan, the utility shall provide estimates of total energy input in primary fuels by fuel type and total generation by primary fuel type required to meet load. Primary fuels shall be organized by standard categories (coal, gas, etc.) and quantified on the basis of physical units (for example, barrels or tons) as well as in MMBtu.	Section 9.2 Table 9.6
807 KAR 5:058 Section 8 (5) (a)	The resource assessment and acquisition plan shall include a description and discussion of: General methodological approach, models, data sets, and information used by the company;	Section 9
807 KAR 5:058 Section 8 (5) (b)	The resource assessment and acquisition plan shall include a description and discussion of: key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses	Section 10.2
807 KAR 5:058 Section 8 (5) (c)	The resource assessment and acquisition plan shall include a description and discussion of: Criteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan	Section 10
807 KAR 5:058 Section 8 (5) (d)	The resource assessment and acquisition plan shall include a description and discussion of: Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options	Section 10.3
807 KAR 5:058 Section 8 (5) (e)	The resource assessment and acquisition plan shall include a description and discussion of: Existing and projected research efforts and programs which are directed at developing data for future assessments and refinements of analyses	Section 4.8
807 KAR 5:058 Section 8 (5) (f)	The resource assessment and acquisition plan shall include a description and discussion of: Actions to be undertaken during the fifteen (15) years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990, and how these actions affect the utility's resource assessment	Section 8

Filing Requirement	Description	Section Reference in IRP Report
807 KAR 5:058 Section 8 (5) (g)	The resource assessment and acquisition plan shall include a description and discussion of: Consideration given by the utility to market forces and competition in the development of the plan. Technical discussion, descriptions and supporting documentation shall be contained in a technical appendix	Section 9 Appendix G
807 KAR 5:058 Section 9 (1)	Financial Information. The integrated resource plan shall, at a minimum, include and discuss the following financial information: Present (base year) value of revenue requirements stated in dollar terms	Section 11
807 KAR 5:058 Section 9 (2)	The integrated resource plan shall, at a minimum, include and discuss the following financial information: Discount rate used in present value calculations	Section 11
807 KAR 5:058 Section 9 (3)	The integrated resource plan shall, at a minimum, include and discuss the following financial information: Nominal and real revenue requirements by year	Section 11
807 KAR 5:058 Section 9 (4)	The integrated resource plan shall, at a minimum, include and discuss the following financial information: Average system rates (revenues per kilowatt hour) by year	Section 11
807 KAR 5:058 Section 10	Notice. Each utility which files an integrated resource plan shall publish, in a form prescribed by the commission, notice of its filing in a newspaper of general circulation in the utility's service area. The notice shall be published not more than thirty (30) days after the filing date of the report	Notice will be published within 30 days of the filing of the IRP
807 KAR 5:058 Section 11 (1)	Procedures for Review of the Integrated Resource Plan. Upon receipt of a utility's integrated resource plan, the commission shall develop a procedural schedule which allows for submission of written interrogatories to the utility by staff and intervenors, written comments by staff and intervenors, and responses to interrogatories and comments by the utility	Noted
807 KAR 5:058 Section 11 (2)	The commission may convene conferences to discuss the filed plan and all other matters relative to review of the plan	Noted
807 KAR 5:058 Section 11 (3)	Based upon its review of a utility's plan and all related information, the commission staff shall issue a report summarizing its review and offering suggestions and recommendations to the utility for subsequent filings	Noted
807 KAR 5:058 Section 11 (4)	A utility shall respond to the staff's comments and recommendations in its next integrated resource plan filing	Appendix C

Appendix E
Transmission System Map

[REDACTED]

BIG RIVERS ELECTRIC CORPORATION

2014 INTEGRATED RESOURCE PLAN

APPENDIX E
TRANSMISSION SYSTEM MAP

CONFIDENTIAL

Information Submitted under Petition for Confidential Treatment

Appendix F
Generating Unit Costs and Parameters

[REDACTED]

BIG RIVERS ELECTRIC CORPORATION

2014 INTEGRATED RESOURCE PLAN

APPENDIX F
GENERATING UNIT COSTS AND PARAMETERS

CONFIDENTIAL

Information Submitted under Petition for Confidential Treatment

Appendix G
Economy Energy Market Prices

[REDACTED]

BIG RIVERS ELECTRIC CORPORATION

2014 INTEGRATED RESOURCE PLAN

APPENDIX G
ECONOMY ENERGY MARKET PRICES

CONFIDENTIAL

Information Submitted under Petition for Confidential Treatment

Appendix H
Strategist Model Outputs

[REDACTED]

BIG RIVERS ELECTRIC CORPORATION

2014 INTEGRATED RESOURCE PLAN

APPENDIX H
STRATEGIST MODEL OUTPUTS

CONFIDENTIAL

Information Submitted on a Confidential CD under Petition for Confidential Treatment

Appendix I
Glossary

Glossary

ABB	Asea Brown Boveri
ACI	Activated Carbon Injection
Alcan	Alcan Primary Products Corporation
BAT	Best Available Technology Economically Available
Big Rivers	Big Rivers Electric Corporation
BPJ	Best Professional Judgment
BREC	Big Rivers Electric Corporation
C&I	Commercial and Industrial
CAIR	Clean Air Interstate Rule
CCRs	Coal Combustion Residuals
Century	Century Aluminum of Kentucky General Partnership
Century Hawesville	Aluminum smelter in Hawesville, Kentucky
Century Sebree	Aluminum smelter in Sebree, Kentucky, purchased by Century
CFL	Compact Fluorescent Light
CHP	Combined Heat and Power
CO2	Carbon Dioxide
Commission	Kentucky Public Service Commission
CPCN	Certificate of Public Convenience and Necessity
CPP	Critical Peak Pricing
CROs	Control Room Operators
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
DCS	Distributed Control System
DOE	U. S. Department of Energy
DSI	Dry Sorbent Injection
DSM	Demand-Side Management
EE	Energy Efficiency
EFORd	Unit Forced Outage Rates
EHV	Extra High Voltage
EIA	Energy Information Administration
ELG	Effluent Limitation Guidelines
EMS	Energy Management System
EPA	Environmental Protection Agency
ETS	Electric Thermal Storage
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulphurization
GADS	Generator Availability Data System
GAF	Strategist Generation and Fuel module

GDP	Gross Domestic Product
GDS	GDS Associates, Inc.
GE MARS	GE's Multi-Area Reliability Simulation
GHG	Greenhouse gases
GKS	Generation Knowledge Service
GVTC	Generator Verification Test Capacities
HAPs	Hazardous air pollutants
HCl	Hydrogen Chloride
Hg	Mercury
HMP&L	Henderson Municipal Power and Light
HMP&L Station Two	William L. Newman Station Two
HVAC	Heating, Ventilation, and Air Conditioning
ICAP	Installed Capacity
IRP	Integrated Resource Plan
JPEC	Jackson Purchase Energy Corporation
Kenergy	Kenergy Corp.
KPDES	Kentucky Pollutant Discharge Elimination System
KU	Kentucky Utilities Company
LBA	Local Balancing Authorities
LED	Light Emitting Diode
LFA	Strategist Load Forecast Adjustment module
LFU	Load Forecast Uncertainty
LIC	Large Industrial Customer Tariff
LOI	Loss of Ignition
LOLE	Loss of Load Expectation
LRZ	Local Resource Zone
LSE	Load Serving Entity
MAPE	Mean absolute percent error
MATS	Mercury and Air Toxics Standards
MCRECC	Meade County Rural Electric Cooperative Corporation
Members	Collectively: MCRECC, Kenergy, JPEC
MISO	Midcontinent Independent System Operator, Inc.
Mitigation Plan	Described in Section 12.3
MRSM	Member Rate Stability Mechanism
MSW	Municipal Solid Waste
MTEP	MISO Transmission Expansion Planning
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxides
NPV	Net Present Value
O&M	Operating and Maintenance
PCT	Participant Cost Tests

PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PSC	Public Service Commission
RCRA	Resource Conservation and Recovery Act
RCUST	Rural system customers
REM/Rate	Energy modeling software
RUS	Rural Utilities Services
RUSE	Rural system energy use per customer
SCR	Selective Catalytic Reduction
SEPA	Southeastern Power Administration
SERC	Southeast Electric Reliability Corporation
SO_2	Sulfur Dioxide
SSR	System Support Resource
The 2010 IRP	Case No. 2010-00443
TOU	Time of Use Rates
TRC	Total Resources Cost
TRMs	Technical reference manuals
TSS	Total suspended solids
UCAP	Unforced Capacity
UCT	Utility Cost Test
XEFORd	Unit Forced Outage Rates